NET ENERGY METERING, ZERO NET ENERGY AND THE DISTRIBUTED ENERGY RESOURCE FUTURE

ADAPTING ELECTRIC UTILITY BUSINESS MODELS FOR THE 21ST CENTURY

CONTENTS

EXECUTIVE SUMMARY

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California's electricity system stands at the forefront of changes that are transforming the electricity industry globally. These changes include integration of increasing amounts of renewable electricity supplies, creation and execution of programs to improve customers' energy efficiency, and implementation of new smart grid technologies for better coordination, control, and communication in managing the electricity grid. Today, however, an even more fundamental shift is taking place. New technologies and service offerings are emerging to grant customers unprecedented options in managing their energy consumption, generating electricity onsite, charging electric vehicles, and a host of other activities.

The increasing scope and power of customer decisions bring a new dimension to the electric utility business environment. Whereas utilities have traditionally exercised a high degree of control over investment decisions and operational management for most electricity system assets, utilities' future role could increasingly entail coordinating a vast array of supply- and demand-side resources owned and operated by tens of thousands—potentially millions—of independent actors. Based on publically announced power purchase agreement (PPA) contracts, the California Solar Initiative goals, and Gov. Brown's targets for distributed renewables, one-fourth of the total new investments in generating capacity in PG&E's service territory between 2012 and 2020 could come on the customer's side of the meter, largely in the form of rooftop solar PV systems. In parallel with these trends, growing numbers of buildings, campuses, and communities that meet California's Zero Net Energy policy goals will be exporting and importing electricity to and from the grid, bringing fundamental changes to the relationship between these customers and the utility. In short, the electricity system of the future is likely to encompass an increasingly diverse and interconnected set of actors, with widely varying assets, behaviors, and motivations.

If this emerging system is to sustainably achieve societal goals for the electricity system—providing reliable and resilient energy services at reasonable cost while meeting standards for fairness and environmental stewardship—then the decisions and behaviors of utilities and their customers must be harmonized to an unprecedented degree. The behaviors of many actors must be aligned to match fluctuations of supply and demand in real time. Investments in distributed resources must be made with a view to the temporal and geographic variations in the value and cost of electricity supply. Overall, the effectiveness of a utility's role in conducting the orchestra of distributed energy resources that interact with its system will be a critical factor in achieving favorable outcomes for all stakeholders. And the long-term health and stability of the electricity grid will be essential to making such a system work.

Existing utility rate structures and business models, which have evolved over time to meet a complex set of policy and economic goals, are poorly adapted to this new environment. Already, there are signs of growing tensions and conflicts among stakeholders in the electricity system as distributed resources are more widely deployed. Rate structures and incentives designed to stimulate the early adoption and scale-up of rooftop solar systems, electric vehicles, and other new technologies and design approaches will need to be modified over time, as adoption rates increase. New technologies and design practices call for new approaches to managing utility operations and pricing electricity services to accurately reflect benefits and costs of distributed resources and provide a sustainable path for the increased deployment of these resources.

To explore these issues, Rocky Mountain Institute and PG&E convened a roundtable composed of leading policy experts and industry and customer representatives. The work of the roundtable was to build a shared understanding of the problems and challenges facing stakeholders in the electric system and to identify the essential characteristics of workable long-term solutions.

While the roundtable's participants represented a diverse set of perspectives on the issues, the participants agreed that three key building blocks will be essential in developing solutions to the challenges discussed:

1. IDENTIFY AND MEASURE IMPACTS, COSTS AND VALUES OF DISTRIBUTED ENERGY RESOURCES

Building a shared understanding among stakeholders in the electricity industry of the full range of costs and benefits of distributed resources is an essential first step toward devising the business strategies, rates, and incentives that will create the greatest benefit for all. Select utilities, national labs, and other research organizations are starting to identify and analyze these costs and benefits, such as the capital and operating expenses incurred or avoided as a result of distributed generation installation. However, experience with high penetration of distributed generation, especially solar PV, is limited, and many questions remain about (a) the types of costs and benefits that may be incurred, (b) the magnitude of these costs and benefits, and (c) the degree to which these costs and benefits may be influenced by utility rates and other incentives.

In California, studies using differing methods and assumptions have reached varying conclusions about the degree to which net metering results in a "cost shift" from customers adopting solar PV to other customers.[1,2,3] Based on these competing studies, there are diverse opinions and projections about the rate impacts of increased solar penetration in the future. For example, PG&E projects that the adoption of large amounts of solar photovoltaics (PV) on customer sites would increase the utility's top-tier residential rates significantly[4], leading to higher adoption of distributed solar by customers in these rate classes. However, there remains a lack of consensus about analysis methods and data.

More rigorous analysis is needed to fully assess the costs and benefits of distributed resources for California's electric utilities and the potential for change in these costs and benefits in the future as penetration rates increase and new technologies are integrated on both the customer and grid side of the meter. Such analysis will require evaluation of impacts of distribution system capital and operating costs, equipment lifetimes, balancing costs, generation capacity costs, fuel price risks, implications for the reliability and resilience of the electricity grid, and a wide range of other considerations. New data collection and analysis methods will be necessary to develop estimates of these costs and benefits while ensuring accountability, transparency, and verifiability of cost and benefit estimates that will provide the foundation for policymaking.

2. REMEDY MISALIGNMENTS BETWEEN ECONOMIC INCENTIVES TO CUSTOMERS AND THE COST AND VALUE TO THE SYSTEM PROVIDED BY DISTRIBUTED RESOURCES

Existing rates and incentives fail to provide accurate economic signals to align distributed generation investment with system costs and benefits over the long term. Retail net energy metering, combined with tiered volumetric rates does not provide a sustainable long-term business model for electric utilities, nor does it provide accurate price signals for customers. As more investment is made outside of the utility's control, new rate structures, price signals and incentives will be critical for directing that investment for greatest system benefit. For example, these signals might provide incentives for the customer to reduce demand on the system during peak periods, or to provide voltage support or other ancillary services that reduce overall system costs. These solutions could require fundamental changes in existing non-time differentiated tiered rate structures, which allow little flexibility to accurately reflect costs of serving customers with distributed generation capabilities. Given the right price signals, distributed generators can adapt over the long term to provide new sources of value to the utility system. This change, however, would require a significant restructuring of existing rates, creating greater complexity in customers' bills.

3. ADAPT UTILITY BUSINESS MODELS TO CREATE AND SUSTAIN VALUE IN A FUTURE CHARACTERIZED BY HIGHER LEVELS OF EFFICIENCY AND INCREASED DEPLOYMENT OF DISTRIBUTED RESOURCES

Utilities have important and valuable roles as enablers and integrators in the deployment and operation of distributed resources. However, proliferation of distributed energy resources pose challenges to existing utility business models, whose basic tenets were designed under a production and delivery model dominated by centralized generation and one-way distribution. Further, electric utility business models exist within the context of regulatory structures that shape the roles of key actors, influence how markets evolve and, ultimately, control the gateway to the available technical solutions.

Significant changes will be needed to adapt electricity utility business models, and pricing structures to meet future needs.

Roundtable participants agreed that, to fully adapt to this role, utilities must develop new ways of pricing the "network services" they provide and of promoting value creation through distributed resource development. However, they expressed differing views about how California's regulated utilities might best adapt to a future with increasing shares of distributed generation resources. Two approaches were discussed:

INCENTIVE REGULATION APPROACH

An "incentive regulation" approach that would allow the utility a more expansive role in managing and, potentially, investing in distributed resources as a tool for reducing costs.

NETWORK UTILITY APPROACH

A "network utility" approach under which the utility would provide highly differentiated price signals to incent customers to provide the highest value energy supply, load management, or ancillary services to the utility system.

Overall, significant changes will be needed to adapt utility's electricity rate structures and business model to meet the needs of the future. Shared understanding among industry stakeholders about system costs and benefits in relation to distributed resources is a critical first step toward finding appropriate solutions.

ABOUT THIS REPORT

The potential proliferation of advanced technologies, combined with rapid improvements in the cost competitiveness of current energy efficiency technologies and distributed resources, especially solar photovoltaics (PV), present unique challenges and opportunities to the traditional utility infrastructure. This can be especially true where distributed generation is concentrated, as in the case of a ZNE community. This report represents a first step to explore the implications for customers, utilities and other providers in this future.

This report identifies and articulates key issues that emerged from analysis completed by RMI and PG&E, together with insights and recommendations that emerged from the roundtable discussion, and defines an "options space" for future analysis. The report and analysis primarily focus on the distributed solar market, which is growing at a strong rate and is nearing penetration levels that will cause noticeable impacts to grid operations and utility business models. However, within the 2020 time horizon described in this report, other distributed resources such as electric vehicles or energy storage could also achieve similar cost declines and increased adoption, resulting in similar needs for reassessing the basic infrastructure, pricing models and business models of the current electricity system.

PROJECT OVERVIEW

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On behalf of PG&E, Rocky Mountain Institute (RMI) organized and facilitated a roundtable of experts to evaluate the potential implications for the utility and its customers of a future business environment characterized by high levels of customer energy efficiency, growing numbers of Zero Net Energy (ZNE) buildings, and increased adoption of distributed generation (largely solar PV) by utility customers. The political and policy environment surrounding distributed resources is highly charged, with strongly held beliefs and assumptions about distributed generation benefits and impediments to customer adoption. At the same time, there are myriad complexities in analyzing the costs and benefits to the utility system of installing these technologies. Costs and benefits will shift over time as markets evolve, penetration rates increase, and new technologies are deployed.

Establishing a common framework for understanding the implications for the utility system of distributed generation (DG), measuring impacts, and aligning rates and policies is a daunting but unavoidable task. The key questions to be addressed include:

> **How will increased penetration of distributed resources and ZNE buildings affect cost and value for the utility and its customers?**
>
> **How could rate structures be modified to enable sustainable, fair, and efficient development of these resources?**
>
> **How might utility business models change?**
>
> **What innovative energy services could be provided by the utility in conjunction with distributed resources and ZNE customers? What is the value of these services to all customers?**

This report identifies and articulates key issues that emerged from analysis completed by RMI and PG&E in support of the expert roundtable, together with insights and recommendations that emerged from the roundtable discussion. This work defines an "options space" for future analysis.

ROUNDTABLE PARTICIPANTS

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Scope & Definitions

An industry standard definition does not presently exist for many of the terms or concepts in this report. For the sake of clarity, we define the terms used in this report as follows:

DER
Distributed Energy Resources

Distributed energy resources are "demand- and supply-side resources that can be deployed throughout an electric distribution system to meet the energy and reliability needs of the customers served by that system. Distributed resources can be installed on either the customer side or the utility side of the meter."[5] This includes generation, managed loads (including electric vehicle charging), energy storage, and other technologies that can provide energy, load management, and ancillary services, such as reserves, voltage control, and reactive power, and black start capabilities.

DG
Distributed Generation

Any electricity generation device connected at the distribution level installed on the customer's side of the meter that is interconnected with the grid, such as distributed solar PV, wind or combined heat and power (internal combustion engines, fuel cells, microturbines, gas turbines).[6]

ZNE
Zero Net Energy

Though California has established goals for achieving Zero Net Energy for all new buildings by 2020 (residential) and 2030 (commercial), the definition of ZNE is still unsettled, especially as it pertains to the parameters for site and energy source. For the purposes of this report, a Zero Net Energy customer is defined as one whose annual electricity consumption and generation net to zero or less. The customer could use any combination of renewable generation, energy efficiency measures, and distributed resources to achieve net zero status.

DRIVERS OF CHANGE

DRIVERS OF CHANGE

Transformative market forces are poised to fundamentally change California's electricity system. While these trends are partly attributable to California energy policies, they are also shaped by changes in technology and economics at the national and global level. For example, across the U.S., supportive policies, combined with rapid technology cost declines and business model innovations (including third-party financing and other financial innovations), have spurred distributed generation, particularly solar photovoltaics (PV), to grow rapidly in recent years. In California, these drivers have resulted in over 1 GW of installed solar PV capacity, representing 48% of the total U.S. solar capacity. Key policy and market drivers are detailed in this section.

POLICY DRIVERS

Legislative and regulatory action to support renewable energy and efficiency is driving a significant shift in the demand for electricity and the generation mix to meet it. Major policy drivers include:

Targets and Mandates Policy-directed targets and mandates include efficiency goals that will reduce load growth, renewable portfolio standards (RPS) that mandate the adoption of clean energy technologies, and environmental regulations that limit the viability of heavily polluting power plants.

Financial Incentives Policymakers have also crafted a suite of financial mechanisms, such as tax incentives that are designed to encourage the continued growth of distributed and renewable generation technologies.

- Federal and state tax incentives and rebates
- Net energy metering policies
- Feed-in tariffs
- Electricity prices and rate structures

TECHNOLOGY MARKET TRENDS

Technological innovation, lead by both global and local markets, enormously expands the range of offerings from traditional and new service providers.

Technology Cost Reductions The costs of renewable and distributed generation technologies have dropped dramatically in the past decade, and are poised for continued reductions. Cost competitiveness significantly accelerates adoption while opening the potential market to even more customers.

Enabling Technologies The market is poised to see further changes with the introduction of smart-grid technologies, electric vehicles, energy storage, and home energy management systems. The deployment and integration of these technologies can provide customers greater control in their interactions with the utility grid, and help utilities manage increasing penetrations of variable renewables and distributed generation.

Service Innovation Innovative distributed generation business models are lowering barriers to adoption and providing new and existing providers with the opportunity to offer new types of integrated energy services in parallel with the regulated utility.

POLICY DRIVERS

California has been a global leader in energy policy since the early 1970s. With the Warren-Alquist Act of 1973, the legislature created the California Energy Commission and established the state's energy policy cornerstone to pursue, "all practicable and cost-effective conservation and improvements in the efficiency of energy use and distribution that offer equivalent or better system reliability." The state's success in aligning profit incentives for utilities to implement and support energy efficiency has helped keep per-capita electricity use flat for the last 30 years and made California the largest energy efficiency market in the country. Today, the combined impact of the energy efficiency, distributed generation, large-scale renewable energy, and environmental regulations affecting thermal power plants is reshaping California's the electricity system (Figure 1).

FIGURE 1
TARGETS AND MANDATES AFFECTING CALIFORNIA'S ELECTRICITY SECTOR (2010–2030)

Current policies and mandates will reshape California's electricity system.

2010

ARB GHG MARKET
AB 32 becomes enforceable in 2012, Cap-and-Trade program emissions obligations begin in 2013

CALIFORNIA SOLAR INITIATIVE
2,550 MW of solar capacity by 2017, 1,940 MW from IOUs

EPA REGULATIONS
US EPA's Clean Air Transport, Mercury and Air Toxic Standards, Coal Combustion Residuals, and New Source Performance Standards rules take effect between 2014 and 2020

2015

ONCE THROUGH COOLING RULES
Will affect 20.4 GW of generation, roughly 35% of CA's fleet. Compliance dates range from 2015-2020

CPUC ENERGY EFFICIENCY GOAL
20% reduction in the business-as-usual forecast for residential electricity consumption by 2015, and 40% by 2020

2020

ZERO NET ENERGY GOALS
All new residential construction will be net zero by 2020

RENEWABLE PORTFOLIO STANDARD
33% by 2020

2025

ARB CHP GOAL
Additional 4,000 MW of CHP by 2020

AB 32
CO_2 emissions reduced to 1990 levels by 2020

GOVERNOR BROWN'S CLEAN ENERGY JOBS PLAN
20,000 MW of renewable energy capacity by 2020 (35,000 MW above existing mandates)

2030

ZERO NET ENERGY GOALS
All new commercial construction will be net zero by 2030.

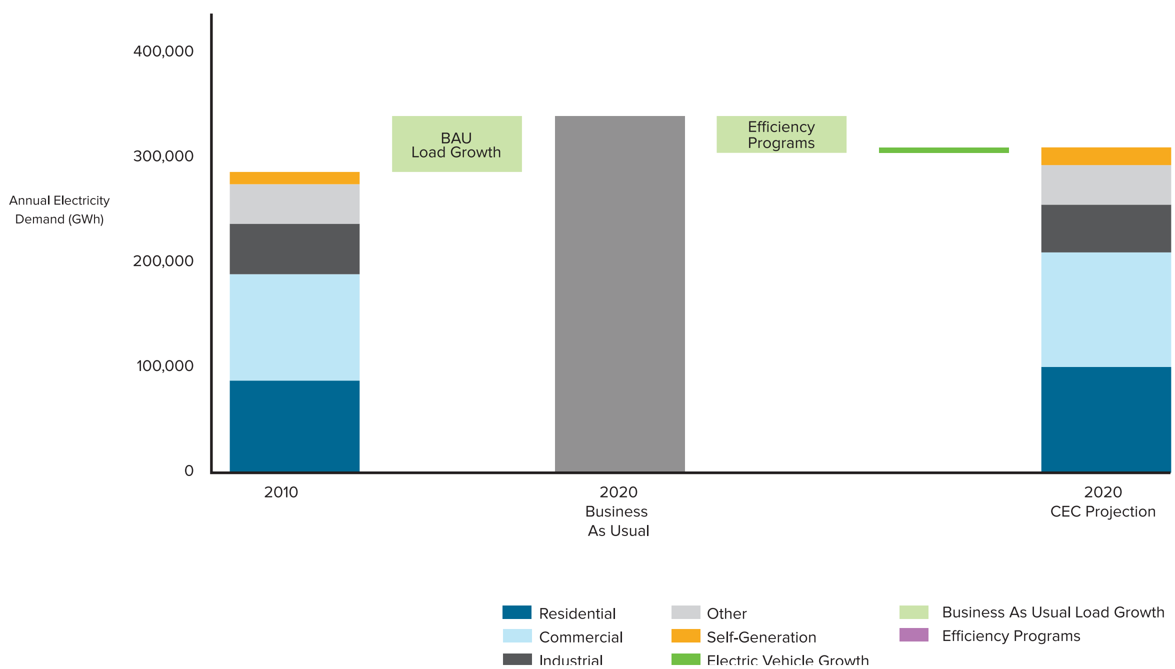
Existing Generation
Renewable Generation
Environment
Efficiency

TARGETS AND MANDATES AFFECTING CALIFORNIA'S ELECTRICITY SECTOR

California's targets and mandates affect both the demand and supply of electricity. On the demand side, California has set some of the most ambitious energy efficiency goals in the nation. By 2020 California is projected to lower annual load growth from ~2% to 1% through customer-funded efficiency programs. Beyond 2020, as part of the CPUC's Big Bold Energy Efficiency Strategies, all residential new construction should be Zero Net Energy (ZNE) by 2020 and all new commercial construction will be ZNE by 2030. These requirements should slow load growth dramatically in these sectors as residents and businesses migrate to new, energy efficient buildings. Together, California's energy efficiency strategies are expected to result in a 9% reduction in electricity demand from the projected "business-as-usual" demand in 2020 (Figure 2).

FIGURE 2
PROJECTED DEMAND FOR ELECTRICITY IN CALIFORNIA

Demand for electricity in California is expected to grow by only 1% annually due to efficiency investments.



Sources and Notes:
California Energy Commission, Preliminary California Energy Demand Forecast 2012-22. August 2011.

Kavalec, Chris, Tom Gorin, Mark Ciminelli, Nicholas Fugate, Asish Gautam, and Glen Sharp. 2011. Preliminary California Energy Demand Forecast 2012-2022. CEC-200-2011-011-SD.
Scenario Descriptions: p. 28
Self Generation Stats: p. 34

Assumptions: "Low Demand" scenario, included uncommitted savings, assumed sector totals did not include demand met by DG. BAU: Assumed no EE savings, no EV growth, and no addt'l self generation, (modeled BAU by backsolving, given EE as a % of consumption)

On the supply side, a range of policies encouraging large-scale renewables and distributed generation coupled with new restrictions on thermal power plants (Table 1) will reshape the electric supply mix. Between 2010 and 2020, these policies will at minimum require a 250% increase in installed non-hydro renewable capacity, and the retirement of 25% of existing natural gas-fired generation capacity (Figure 3).

TABLE 1
POLICIES AFFECTING ELECTRICITY SUPPLY MIX IN CALIFORNIA

FOSSIL FUELED OR THERMAL GENERATION

ONCE THROUGH COOLING (OTC) POLICY

To protect the state's marine environments, in 2010 the California State Water Resources Control Board (SWRCB) established regulations restricting the use of coastal and estuarine water for power plant cooling, affecting 20.4 GW of generation capacity (30% of CA's fleet). From 2015 to 2020, 12 GW of natural-gas-fired power plants are expected to retire,rather than retrofit to comply with the new rules.

GLOBAL WARMING SOLUTIONS ACT (AB 32)

California's legislature signed AB 32 in 2006, establishing goals to reduce CO_2 emissions to 1990 levels by 2020 and to 20% of 1990 levels by 2050. To enforce this law the California Air Resources Board (CARB) plans to institute a Cap-and-Trade Program, which will limit GHG emissions and create a market for tradable allowances. Emissions obligations for electric utilities begin in 2013.

ENVIRONMENTAL PROTECTION AGENCY (EPA) REGULATIONS

The North American Electric Reliability Corporation anticipates that the EPA's enforcement of Clean Air Act regulations will significantly accelerate the retirement of generation capacity as they take effect between 2014 and 2020.

RENEWABLES, DISTRIBUTED GENERATION

RENEWABLE PORTFOLIO STANDARD (RPS)

California's RPS, enacted in 2002 and subsequently updated, is the single greatest driver of the changing resource mix in the state. It sets forth a strict timeline, mandating that 33% of utilities' annual electric sales be procured from renewable resources by 2020.

TECHNOLOGY-SPECIFIC GOALS

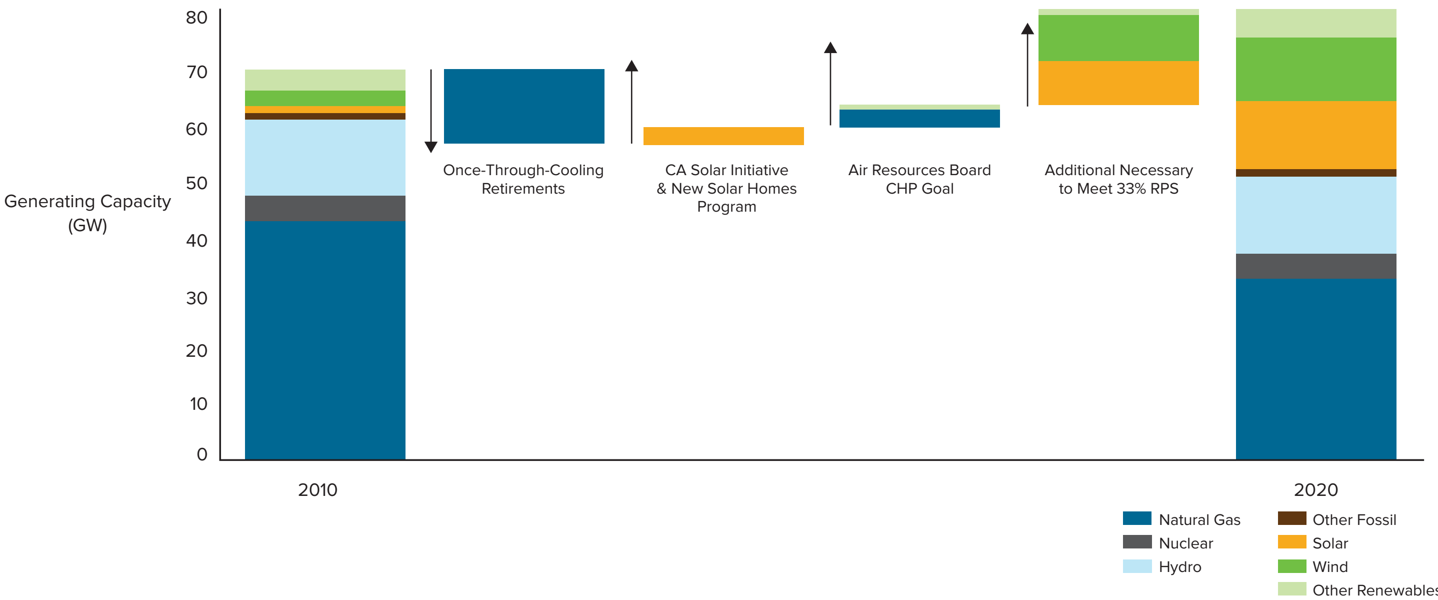
The Go Solar California campaign aims to install 3 GW of solar energy systems by 2017 through the California Solar Initiative (CSI), the New Solar Homes Partnership, and various POU programs. Additionally, to meet AB 32, CARB set the ambitious goal of adding 4,000 MW of new CHP capacity by 2020 — nearly a 50% increase.

GOVERNOR BROWN'S CLEAN ENERGY JOBS PLAN IN 2010

Governor Brown called for 20 GW of new renewable energy capacity by 2020, including 12 GW of DG and 8 GW of utility-scale capacity. This goal is a 3.5 GW increase over existing mandates and would more than triple the non-hydro renewable capacity on the system. The plan also expands CARB's CHP goal, calling for 6.5 GW of new cogeneration capacity by 2030.

FIGURE 3
PROJECTED GENERATING CAPACITY FOR CALIFORNIA (2010–2020)

The supply mix will include significant contributions from renewables at the expense of thermal generation.



2010 Generator Capacity California Energy Commission. Database of California Power Plants. http://energyalmanac.ca.gov/powerplants/POWER_PLANTS.XLS. 2011.

2010 Behind-the-Meter Capacity 2011. Staff Draft Report on Renewable Power in California: Status and Issues. California Energy Commission, August 2011, Publication No. CEC 150 2011 002.

Expected OTC Retirements Vidaver, David, Mike Ringer, Michael Nyberg, Darryl Metz, Connie Leni. 2009. The Role of Aging and Once-Through-Cooled Power Plants in California An Update. California Energy Commission. CEC-200-2009-018.
CARB CHP Goals Darrow, Ken, Bruce Hedman, Anne Hampson. 2009. Combined Heat and Power Market Assessment. California Energy Commission, PIER Program. CEC 500 2009 094 D.
CSI/NSHP Additions California Public Utilities Commission. About the California Solar Initiative. http://www.cpuc.ca.gov/puc/energy/solar/aboutsolar.htm. 2009.
2020 Renewables Capacity California Independent Systems Operator. 2011 Annual State of the Grid. 2011.

FINANCIAL INCENTIVES

In addition to technology or efficiency targets, which are often used to "push" markets, financial incentives, such as tax incentives and rebates, create market "pull" for the growth of renewable and efficiency resources by reducing the costs to potential buyers. By substantially reducing the cost to install these systems, these subsidies have resulted in more attractive investment opportunities and significantly greater demand. Beyond ensuring that the development of distributed generation is economically viable for the adopter at the point of initial capital investment, additional policies and regulations within the electricity sector—such as net-metering policies, feed-in tariffs, and the relative cost of electricity itself—significantly affect the viability of distributed and/or renewable investments.

TAX INCENTIVES AND REBATES

Funding comes primarily from the federal, state or local governments, and utilities. The availability of incentives differs based on technology, system size, and type of owner. Benefits may be tied to system capacity ($/kW), system production ($/kWh), or investment cost, and are typically distributed as either tax benefits or rebates.

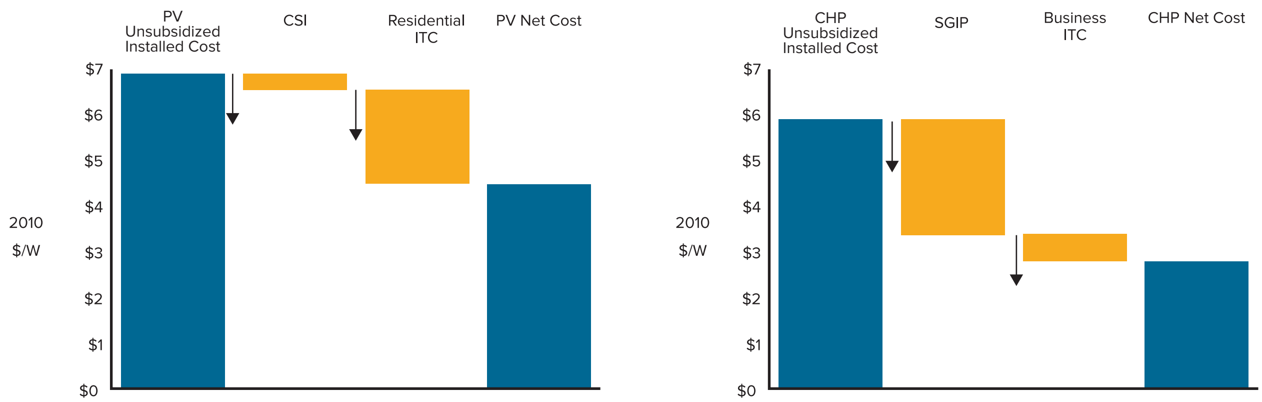
To illustrate the effect of these incentives on the economics of a renewable energy investment, Figure 4 illustrates the annual and cumulative savings that result from the installation of a residential 4 kW PV system or a commercial 500 kW biogas internal combustion engine CHP system. The California Solar Initiative (CSI) rebate and federal residential investment tax credit (ITC) combine to reduce the capital cost of the PV system by 35%, while the Self Generation Incentive Program (SGIP) rebate and federal business ITC cut the cost to install the CHP system in half.

TABLE 2
SELECTED REBATES AND TAX INCENTIVES AFFECTING CALIFORNIA'S SUPPLY MIX

REBATES	California Solar Initiative (CSI)	The California Solar Initiative (CSI) provides electric customer-funded cash rebates to PV owners. Rebates decline as installed capacity increases until a self-sustaining solar market is created. Thus far, $1.1 billion has been provided for over 600 MW of PV. Early program rebates of $2.50/W dropped system prices 25% and jump-started the market. At present, CSI rebates have dropped to as low as $0.35-$0.20/W, and are no longer the primary determinant in whether a system is economic.
	California Self Generation Incentive Program (SGIP)	The California Self Generation Incentive Program (SGIP) provides rebates to distributed wind, CHP, fuel cell, and advanced storage technology system owners. The SGIP program focuses on high-cost, recently commercialized technologies, has a $75 million annual budget, and provides $1.50-4.50/W incentives. 350 MW have been installed under this program since 2000. Recent policy changes will reduce incentives beginning in 2011, and shift to a mix of up-front and performance-based incentives to reward performance, not just installation. The CHP rebates are based in part on efficiency.
TAX INCENTIVES	Federal Tax Credits	Provides a personal investment tax credit of 30% of installed system capital cost and a corporate investment tax credit equal to either 10% or 30% of system cost depending on the technology.
	CA AB 1451	Allows for the property tax exemption of 100% of the increase in property value resulting from the installation of a PV system.

FIGURE 4
IMPACT OF CURRENT INCENTIVES

Current incentives reduce the upfront cost of a residential solar PV system by 35% and the upfront cost of a commercial CHP system by 50%.



Source: CHP system is a 500 kW biogas-fueled ICE, cost data from ITRON report for CPUC:http://www.cpuc.ca.gov/NR/rdonlyres/2EB97E1C-348C-4CC4-A3A5-D417B4DDD58F/0/SGIP_CE_Report_Final.pdf | SGIP data from PG&E: http://www.pge.com/mybusiness/energysavingsrebates/selfgenerationincentive/equipmenteligibility.shtml | ITC data from DSIRE

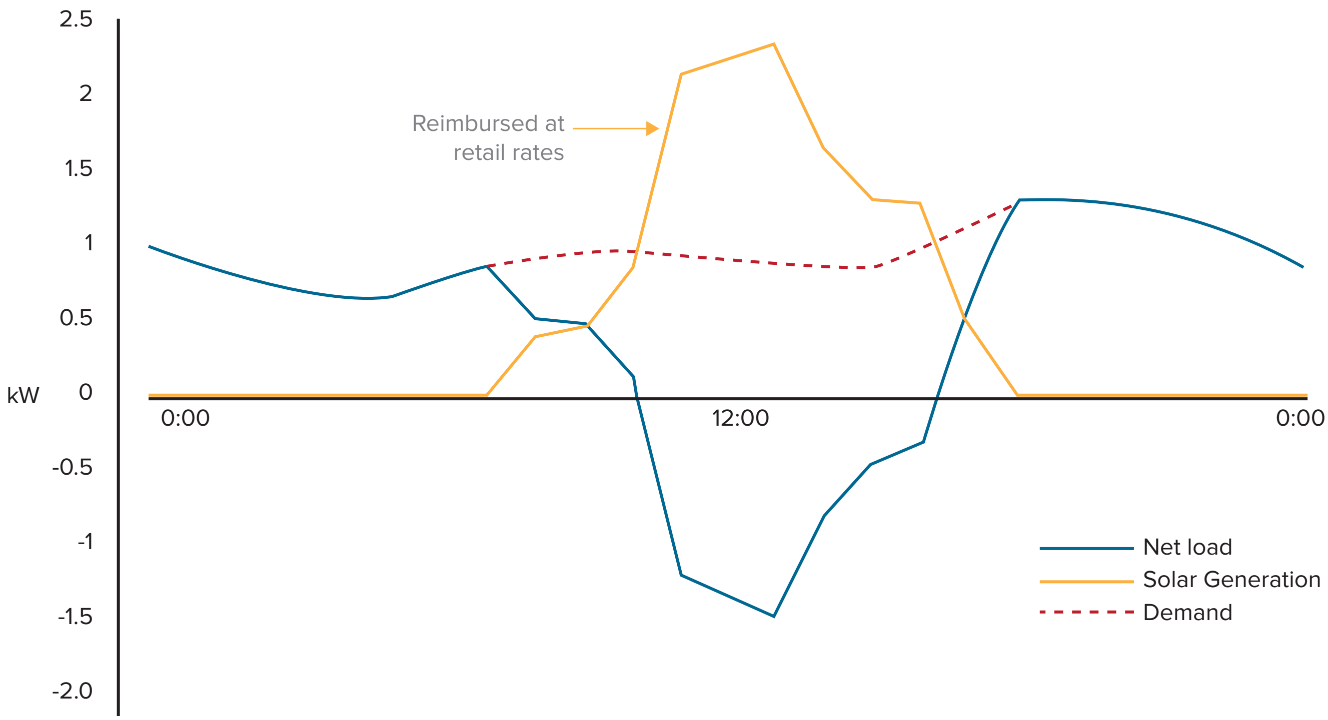
NET ENERGY METERING

To encourage the installation of distributed generation, net energy metering (NEM) programs credit customers for the electricity they export, typically at retail rates.[7] By "netting" the customer's bill, full retail NEM provides the customer the retail value for electricity exported to the grid, which can significantly increase the value of self-generation to the customer (Figure 5). The simplicity of full retail NEM, or "running the meter backward," has led to the adoption of NEM in 43 states and the District of Columbia.

Recent legislation expanded retail net metering in California to all renewables up to 1 MW that are sized to a customer's annual load. California regulators have capped the total generation capacity participating in NEM programs at 5% of peak load. If installed PV capacity in California continues on its current growth trajectory (a 46% per year average over the last two years) capacity will approach the NEM cap in approximately 2014 (Figure 6). In addition, they have recently begun to extend NEM eligibility beyond single contiguous properties by allowing virtual net energy metering (VNEM), which in some instances enables customers to participate in off-site and/or group-owned projects. California has carefully restricted VNEM to multi-tenant and multi-meter properties with a single point of interconnection with the distribution system.

FIGURE 5
ILLUSTRATIVE EXAMPLE OF RETAIL NET ENERGY METERING FOR RESIDENTIAL CUSTOMER WITH SOLAR PV

Under retail NEM, a solar customer receives full retail credit for excess generation exported to the grid.

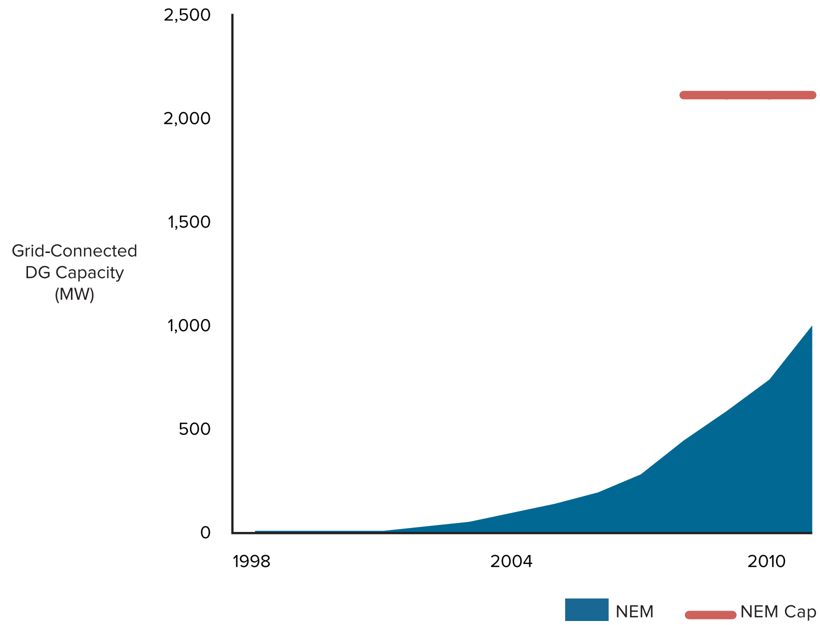


FEED-IN TARIFFS AND RENEWABLE AUCTIONS

While NEM programs incent distributed generation on the customer side of the meter, alternative mechanisms, such as feed-in-tariffs (FITs) and auctions, allow utilities to procure power from distributed renewable generation. These mechanisms, intended to bridge the gap between incentives for DG on the customer side of the meter and utility-scale projects, will help to meet California's RPS, while also creating additional market growth in the state. FITs allow regulators to encourage small-scale renewable development using predefined PPA terms with differentiated rates, meaning FIT rates may vary depending on technology, siting, or other attributes.[8] California recently extended FIT eligibility to renewable generators up to 3 MW capacity, with a cap of 750 MW.[9]

FIGURE 6
INSTALLED DG CAPACITY IN CALIFORNIA

Installed DG capacity in California has grown exponentially, approaching the program cap of 5% peak load. If installed PV capacity in California continues on its current growth trajectory (38% per year average over the last two years) capacity will approach the NEM cap in approximately 2014.



Source: California Solar Initiative Data, accessed Feb 28th, 2011

To complement the state's FIT offering, the CPUC created the Renewable Auction Mechanism (RAM), an innovative program that allows IOUs in the state to use auctions to procure contracts with larger renewable projects (≤ 20 MW). The RAM establishes regulatory certainty for developers and utilities, and also protects electricity customers by ensuring that utilities secure the lowest-cost projects available through competitive bidding — it will result in the addition of approximately 1 GW of contracted renewable generation capacity to California's grid by 2013.

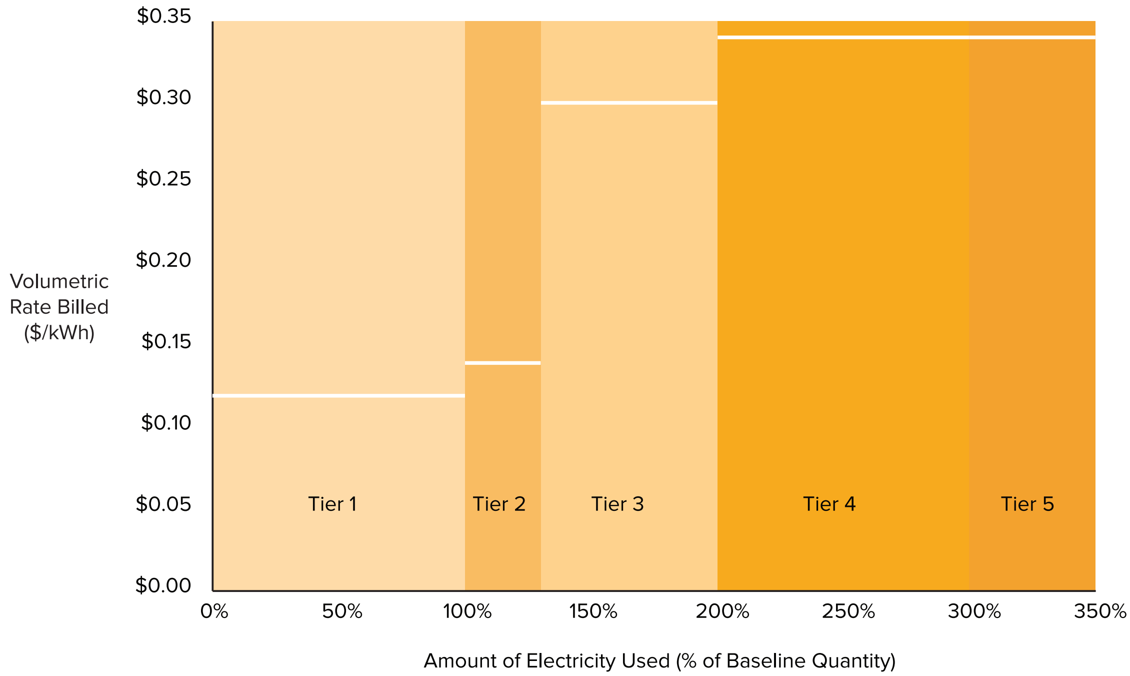
CALIFORNIA ELECTRICITY RATES

California has a tiered rate structure for residential customers with the primary goal of encouraging energy efficiency. That is, the price for electricity (cost per kWh) increases as the amount of electricity a customer uses increases over a billing period (Figure 6). Thus, reductions in electricity consumption will be valued at the marginal tiered rate, and higher electricity consumers will have a larger efficiency incentive. Since the reduction of utility-generated electricity via distributed generation looks economically equivalent to an efficiency investment, California's tiered rate structure also serves to encourage distributed energy resources.

FIGURE 7

PG&E'S CURRENT RESIDENTIAL TIERED RATE STRUCTURE (JANUARY 2012)

Residential customers, whose cumulative monthly usage rises above 150% of their baseline value (as defined for each climate zone), see their marginal electricity rate more than double.



Source: PG&E E-1 Tariff, effective Jan 25, 2012

In response to the 2000-01 energy crisis, the California Legislature froze lower-tier rates (Tiers 1 and 2) as a means to protect some customers from the impact of crises-related cost increases. Therefore, all rate increases over the past decade have fallen to the top tiers: 3, 4 and 5. In 2010, legislators voted to allow the lower tiers to increase by 3-5% annually; however, this will relieve only some of the pressure on the upper tiers.

The restrictions on increasing lower-tier rates have resulted in a significant disparity among rate tiers, in which upper tier rates are three to four times as high as lower tier rates. For example, the average upper-tier rate is currently $0.33 per kWh—and was recently as high as $0.49 per kWh, compared to the average lower-tier rate of $0.12 per kWh. Comparing these rates to the current levelized cost of solar PV for a residential customer, which is estimated to be $0.25 to $0.29 per kWh, it is apparent that customers whose usage reaches the upper tiers have a strong incentive to install solar PV.

TECHNOLOGY MARKET TRENDS

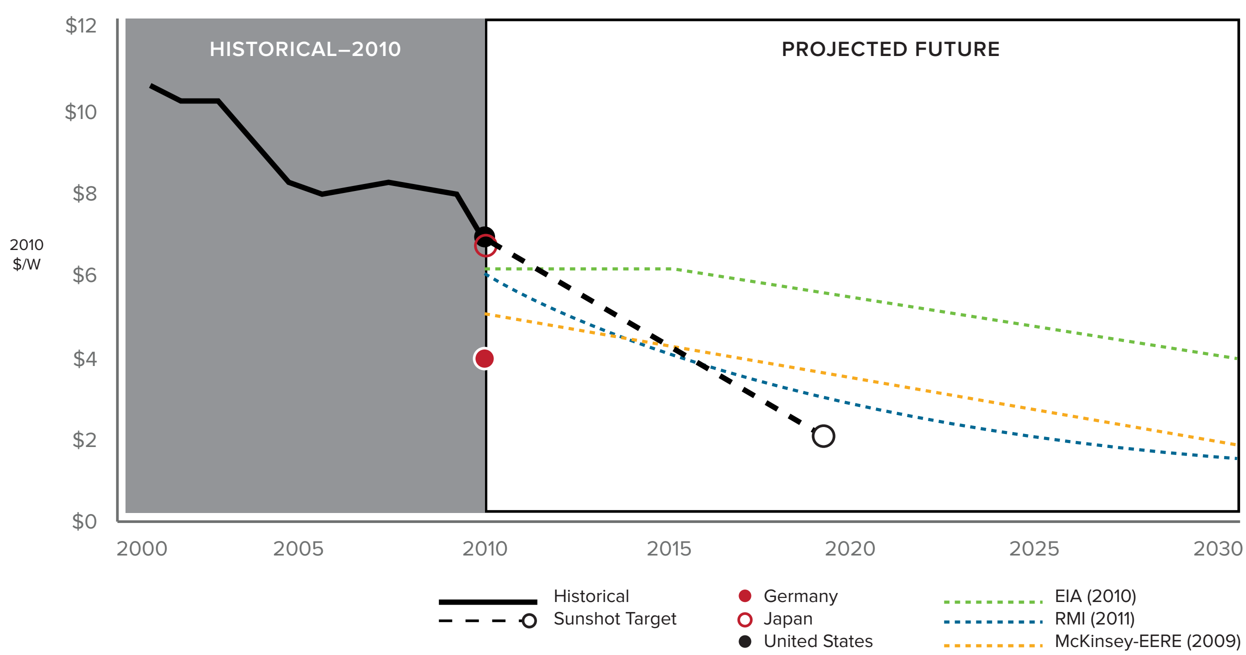
TECHNOLOGY COST REDUCTIONS

Experience, scale, and technological innovation continue to drive down the cost of emerging and rapidly maturing power generation technologies across global markets. The costs of renewable and distributed technologies have dropped dramatically in the past decade and are poised for continued reductions. For example, since the 1970s, the cost of solar module production has declined by 50% for every tenfold increase in production. Recently, the cost reduction trend has accelerated as global module prices fell by more than half from 2008 to 2011.[10]

Cost competitiveness significantly accelerates adoption while opening the potential market to more customers—without additional incentives. The industry has support in its cost cutting efforts: U.S. Department of Energy's SunShot Initiative, which sets the goal of making solar energy systems cost competitive with wholesale power by 2020 (Figure 8).

FIGURE 8
HISTORICAL AND PROJECTED SOLAR PV COSTS

Solar costs have declined rapidly and many forecasts expect that decline will continue.



HISTORICAL DATA: BARBOSE G, WISER R, DARGHOUTH N. 2011. TRACKING THE SUN IV. LBNL. I COST PROJECTIONS: RMI 2010. ACHIEVING LOW-COST SOLAR PV; EIA 2009. DECEMBER SOLAR PHOTOVOLTAIC CELL/MODULE MANUFACTURING ACTIVITIES 2008.I WASHINGTON, D.C.; EERE 2010. MAY 28 SOLAR VISION STUDY - DRAFT; TRACKING THE SUN IV.

FIGURE 9
PROJECTED LITHIUM BATTERY COSTS (2010–2020)

Costs of lithium-ion batteries are projected to decline significantly by 2020.

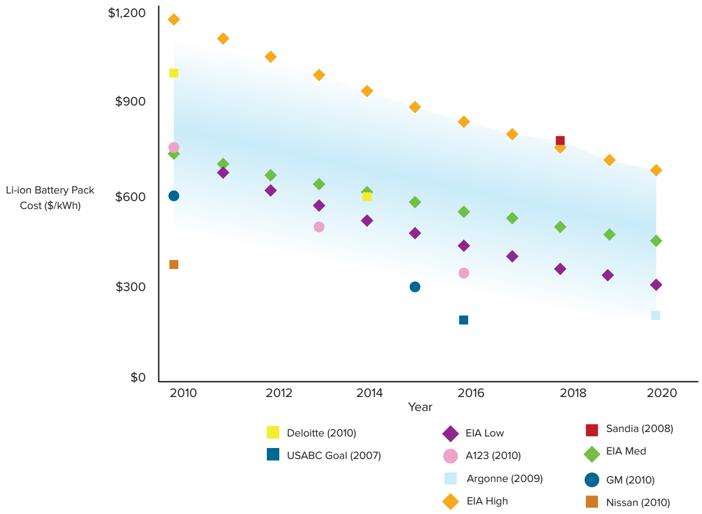
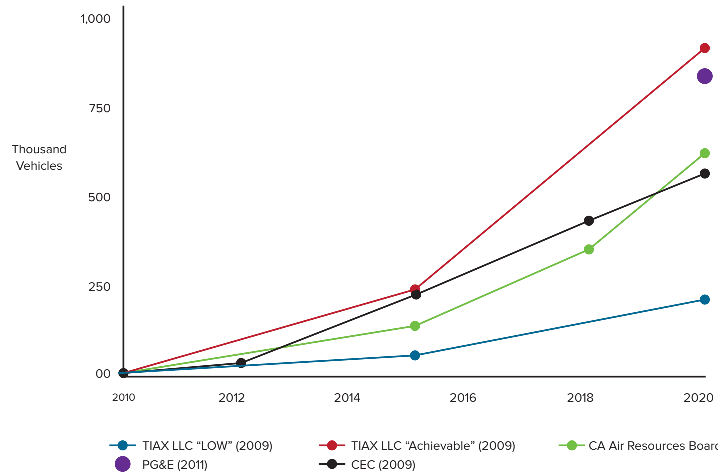


FIGURE 10
PROJECTED ELECTRIC VEHICLES IN PG&E'S TERRITORY

Electric vehicles in PG&E's service territory could number more than half a million by 2020.



Meanwhile, a recent surge of interest and investment has led to optimism that new forms of energy storage will provide increasingly competitive options for managing electricity supply within the next decade (Figure 9). Projected growth in electric vehicle (EV) adoption will add a fleet of regularly connected distributed batteries to the grid. In the future, utilities and grid operators may be able to take advantage of these storage devices to provide the added flexibility for the electricity grid. (Figure 10).

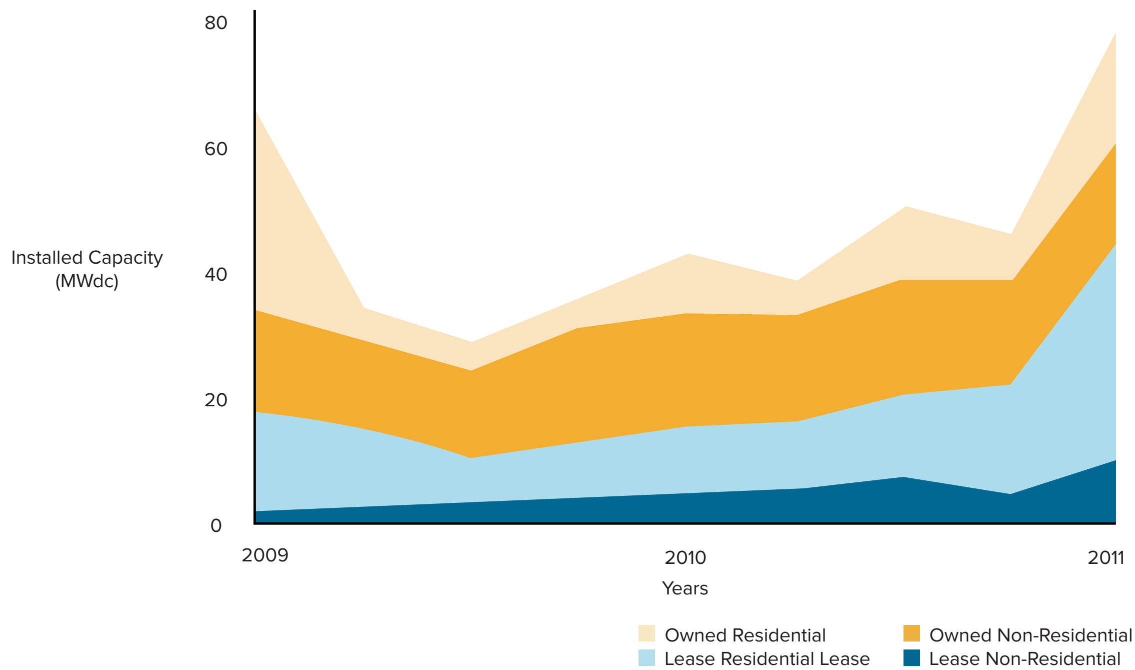
ENABLING TECHNOLOGIES

Information technology is driving remarkable innovations in how electricity can be monitored, controlled, and delivered throughout the grid. Advanced grid infrastructure, including smart grid technologies, could further open the market for distributed energy resources by enhancing distribution network operations and management, potentially mitigating some of today's technological barriers to higher penetrations of distributed generation and storage assets.

Grid modernization is already underway. Seventy-four percent of California IOU customers currently have advanced metering infrastructure (AMI) installed. In four years this technology will be installed in over 50% of U.S. households.[11] Supervisory control and data acquisition (SCADA) systems and AMI can provide high-resolution network data to system operators, which can enable dynamic pricing and demand response, thereby providing greater demand flexibility and creating opportunities for customers to contribute to system balancing. Meanwhile, new energy management systems for homes and businesses can provide consumers with better tools and fewer hassles to manage their electric loads and minimize their bills.

FIGURE 11
CALIFORNIA PV INSTALLATION (2009–2011)

Third-party owned projects now account for 57% of the California PV market and growing.



SERVICE AND BUSINESS MODEL INNOVATION

Innovative ownership and financing arrangements are lowering the barrier to entry for hosts in the development of renewable distributed generation projects. Leveraging government tax incentives, many third party entities have proven particularly creative as they shift away from the customer-ownership model by building systems supported by customer lease or power purchase agreements (PPAs). Like a mortgage, lease agreements and PPAs allow system costs to be repaid by users over time, and require little or no money down. Customers can be cash-flow positive immediately, dramatically reducing the investment hurdle to go solar. Third-party-owned projects now account for 57% of the market in California (Figure 11). Similarly, in Colorado, the market share of residential customers leasing systems has grown to 57% in the 18 months since the state authorized leasing structures.

The availability of zero- or low-money down leases has had a dramatic impact, increasing the pace of solar adoption in existing customer segments and opening up markets not available to system ownership. An NREL study of Los Angeles-area solar project data found that leased systems increased customer demand for residential PV systems by up to 28% from 2007 to 2011 in Los Angeles and Orange counties. The success has attracted capital: The pool of financing available to fund leases has grown from $105 M in 2008 to over $1.8 B in 2010.

Additionally, developers with little tax liability have used sale-leasebacks and partnership flips to enable the development of projects that would otherwise have been uneconomic. These ownership arrangements involve structuring transactions where investors with greater tax appetite assume ownership of a system, maximizing the value of available government incentives.

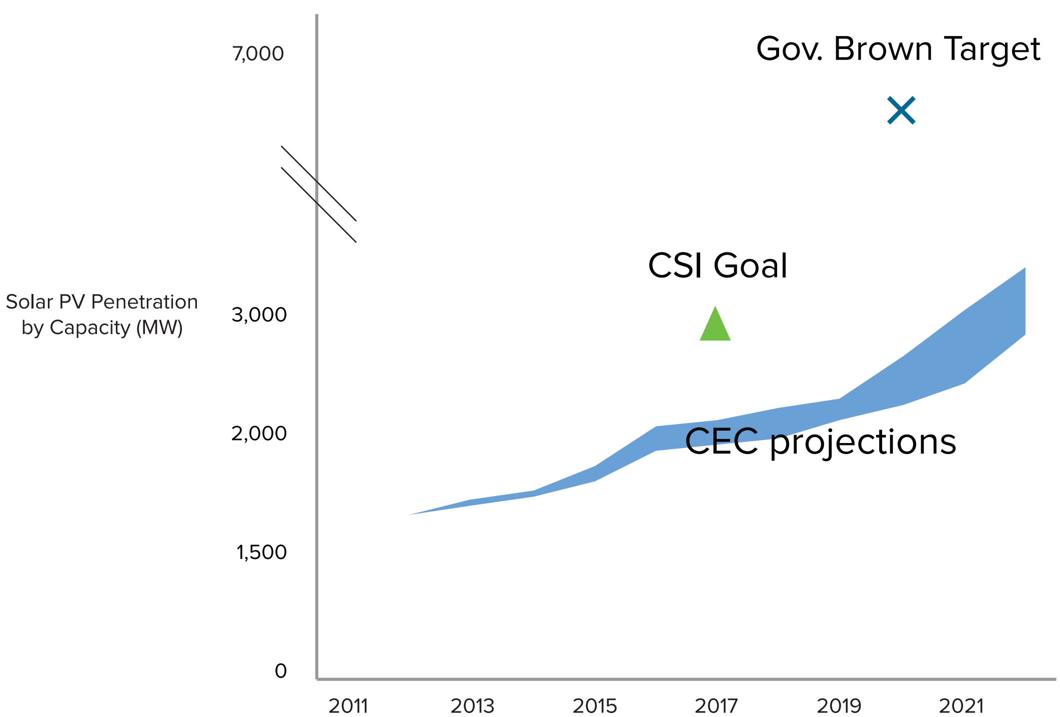
CUMULATIVE IMPACT: FORECASTED GROWTH

The net impact of technological innovation, cost reductions, and an encouraging policy environment is rapidly expanding the range of options for onsite generation and management of electricity. Conservative forecasts by the California Energy Commission of statewide solar

FIGURE 12

RANGE OF PROJECTED RESIDENTIAL AND COMMERCIAL PV ADOPTION ESTIMATES IN CALIFORNIA (2011–2022)

Solar PV adoption over the next decade is projected to increase from less than 1,000 MW to between 2,900 and 6,500 MW by 2022. Solar PV adoption over the next decade could increase significantly in PG&E's territory.



Governor Brown targets 6,500 MW by 2020.

California Energy Commission (CEC) projections estimate that commercial and residential solar PV will account for at least 2,900 to 3,500 MW of capacity by 2022.

The California Solar Initiative (CSI) targets 3,000 MW by 2017.

Source: California Energy Commission, Preliminary California Energy Demand Forecast 2012-22. August 2011.

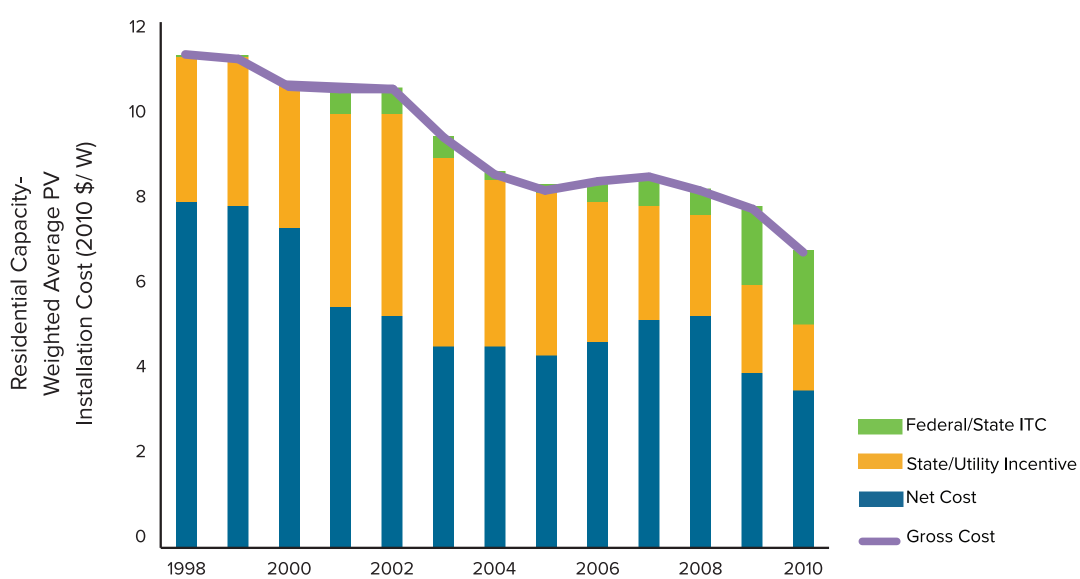
adoption project rooftop PV supplying 5% of total energy needs in 2022—assuming that all solar adoption would be behind or attached to the customer's meter. Assuming no adaptive response in rate policy by regulators, upper-tier residential rates in 2017 could continue to climb, providing an additional incentive for solar adoption (Figure 12). To the extent that California enables virtual net energy metering where the solar system can be located at a significant distance from the customer's load, the penetration would be expected to be much higher.

Several interrelated factors will likely sustain growth in the distributed solar PV market even after current subsidies sunset in 2017. First, the CSI program was designed with subsidies that step down as the market expands past discrete installed capacity benchmarks. As the market grows and solar installed costs drop, the state pays a smaller share of the cost of new installations. The state CSI incentives now have a minimal impact on system costs. The current CSI level for residential systems in PG&E's territory is $.25 per watt, which results in a 3%[12] cost reduction on the current average system. Second, conservatively projected solar cost reductions over the next six years will make up for the expiration of the 30% Federal ITC so that the net levelized cost of energy (LCOE[13] to the customer remains the same in 2017 as it is today (Figure 13). Third, today's solar LCOE, which is estimated to be $0.25 to $0.29 per kWh,[14] is competitive with Tier 3 and 4 rates, supporting the strong growth the solar market has experienced.

FIGURE 13

GROSS AND NET RESIDENTIAL SOLAR PV INSTALLED COST IN CALIFORNIA (1998–2010)

Solar cost declines should offset the future impact of the sunsetting of state and federal subsidies.



Source: LBNL, Tracking the Sun IV. September 2011

POTENTIAL CHALLENGES

POTENTIAL CHALLENGES

Projected growth in the distributed solar market will provide more choices to customers that are more competitive and environmentally benign while at the same time raising new operational and cost recovery challenges for the regulated electric utility. The following section describes these potential challenges in detail.

UNPACKING THE CHALLENGE

DG or ZNE customers rely on the grid to meet their needs for power at various times, as well as to export power when DG output exceeds onsite use. Grid power could either be used to provide supplemental power or backup for outages (scheduled or unscheduled) affecting distributed generation. The timing and magnitude of these customers' needs for grid service will differ depending upon the sizing and characteristics of the customer's on-site technologies and demand and load profile.

FIGURE 14
A DG CUSTOMER RECEIVES LESS ENERGY FROM THE UTILITY BUT STILL RELIES ON THE GRID FOR POWER SUPPLY AND NETWORK SERVICES TO EXPORT POWER TO THE GRID

In this illustrative example (Figure 14), a traditional full service customer has a typical daily residential afternoon peak and a relatively consistent weekly demand for grid power. A DG customer with the same demand for power over the course of the day has her power met by onsite PV power. During the day, when she isn't home and solar output is at its greatest, she exports the power to the grid for her utility to reimburse her at retail rates. Although the total amount of energy demanded from the grid is smaller than the demand of the traditional customer, the DG customer's demand profile has changed substantially. There are steeper peaks and valleys that the grid will have to meet, especially if many of the DG customer's neighbors also decide to install solar PV on their roofs. The ZNE customer, who wanted to produce as much renewable power onsite as he consumes from the grid, pursued energy efficiency before adding a large PV array to his roof. The PV power completely offsets his energy use annually. Therefore, on smaller timescales, such as hours, day and weeks, the amount that he is importing or exporting vastly fluctuates. In fact, the ZNE customer's peak demand on the grid could be when he is exporting power. These phenomena represent a fundamental shift in the formerly one-way power system from both a technical and institutional perspective.

Under existing rate structures, typical residential customers are charged a bundled volumetric rate. These bundled rates are designed to reflect estimated total costs incurred by the utility to serve customers, including the variable and fixed costs required to generate and deliver electricity. These rate structures have the virtue of simplicity, and they provide strong incentives for energy efficiency, but they do not allocate fixed and variable costs to separate charges (see Traditional Electricity Rates text box). Therefore, under the volumetric rate structure, energy generated on the customer side of the meter displaces grid power at the full retail rate. Further, under retail net metering, customer generation exported to the grid is also credited at full retail rates. DG customers on volumetric rates who export as much or more generation as they consume from the grid can reduce their bill to zero through the power exported to the grid. Further, many customers on time-of-use (TOU) rates can actually zero out their bills—excluding minimum charges—while remaining net consumers of electricity from the grid.

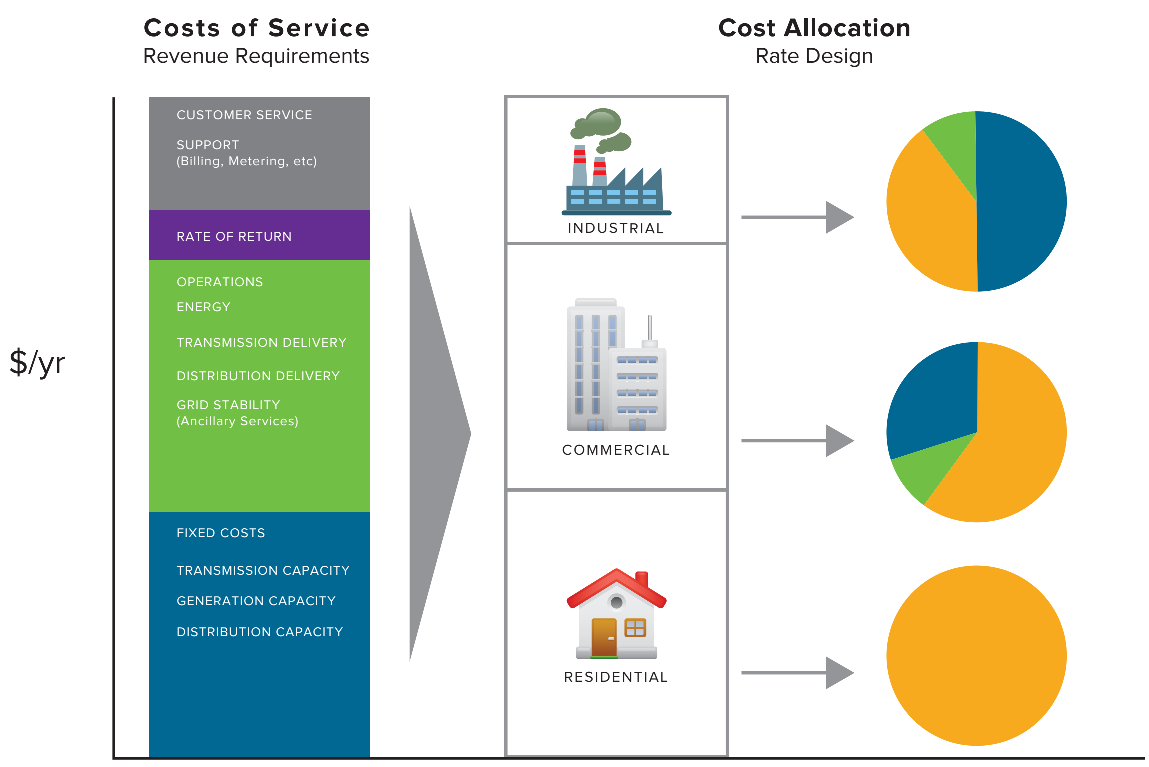
TRADITIONAL ELECTRICITY RATES

The traditional costs of service are fixed and variable. Variable costs change as a function of volume. For example, the variable cost of generating electricity includes the change in costs associated with the production of an incremental kilowatt-hour—primarily fuel and variable generator operations and maintenance costs. Fixed costs include all capital investments in capacity, including generation, transmission and distribution, billing systems, and customer service call centers required to supply electricity and service each account. Fixed costs are a function of not only the highest level of electricity demanded by customers, but also the magnitude and timing of that demand. If the customer's electricity demand adds to the amount of generation, transmission, and distribution capacity the utility must build and maintain, then this adds to what are generally considered to be the utility's fixed costs.

Traditionally, utilities have used "bundled" rates for estimating charges for smaller customers, while using more complex pricing structures for larger customers. For example, residential and small business customers are typically charged a single volumetric rate ($/kWh) and possibly a customer charge, while larger commercial and industrial customers may see two or three charges, such a volumetric energy charge combined with a demand and/or customer charge. The distinctions in rate structures among customer classes are driven by the historical premise that smaller customers with smaller bills have less motivation, necessary sophistication or the needed tools to respond to complex price signals.

FIGURE 15

CONVENTIONALLY, UTILITIES HAVE BUNDLED SERVICE COSTS, WHICH ARE RE-ALLOCATED BY RATE DESIGN



ENERGY CHARGE
kWh-based generation costs (e.g., fuel, wholesale electricity)

DEMAND CHARGE
Costs of the generation, transmission and distribution capacity to serve peak demand

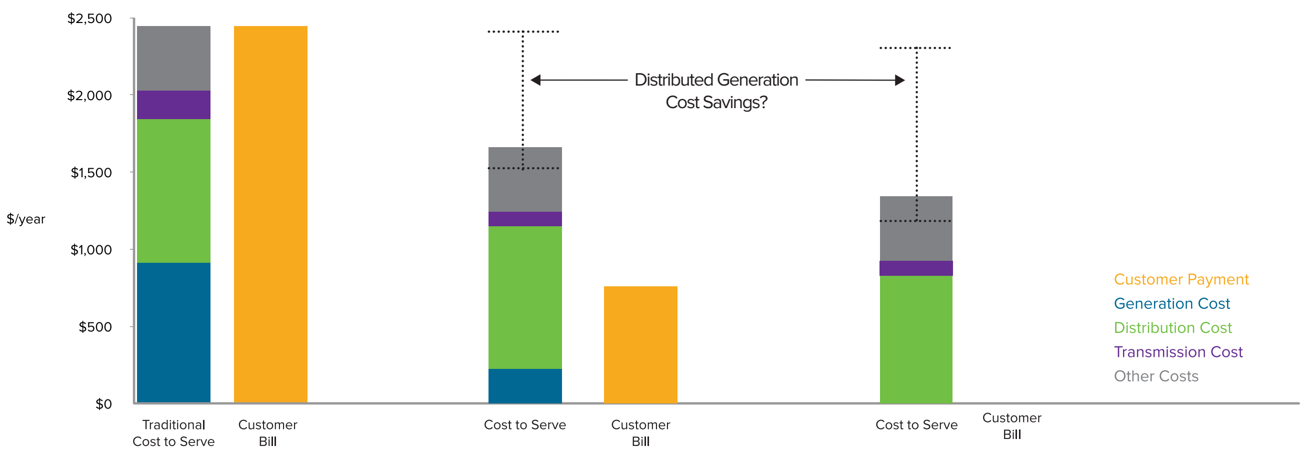
CUSTOMER CHARGE
Flat monthly charge covering fixed costs of servicing customer regardless of use (e.g., billing, customer service)

Figure 16 shows a traditional full service utility customer without a DG system and pays the utility $2,445 a year. Her payment covers the fixed and variable costs to provide generation, transmission, distribution and other services, such as billing and energy efficiency. If that customer were to generate 50% of annual energy needs from a rooftop PV system, she could reduce her annual bill to $757 (since they offset higher tier usage first). If she generated 100% of her annual electricity needs from a PV system, becoming a zero net energy customer, then she could reduce her average utility bill to effectively $0. However, the utility still incurs costs to serve a zero net energy customer who is exporting and importing power via the distribution system. If these costs are not outweighed by the benefits associated with the DG, such as the value of displaced energy or avoided distributed system costs, the under-collection of the cost to serve DG customers will result in a cost shift to other customers on the grid in the form of higher rates.

FIGURE 16

RESIDENTIAL NET ENERGY METERING UNDER TIERED, VOLUMETRIC RATES

Under existing rate structures, the cost of providing service to DG or ZNE customers may not be recovered, or the value created by DG not recognized.



ANNUAL BILL **$2,445** → **$757** → **$0**

Traditional, Full Service Customer

This customer, whose load profile is average for the type of residential customer likely to install DG under NEM, pays for her electricity on PG&E's E-1S schedule. On average, the utility fully recovers its costs.

Distributed Generation Customer

The customer installs a PV system that meets part of her annual energy use. Under current rates, the utility is likely to under-recover its costs to serve such a customer, but the results depend on usage, load shapes, and other factors.

Zero Net Energy Customer

The customer installs a PV system that meets ALL of her annual energy use. The utility receives no revenue even though the customer still uses to the utility's network as a battery.

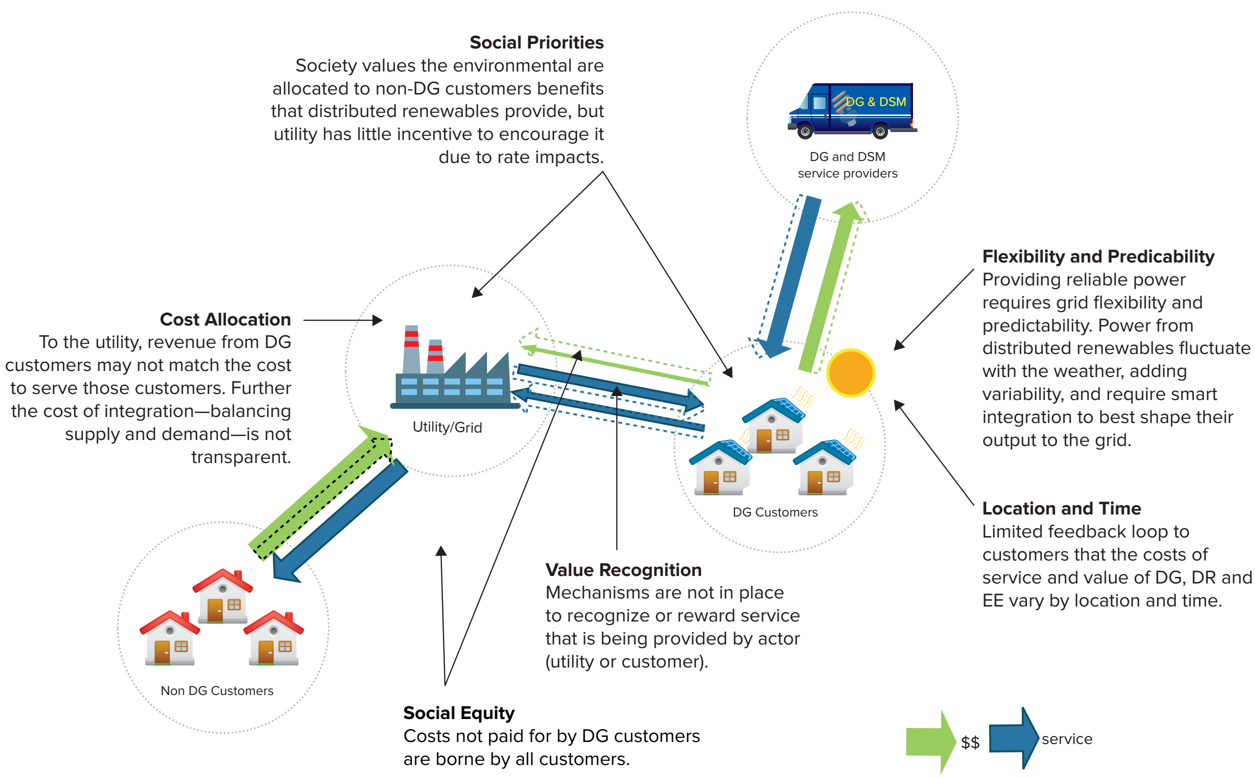
IMPLICATIONS

A disconnect between service and value flows creates multiple misalignments along economic, social and technical dimensions that may result in higher system costs and unrealized benefits. These misalignments can occur across several dimensions:

> **Cost Allocation** The cost or value of the energy, capacity, delivery, and grid support services that sustain the electricity system are not being appropriately priced or allocated, distorting the value of customer-side energy and infrastructure.
>
> **Equity** A misallocation of who is paying and who is benefiting creates significant equity issues between NEM customers and non-NEM customers.
>
> **Operations** At the distribution level, the grid's operational needs are not valued, such as the importance of reliability, safety, flexibility, predictability, where and when service is needed or the cost of energy at the distribution feeder level.

FIGURE 17
MISALIGNMENTS ALONG MULTIPLE DIMENSIONS

Multiple misalignments along economic, social and technical dimensions that may result in higher system costs and unrealized benefits.



COST ALLOCATION

As customer-generators offset their energy use, they are reimbursed at their retail volumetric rate, which includes the fixed costs that the utility incurs on their behalf. If these costs are not outweighed or offset by the benefits from the customer generator, the result is revenue from these customers that declines to a greater degree than the cost to serve them; essentially, current volumetric rates do not appropriately charge these customers for the service that they receive from the utility, and may not appropriately credit them for the services that they provide to the utility. A further misalignment is created between the large number of customers paying volumetric rates and the fixed-cost nature of the utility's cost of service. The utility must spread costs over a reduced number of kilowatt-hours, which results in higher rates, resulting in inequity among customers.

Although energy efficiency creates some similar cost shifts, there are several distinguishing characteristics between energy efficiency and DG: 1) The number of customers that invest in and accrue benefits from energy efficiency investments are greater and more widespread than customers currently investing in DG; 2) At current costs, energy efficiency investments result in lower costs from a total resource perspective, whereas DG still requires some subsidization; 3) Energy efficiency has smaller operational and planning impacts on the grid, such as the need for providing instantaneous power when a distributed generator fails.

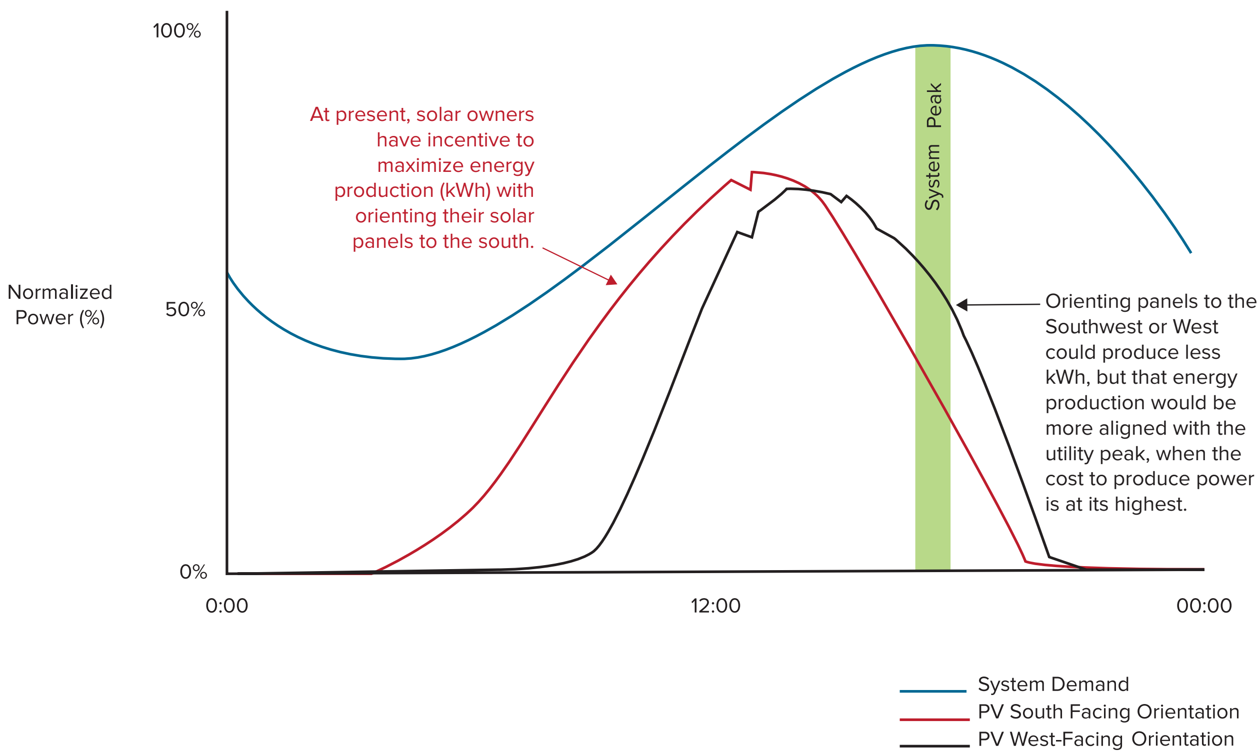
EQUITY

Where DG customers do not cover costs incurred for their grid service, these costs will be borne by other customers, resulting in inequity between NEM and non-NEM customers. Such rate increases, which are could be largely borne by upper-tier customers under existing rate structures, could lead to even higher rates of adoption, creating an unsustainable cycle.

MAXIMIZING VALUE BY ALIGNING WITH SYSTEM NEEDS

The degree of impact and value of DG and ZNE technologies to the grid depend on the correlation of their timing and magnitude to the needs of the system. However, currently DG or ZNE customers receive no signal to help shape their interactions with the grid to minimize costs or maximize value. For example, without a price signal to customers that indicates the value of energy throughout the day, net-metered solar customers' natural incentive would be to maximize the annual electricity output of their PV system. Thus, they would position their PV systems to maximize total energy output through a southern orientation. However, in a utility system that sees its peak loads in the midafternoon, as most do, a western-orientation solar system would provide power at the time in which energy is most valuable—at or

FIGURE 18
THE ORIENTATION OF SOLAR PV IMPACTS ITS CAPACITY AND ENERGY VALUE TO THE GRID



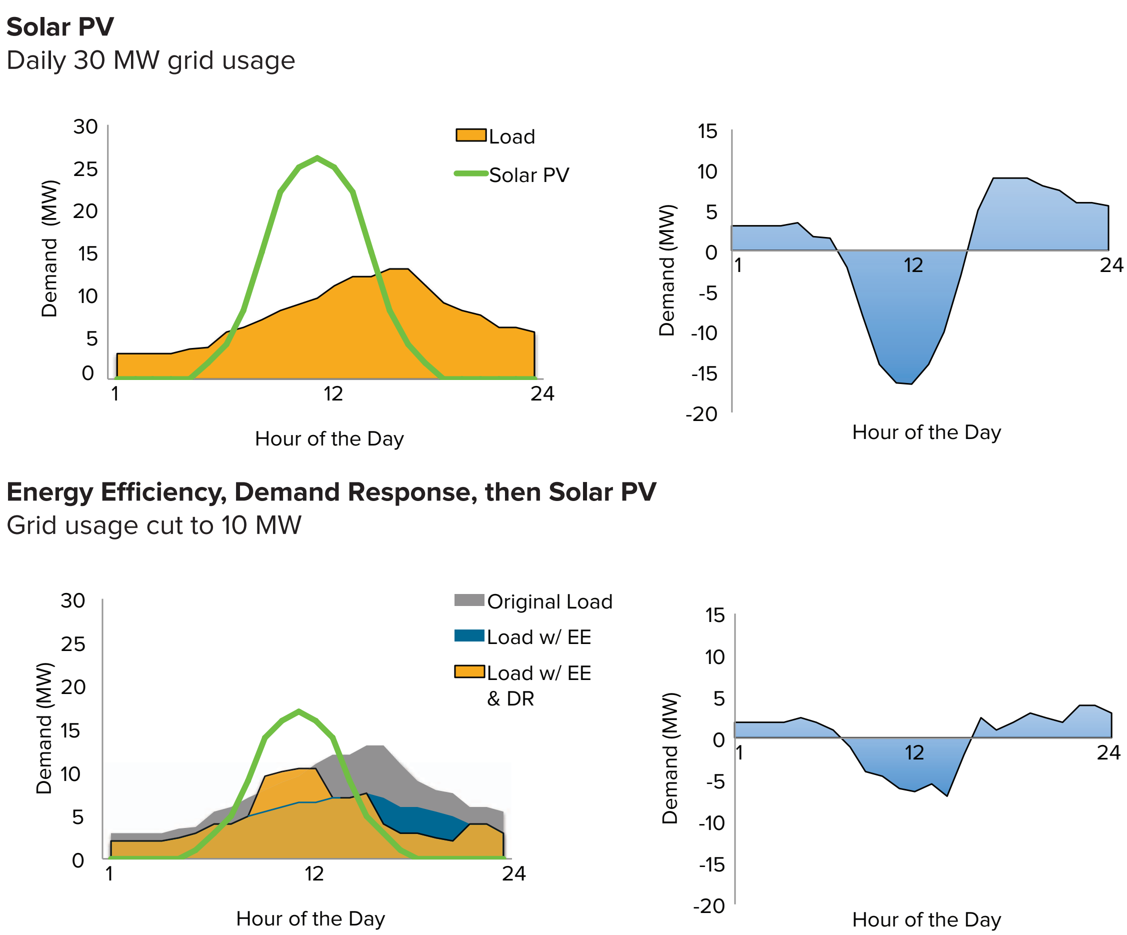
near the system peak (Figure 18). A time-differentiated price signal, such as time-of-use (TOU) pricing, could better match system needs by providing the incentive to increase peak contribution through customer solar production.

Further, from a planning perspective, the rise in DG popularity means an increasing flow of investment in generation capacity will occur outside of the control of the utility, either through capacity investments made on the demand side of the meter by customers or third parties on behalf of customers. Based on publically available renewable and thermal power plant power purchase agreement (PPA) contracts, the California Solar Initiative goals and Gov. Brown's targets for distributed renewables, one quarter of the cumulative investment in capacity out to 2020 could be made by the customer.[16] This could make system planning more challenging for the utility. Virtual power plants composed of distributed assets could begin to provide a significant contribution to the balancing needs.

ACHIEVING ZERO-NET ENERGY: TALE OF TWO BUILDINGS

A university campus that wishes to be "net zero" can accomplish this goal in a number of different ways—each with different value or impacts to the grid. One method would be to add as many solar panels as required to generate as much electricity as the campus consumes in a year. Another method could be to install a CHP system with thermal storage and microgrid controls to shift loads in response to price signals. Each of these methods would result in a net zero campus, but the solar solution would require the utility to provide more generation and T&D capacity as well as incur higher integration costs compared to the CHP/storage/microgrid solution (Figure 19). With volumetric prices, there is no incentive for the customer to adopt the solution that minimizes impacts on the electricity system and thereby minimizes the impact on utility rates for all customers.

FIGURE 19
ACCOMPLISHING "NET ZERO ENERGY" CAN HAVE VERY DIFFERENT GRID IMPLICATIONS



APPROACH TO SOLUTIONS

APPROACH TO SOLUTIONS

Tensions among different stakeholder views about the future implications of increased adoption of distributed solar in California are already beginning to play out in regulatory and political proceedings. There is a growing possibility that these differences in perspectives could result in prolonged and increasingly polarized conflict over policies, including utility rate design and net energy metering. Ultimately, however, it is important to find common ground among these different views in order to devise a sustainable electricity system that includes higher penetrations of distributed and renewable supplies while maintaining a healthy and reliable grid.

To move toward this goal, three basic issues must be addressed:

Identify, Measure And Communicate Impacts, Costs and Values

Remedy Misalignments Through Innovative Pricing Models

Adapt Utility Business Models To Create and Sustain Value

IDENTIFY, MEASURE AND COMMUNICATE IMPACTS, COSTS AND VALUES

Building a shared understanding among stakeholders and regulators in the electricity sector about the full range of costs and benefits of distributed energy resources and the implications of net energy metering is an essential first step toward devising rates and incentives that will create the greatest benefit for all. With limited experience of the integration of high penetrations of distributed energy resources, many questions remain to be answered about the net impacts. In addition, changes in technology, including new inverters and storage technologies, could have significant implications for costs and benefits in the future.

At present, although the lack of tools and analysis to fully address these questions remains a stumbling block, a growing number of studies are beginning to fill this void. Recently, four utilities have published analyses on the impacts of high penetrations of distributed PV systems within their service territories. The studies range in scope from impacts on the distribution system to regional balancing operations. The range of results is indicative of the case-specific nature of determining the impacts of distributed energy resources on utility operations and planning (Figure 20). Several ongoing utility studies of the impact of high penetrations of distributed energy resources on their networks will add to the existing body of knowledge over the next several years (Figure 21).

FIGURE 20

RECENTLY PUBLISHED STUDIES ON DISTRIBUTED GENERATION IMPACTS

Utility (Year Completed)		SACRAMENTO MUNICIPAL UTILITIES DISTRICT (2009)	ARIZONA PUBLIC SERVICE	SOUTHERN CALIFORNIA EDISON (2011)	NEVADA ENERGY (2011)
		Measured distribution impact from 238 kWac PV on 115-unit ZNE sub-division with eventual buildout of 1.2 MWac. The model will inform the acceptable level of penetration.	Evaluating the potential value of distributed solar resources to APS generation and T&D systems based on three penetration scenarios of PV adoption to 2025	Identifying PV system models and distribution system analysis tools to integrate high-penetration PV levels. Reviewing advanced inverter functionality.	Variable PV generation impact on system operations, balancing reserve requirements, and the ability of the existing generation fleet to accommodate increasing amounts of large-scale PV and DG in South NV.
		While it is possible to see the effects of PV on the voltage at homes and distribution transformers, PVs have not adversely affected voltage regulation and provide a large potential for peak demand savings.	APS' required upgrades and growth prevent any system deferrals until 2025. Upgraded transmission lines are inherently "lumpy" capacity additions. PV only obviates the need when it is widely adopted. High penetrations shift the peak later in the day.	Current distribution system modeling tools do not adequately model solar PV systems. New capabilities are needed. Advanced inverter functionality can clearly facilitate high penetration PV.	Spatial diversity mitigates some of PV's intermittency. For all penetrations of DG or PV of up to 15% of NCP load, additional balancing reserves are needed for regulation and load following. These costly operations run CCNG/CT less efficiently, require more unit starts, and ramp them faster.
COSTS OR BENEFITS					
GENERATION	CAPACITY	PV operation at 40 to 58% (S and W orientation, respectively) of rated output available during peak periods on SMUD's system	0–1.8 ¢/kWh for central gen deferrals	Unquantified	0–0.5 ¢/kWh (2011) for fast ramping, O&M.
GENERATION	ENERGY		7–8.2 ¢/kWh for fuel power, losses	Unquantified	0.3– 0.8 ¢/kWh (2011) for additional regulation units.
TRANSMISSION& DISTRIBUTION	CAPACITY	PV Penetration (at light loading of 4% of transformer, 13% of feeder) created no excessive service or substation voltage from reverse power flow. 40% penetration TX had 0.16% V rise.	0–0.8 ¢/kWh for T&D deferrals	Unquantified	Unquantified
TRANSMISSION& DISTRIBUTION	ENERGY		0.8–3 ¢/kWh for mainly Tran O&M savings	Unquantified	Unquantified
GRID SUPPORT		Not adversely affected voltage regulation. address peak demand.	Dependable PV capacity diminishes with Increased penetration as a result of pushing peak demand later.	Lower T&D loss and switching operations with advanced inverters. Ramping, frequency regulation, power balancing.	Large scale PV does not violate steady state voltage, transient voltage stability, or thermal loadings.

FIGURE 21

ONGOING STUDIES ON THE IMPACTS OF DG

Several utility projects and collaborative demonstration projects will add to the existing body of knowledge.

2010

HAWAIIAN ELECTRIC COMPANY (HECO)
APEC workshop on renewable energy grid integration systems (2009)

ARIZONA PUBLIC SERVICE (AZPS)
Distributed Renewable Energy Operating Impacts and Valuation Study (2009)

UNIVERSITY OF CALIFORNIA SAN DIEGO
Modeling tools (2010-12)

CLEAN POWER RESEARCH
Advanced modeling (2010-12)

SACREMENTO MUNICIPAL UTILITY DISTRICT (SMUD)
Anatolia (2010-2012)

NEVADA ENERGY
Large Scale PV Integration Study (2011)

ARIZONA PUBLIC SERVICE (AZPS)
Flagstaff (2009–2013)

SUNPOWER

2013

Resource forecasting (2010–2012)

NATIONAL RENEWABLE ENERGY LAB (NREL)/ SOUTHERN CALIFORNIA EDISON (SCE)
California (2010–2014)

PG&E/UNIVERSITY OF CALIFORNIA IRVINE
Integration limits (2011–2013)

COLORADO GOVERNOR'S ENERGY OFFICE
Solar PV and small hydro valuation

VIRGINIA POLYTECHNIC INSTITUTE & STATE UNIVERSITY
Power conditioners (2010–2014)

SAN DIEGO GAS & ELECTRIC / (SDG&E)
CALIFORNIA INDEPENDENT SYSTEM OPERATOR / (CAISO)
UNIVERSITY OF CALIFORNIA SAN DIEGO (UCSD)
System forecasting (2011–2013)

FLORIDA
Resource variability (2010–2015)

2015

UTILITY PILOTS
DEMONSTRATION PROJECTS

The challenge is that the degree of impact and value of distributed resources to the grid depend on the relationship among timing, magnitude, and location of distributed supplies and to the needs of the electricity system. Put another way, DG that is at the "right place at the right time" will create the greatest value. Additionally, the value of distributed resources is affected not only by timing and location, but also by the flexibility, predictability, and controllability of the resource.

For example, the capacity value of distributed energy resources, especially DG, is highly geographically specific and varies by distribution feeder, transmission line configuration, and composition of the generation fleet. Further, capacity investments, such as transmission upgrades or centralized generation plants, are "lumpy" in nature; therefore, it is necessary to determine the sufficient capacity demand reduction to avoid or defer transmission system investment. Thus, the capacity costs and benefits are highly variable and non-linear in nature, with the greatest value accruing in places of high system congestion and at times of peak demand.

DISTRIBUTED GENERATION: POTENTIAL SOURCES OF VALUE

Depending upon the type and amount of DG at individual nodes on the distribution system, strategic deployment could result in net benefits across the electricity value chain, including generation, transmission, and distribution, as well as across varying time scales, from real-time operations to long-term planning (Figure 22). The potential benefits of DG result from the installations' inherent characteristics: they are smaller in unit size, can be constructed in shorter lead times, and can be installed closer to demand. From an operational perspective, the potential value to the utility network from DG depends on attributes including variability, predictability, and contribution to peak supply.

Displacing Conventional Generation By displacing the need to produce energy from conventional sources, DG could decrease fuel and purchased power requirements. Additionally, onsite thermal generators like mini-CHP plants or fuel cells can also often reuse waste heat nearby, displacing fuel and equipment.

Reducing Line Losses Line losses average between 6-7% but can double when demand is high and lines are strained. Generation produced at or close to demand can obviate these losses.

Reducing Transmission Investment By pinpointing congested, high-cost areas, DG could be deployed reduce the use of strained transmission or distribution capacity, thereby reducing or deferring the need for additional capacity investments.

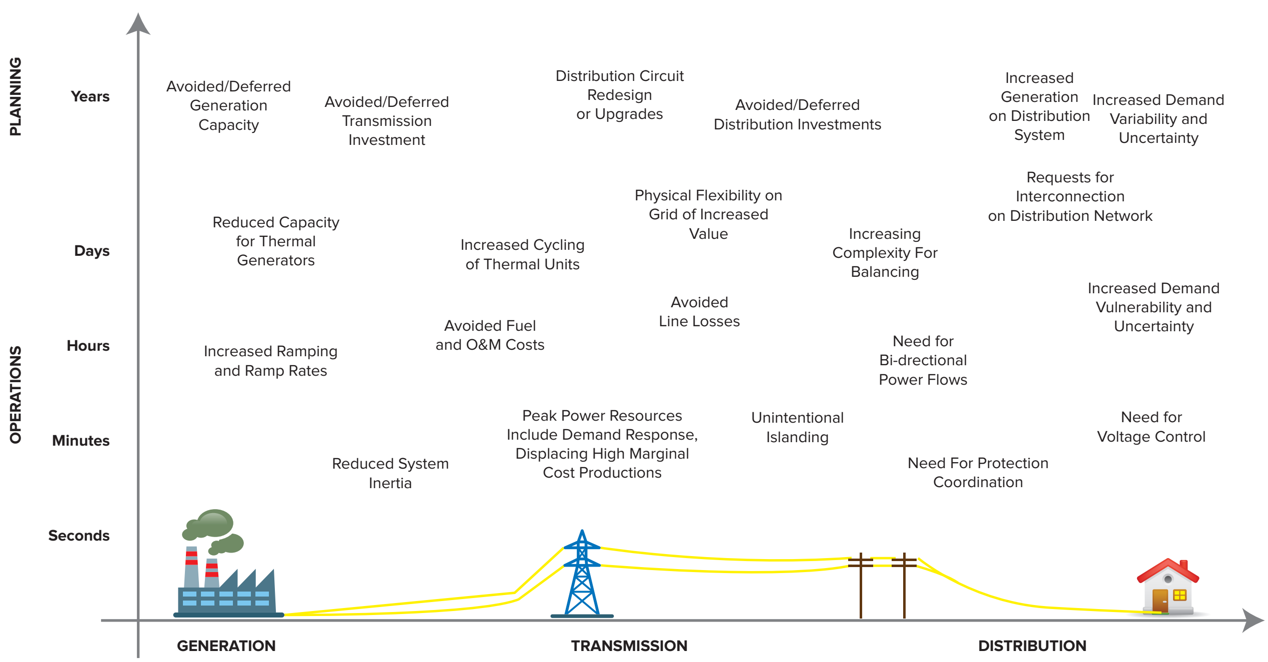
Reducing Financial Risk Associated With Larger Scale Investments Distributed resources' combination of short lead time and small unit size lets utilities reduce financial risk by building capacity in increments more closely matched to changing customer demand.

Deferring or Reducing Grid Investment By pinpointing congested, high-cost areas, DG could be deployed to reduce the use of constrained transmission or distribution capacity, thereby reducing or deferring the need for additional capacity investments.

FIGURE 22

HIGH PENETRATION OF DG COULD HAVE POSITIVE OR NEGATIVE IMPACTS ACROSS THE ELECTRICITY VALUE CHAIN

At the system level, large scale adoption of DG results in impacts that could translate into new costs or new sources of value and for different actors.



More research is needed to quantify these impacts in order to create pricing or incentive structures that properly account for the costs or benefits of these resources. Such analysis will require evaluation of impacts of distribution system capital and operating costs, balancing costs, fuel use and a wide range of other considerations. New data collection and analysis methods will be necessary to develop estimates of these costs and benefits while ensuring accountability, transparency, and verifiability of cost and benefit estimates that will provide the foundation for policymaking.

REMEDY MISALIGNMENTS THROUGH SUSTAINABLE PRICING MODELS

Electricity rate structures that bundle the utility's many disparate costs into a single volumetric rate provide customers with simple electricity bills together with strong incentives for energy efficiency and distributed generation. With significant penetration of customer-level generation and net metering, however, this pricing model begins to break down. Under current volumetric rate structures, net metering does not accurately recover the costs of a customer's use of the grid network and, simultaneously, it may not be compensating the customer for the value of the power they are providing.

PERSPECTIVES

CAN ROOFTOP SOLAR PV GENERATE SIGNIFICANT COST SAVINGS IN THE ELECTRIC UTILITY DISTRIBUTION SYSTEM?

YES. Adding solar generation capacity can reduce distribution systems costs in a variety of ways. Increased distributed supply can prolong lifetimes of transformers and other equipment on the utility system by regularly reducing loads during peak periods. Where solar PV supply is reliably correlated with peak demand, distributed supply may allow utilities to avoid or defer capacity expansion in parts of the distribution system. The experience of regional transmission organizations (RTOs) such as PJM indicates that distributed resources have provided a large share of the resources procured through capacity auctions. In the long run, if there are appropriate incentives, distributed solar, coupled with electricity storage and necessary communications and control equipment, may be able to provide increased capacity value to the electricity grid. Eventually, with advanced inverters, solar systems may even help to provide voltage regulation and reactive power on distribution system feeders.

NO. All the assets on the distribution system are needed to serve energy deliveries and energy exports for electricity customers. Utility rooftop PV provides little or no offset to the amount of distribution capacity that the utility must provide, since the utility must stand ready to provide electricity supply to customers when solar power is not available. Solar power supplies may not correlate well with system peak electricity demand, so capacity requirements on the utility system may not be reduced even under the best of circumstances. In some cases, high penetrations of distributed solar power may necessitate making additional investments in the distribution system to handle the power exported by solar systems at periods of peak supply.

The generation of onsite power is not in itself flawed; rather, the problem is rooted in the underlying rate structure. Moreover, the combination of traditional rates and net energy metering incentives do not provide price signals that incent the customer to provide the greatest possible value to the electricity system. As a result, investment in new DG capacity may be made without regard to how the timing and location of those resources will influence power system operation. Existing rates and policies obscure the costs and benefits of distributed resources to the grid, limit the ability to add smarter integration technologies, which could add value, and restrict signals to the customer that would enable them to make mutually beneficial decisions. These misalignments may be negligible at low penetrations of DG, but as the share of distributed generation increases they become significant.

Legislative and ratemaking changes may be necessary to create a sustainable long-term path for distributed resource development. Utilities and their regulators are considering new and modified rate structures that provide the price signals necessary to promote and realize the full value of not only DG, but also EVs and the Smart Grid. Rate design should ensure two things: that utilities receive adequate compensation to cover their prudent costs, and that those costs are distributed among customers equitably, so a customer's electricity bill is representative of the value of the services provided to, and by, that customer.

In developing new rate structures, utilities will be forced to reexamine the fundamental elements of the "cost to serve"—capacity related fixed costs, non-capacity-related fixed costs and variable costs[17] —and the allocation of these costs as they pertain to customer-generators. For example, distributed generators produce power that directly displaces generation from

PERSPECTIVES

SHOULD CALIFORNIA'S UTILITY RATES SHIFT TOWARD GREATER FIXED CHARGES?

YES. The lack of cost recovery from fixed charges in residential rates, for example, customer charges or demand charges, has caused the upper tier rates to be higher than they otherwise might be. Industrial customers, for example, pay demand charges. The current exemption for solar customers from standby charges and generation-related stranded costs has hampered the ability of utilities to recover the appropriate level of costs when customers choose to install solar systems. As a result, customers with solar PV are being subsidized by other customers who pay higher rates to cover the costs of service to these customers. In the long run, this could result in a vicious cycle of rate increases on upper tier customers leading to further solar PV adoption—a "death spiral" scenario for the electric utility.

NO. Rate designs with minimal fixed charges create the strongest incentives for energy efficiency and solar investments, and are therefore aligned with social and policy objectives. Increased fixed charges would reduce incentives for efficiency and solar and reduce incentives for utilities to aggressively manage costs.

centralized power plants. One issue is the true value of this power—and, therefore, the rate at which it should be credited—since generation costs are only a portion of the full cost of electricity service and vary. In addition, a straightforward assessment of the value of power from DG is complicated by the temporal and locational variability in the costs and benefits of individual systems. Distribution feeders with large amounts of DG capacity downstream may require upgrades to maintain power quality, or, conversely, if implemented carefully and thoughtfully, may alleviate congestion and potentially defer the need for upgrades.

To equitably distribute costs, a utility cannot simply levy energy, demand, and customer charges equally across all customers. This would require individual customers to be charged for the cost to provide them with service, and also compensated for any value that they create. In reality, however, cost causation principles are not the only factor that utilities must take into account during the ratemaking process. Technological constraints limit the level of specificity that rates may have and determine the degree to which time and location may be valued, while the potential consequences in terms of load shifting and load growth (or reduction) must also be considered. At the same time, for any rate structure to gain PUC approval it must strike a balance between the interests of traditional customers and customer-generators, while remaining simple enough to be understood by customers. The utility must ask: can the pricing model pay for operational services, properly capture and promote value

PERSPECTIVES

SHOULD CALIFORNIA IMPLEMENT A REVISED APPROACH TO NET METERING, ESSENTIALLY "NET METERING 2.0?"

YES. Revising net metering rules and utility rates will reduce the conflicts created by the cross-subsidy implicit in the current rate system which requires that customers without solar systems pay part of the cost of utility services to those customers with solar. Revised net metering rules could level the playing field to reduce or eliminate these cross-subsidies and provide a stable revenue model for the utility for the future in the event of high levels of solar adoption. Net metering 2.0 might unbundle charges so that the utilities could recover revenues for customers' use of the distribution system wires to export power to the grid and provide more refined incentives for customers to install systems and manage their energy use to create the greatest benefit for the electricity system.

No. Revising net metering rules today would slow the adoption of rooftop solar PV, resulting in the loss of jobs in the solar industry. Net metering socializes the costs and benefits of distributed solar, which is reasonable in view of the societal benefits of distributed solar power.

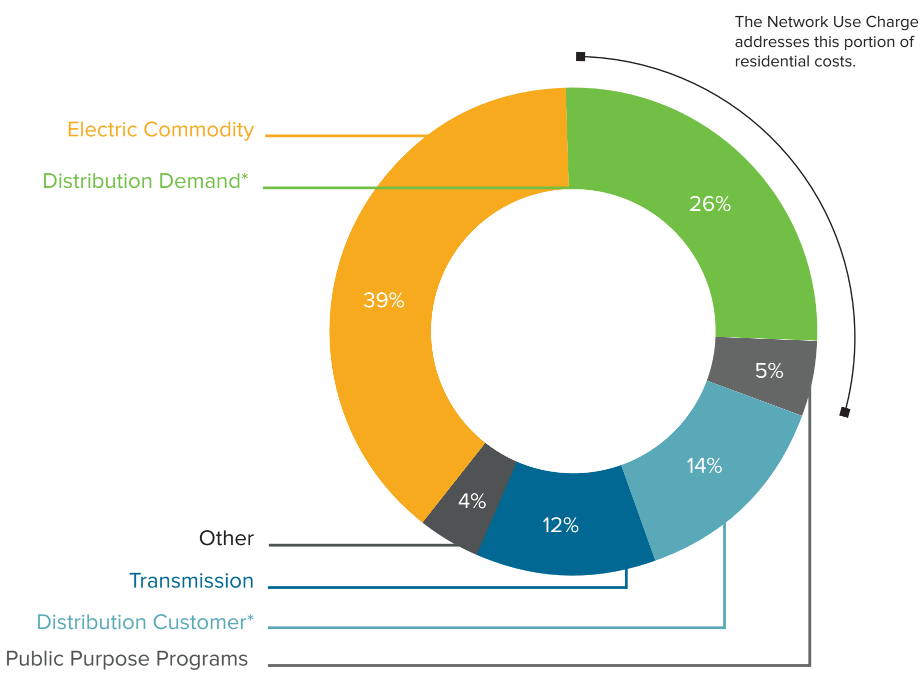
to the system, and be implemented effectively with the flexibility to accommodate a changing system? On their own, many pricing models pay for different services or capture sources of system value, but few meet all of these criteria. However, smart combinations or hybrids of pricing models may ultimately create a nimble system that pays for required services, maximizes value, and allows for effective implementation.

San Diego Gas and Electric Company (SDG&E) provides an example of a utility attempting to modify its rates as it prepares for higher penetrations of DG. As part of its General Rate Case in October 2011, SDG&E proposed modifying its residential electric rates to include a "Network Use Charge," which would bill customers for the costs associated with network use.[18] Figure 23 shows the portion of the costs to serve a residential customer encompassed by the Network Use Charge. Currently, customers utilizing NEM avoid paying for these fixed

FIGURE 23

COST ALLOCATION FOR RESIDENTIAL CUSTOMERS

SDG&E's Network Use Charge addresses the demand-related fixed costs that are currently contained within standard volumetric rates.



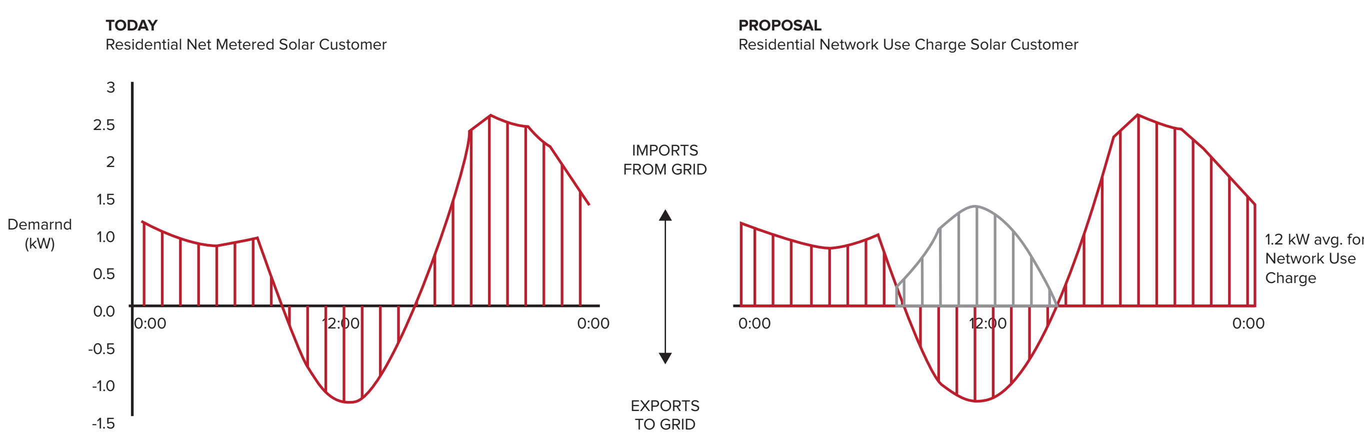
* SDG&E cost studies identify two cost components to the distribution system for providing service to customers: customer costs and distribution demand-related costs.

costs. SDG&E proposed to measure a customer's absolute demand as a basis for the charge, which would account for the fact that when a customer-generator has negative demand—therefore exporting power—the customer is still in fact using the utility's network (NEM vs. NUC). Proponents of the Network Use Charge note that it would allow SDG&E to ensure that NEM customers pay for their fair share of distribution system costs when exporting power, while reducing the inequitable cost shifts that result from retail NEM. However, the measure met with fierce opposition from the solar industry, consumer advocates, environmentalists, and NEM customers. These groups argue that the Network Use Charge does not account for the benefits that DG systems provide to the network, that it runs contrary to California's renewable energy goals by discouraging solar, and that it does not send price signals that encourage reduction in coincident peak demand—rather, it pushes PV owners to shift their demand to times when their system is producing, i.e. midday.

SDG&E's Network Use Charge illustrates the difficulty of the challenge, and of how sensitive the many stakeholders are to the implications of any proposed change to existing rates. An acceptable solution will be needed to balance the needs of the network with the concerns of its stakeholders, which will likely require compromise from both sides. This process will ultimately create new profit opportunities that, given the right price signals, will allow distributed generators to adapt and provide new sources of value to the utility system.

FIGURE 24
SDG&E'S PROPOSED NETWORK USE CHARGE

The Network Use Charge would measure the absolute value of a customer's demand, accounting for network use by NEM customers when exporting power.



ADAPT UTILITY BUSINESS MODELS TO CREATE AND SUSTAIN VALUE

While the steps described in previous sections of this report are necessary to address misalignments in existing institutional and pricing structures, they are not sufficient to provide a long-term, sustainable foundation for the electricity system. The key drivers that are transforming the electricity industry—slow or declining demand, increased variable renewable generation, increased customer generation and energy management, and environmental priorities—will continue to alter revenue streams, sources of value, and operational requirements for electric utilities. This, in turn, will necessitate further evolution and adaptation of utility business models.

Important steps have already been taken in California to shift the utility business models toward new approaches that align utilities' profit motives with social priorities and emerging market realities. For example, revenue decoupling breaks the link between electricity sales and utility profits. However, basic elements of the utility business model still must be addressed. The key question, as framed by roundtable participants, is: What are the functions that utilities will perform in the future and how should we create mechanisms to appropriately compensate utility companies for performing those functions?

Utility business models are largely shaped, but not completely determined, by the regulatory policies. With the rapid growth of distributed resources that provide increasing alternatives for customers, new questions are emerging about the role of the utility and other actors. Should the utility be allowed to own and operate distributed resources on its customer's premises? What incentives should the utility have to ensure that distributed resources are fully deployed to minimize costs for the system as a whole? If the utility is allowed a more expansive role in owning and/or managing distributed energy assets, will this unfairly crowd out other competitors?

Roundtable participants discussed the relative merits of two approaches to regulating electric utilities' roles and activities in these areas:

> New forms of incentive regulation to support a more expansive role for utilities in managing distributed resources
>
> A more limited network utility model that relies on highly differentiated price signals to direct investments in distributed resources by customers or other intermediaries for greatest system benefit.

While these approaches suggest different emphasis in how to overcome the limitations inherent in existing policies are not mutually exclusive, so solutions could be constructed with elements from each.

New approaches to incentive regulation could provide utilities with stronger motivation to direct and manage investments in distributed energy resources. Performance incentives include performance based earnings, shared savings, and incentive rates-of-return. These mechanisms could be used to reward utilities for performance in achieving distributed resource deployment targets, and in doing so in a way that minimizes costs for the system as a whole. In the same way that revenue decoupling and shared savings policies together can provide strong incentives for utilities to invest in energy efficiency, a similar approach could strengthen incentives for utilities to invest in distributed generation, storage, microgrids, smart electric vehicle charging, smart inverters, or other distributed technologies to reduce operating costs and/or defer or avoid the need for investments to expand capacity of distribution feeders or invest in other electricity supply, transmission, or distribution assets. Under some scenarios, the utility might be allowed to invest in and earn a return on assets on the customer side of the meter that offer the least-cost means of delivering service.

Proponents of this approach argue that utilities are in the best position to understand how and where to deploy distributed resources for greatest system benefits and should be allowed greater freedom to direct these investments to the areas on their system where they provide the greatest value. Moreover, performance incentives should ensure that utilities earn more by finding the least-cost ways to address system needs. If it costs less to deploy distributed resources in a targeted fashion than it would to make rate-based investments to reinforce or upgrade the grid, then utilities should be made better off by implementing the solutions that costs customers the least.

The portfolio of distributed resources available to the utility might include a wide range of assets and technologies, from distributed generation and storage to microgrids that enable control and dispatch of local resources in response to price signals from the grid. Under this model, the utility would fill the role of both network orchestrator and service provider. The utility would continue to perform many of the key functions of a historically vertically integrated utility, such as ensuring reliable power delivery, as well as owning and operating some generation resources. It could offer a variety of emerging new services that are enabled with the technological advances in distributed generation, grid intelligence and communications. The utility would have incentives to deploy distributed resources wherever doing so could reduce the cost of providing electricity services. This approach would require significant changes in the current regulatory paradigm to ensure a level playing field for service providers, including energy service companies and other onsite generation providers. A key challenge is that alternatives to the conventional return-on-rate base, such as performance-based regulation, have proven complex and difficult to execute.

Incentive regulation can take relatively simple forms. For example, legislation introduced in the U.S. Senate by Senators Amy Klobuchar (D-MN) and Tim Johnson (D-SD) in the summer of 2011 proposed a "Renewable Integration" tax credit to offset the costs of integrating wind and solar resources to the grid. The tax credit would provide an incentive for utilities to adopt more renewable power by offering a tax credit of up to 0.6 cents per kWh for power supplied from variable renewable sources such as wind and solar. If utilities can integrate supplies from these sources at costs less than the level of the tax credit, they can profit accordingly.

Under a network utility approach, the utility would provide highly differentiated price signals to direct investments by other service providers. In this case, the utility's role would increasingly be focused on maintaining and operating the grid and on creating markets, managing transactions, replacing aging distribution equipment, and/or making smart grid investments and interconnecting buyers and sellers with the network. This network utility would shepherd and coordinate the network of increasingly complex transactions among growing number of actors. The utility in this scenario would evolve toward a role more like that of grid owner/operators at the wholesale level, enabling markets for energy, capacity, reserves, and ancillary services that differentiate value for these services according to time and location.

New product revenue streams to achieve profitability would include investments that improve network operations and facilitate market. Key challenges in this paradigm are determining how a network utility should be compensated as the enabler of the network and in setting benchmarks for performance.

PERSPECTIVES

WHAT IS THE BEST APPROACH FOR ADAPTING UTILITIES TO 21ST CENTURY ELECTRICITY INNOVATION?

NEW FORMS OF INCENTIVE REGULATION could allow the utility to innovate and meet customer's changing needs while expanding its range of offerings to ensure the vitality of a functioning electricity system. Under this approach, the utility would have incentives to invest in owning and operating distributed resources on customers' premises, or to contract for other entities to do so, where such investments could reduce the overall costs of providing electricity services. The costs and benefits of distributed resource development would be fully socialized, and the utility would have strong incentives to achieve all available cost savings from distributed resource deployment. The utility might be required to outsource distributed resource deployment to other companies, but would ultimately manage where and how such resources would be deployed. The utility has the responsibility for maintaining reliability and serving all electricity customers fairly. Under an incentive regulation approach to distributed resource development, customers that cannot invest in distributed resources or take advantage of solar lease offers would not be disadvantaged. These customers might, for example, participate in utility programs that oversee the installation of solar panels at optimal places within the utility system on behalf of such customers, providing benefits similar to those available from rooftop systems.

THE NETWORK UTILITY MODEL is the right approach because it allows the competitive markets to direct the provision of innovative technologies and services to customers, while providing incentives that reflect the costs and benefits to the grid from distributed resources. The utility isn't the most efficient or cost effective provider to install distributed resources on the customer's side of the meter, or even to manage such investments through contracting to third parties in today's rapidly changing environment. The utility of the future will look increasingly like today's independent system operators: providing time-varying price signals via the grid that encourage other companies to make customer-level investments to create value by providing energy supply, managing load shapes, or providing ancillary services to help manage the grid.

LOOKING AHEAD: FUTURE CHALLENGES AND OPPORTUNITIES

The rapid growth of solar PV adoption by electricity customers in California foreshadows far-reaching changes in the state's electricity system in the decades ahead. As costs of solar PV systems continue to fall, it is clear that this technology can play a significant role in helping to build a bridge to a low-carbon energy future. At the same time, important questions are arising about how best to design electricity rates and policies to ensure that solar power and other distributed resources are developed in a way that provides greatest benefits to electricity customers and to society as a whole. Policies created to stimulate the growth of the solar industry in its early stages will need to be modified as the industry matures, new technologies emerge, and impacts on the utility system increase. Ideally, these policies will provide incentives for deployment of solar power in ways that create the greatest value for the system as a whole, while simultaneously benefitting the customers that adopt solar.

Beginning the conversation about changing existing incentives for solar power has risks. The escalation of rhetoric expressing opposing views can lead to polarization and impasse. Uncertainty about changes in policies can deter customers from making decisions to adopt solar, with damaging consequences for the solar industry. On the other hand, new policies must be developed that provide a sustainable long-term foundation for solar development and a sustainable foundation for a healthy electricity grid. While participants in the RMI-PG&E roundtable did not reach consensus about specific policy measures or utility business model innovations, they did agree about the need for change and the initial critical steps, that could lay the foundation for sustainable long-term solutions:

1. **IDENTIFY AND MEASURE IMPACTS, COSTS AND VALUES OF DISTRIBUTED ENERGY RESOURCES**

2. **REMEDY MISALIGNMENTS BETWEEN ECONOMIC INCENTIVES TO CUSTOMERS AND THE COST AND VALUE TO THE SYSTEM PROVIDED BY DISTRIBUTED RESOURCES**

3. **ADAPT UTILITY BUSINESS MODELS TO CREATE AND SUSTAIN VALUE IN A FUTURE CHARACTERIZED BY HIGHER LEVELS OF EFFICIENCY AND INCREASED DEPLOYMENT OF DISTRIBUTED RESOURCES**

ENDNOTES

1 E3's study estimated that, for customers who installed systems in 2008, the levelized cost shifted to other customers as a result of the California Solar Initiative was $0.26/kWh generated based on the Ratepayer Impact Measure (RIM) test. The study estimated that this cost shift declined to $0.21/kWh generated in 2009 and would decline further to $0.10/kWh generated by 2017. ("California Solar Initiative Cost-Effectiveness Evaluation", Energy and Environmental Economics, April 2011, Table 52, Table 56, and Table 60 p. A-26-A-30.) The extent to which CSI and Net Energy Metering (NEM) policies impose costs on non-NEM customers is controversial, and E3's conclusions about NEM have been disputed by other analysts. While analysts disagree about the level of "cost shift" that results from CSI and NEM policies based on differences in analysis approaches and assumptions, there is broad agreement that the results are heavily influenced by rate design. As rates structures change, so will the cost-effectiveness of CSI and NEM. With respect to NEM, E3 concluded that, under 2008 rates, the average net cost of NEM to non-participants for generation installed through the end of 2008 was $0.12/kWh exported. ("Net Energy Metering Cost-Effectiveness Evaluation", Energy and Environmental Economics, January 2010, Table 3, p.7.) A subsequent study by Lawrence Berkeley National Laboratory estimated that the net cost of residential NEM was $0.02-0.05/kWh exported. (Dargouth, N., Barbose, G., and Wiser, R., The Impact of Rate Design and Net Energy Metering on the Bill Savings from Distributed PV for Residential Customers in California, April 2010, LBNL-3276e.) Finally, a study published by Crossborder Energy in January 2012 estimated that the net cost of NEM was $0.02/kWh exported. (Beach, R., McGuire, P., "Re-evaluating the Cost-Effectiveness of Net Energy Metering in California, Crossborder Energy, January 17, 2012.)

2 "California Solar Initiative Cost-Effectiveness Evaluation", Energy+Environmental Economics, April 2011

3 California IOUs cost recovery is separate from rates, with an annual adjustment to account for differences between forecasted sales and actual sales. This means utilities will recover authorized fixed costs without over- or under-recovery as a result of fluctuations in weather or customer energy efficiency.

4 PG&E residential rates currently have four tiers with prices that increase as usage increases.

5 D.Moskovitz, Profits and Progress Through Distributed Resources, published by the Regulatory Assistance Project (www.rapmaine.org), Maine, USA, February 2000

6 Again, many stakeholders consider distributed generation to be any generation connected at the distribution level, whether serving customer load, or merchant generation.

7 While net energy metering has been commonly implemented across the U.S. to value exported power from customers at full retail rates, the concept of net energy metering does not equate to compensation at retail rates.

8 As with similar policies, FITs will not necessarily result in beneficial siting of DG unless location and other attributes are taken into account in the tariff design.

9 FERC recently updated the rules governing FITs, which will likely stimulate additional use of FITs in the U.S

10 Lawrence Berkeley National Lab, Tracking the Sun IV

11 CA IOUs have deployed 8.8 M of 11.95 M electric SmartMeters, while nationally 65 million SmartMeters will be deployed by 2015.

12 At the outset of the CSI program in 2007, the initial $2.50 per watt

incentive offset 25% of the system cost.

13 Levelized cost of energy (LCOE) is defined as the total cost of building and operating a generating plant over its life.

14 LCOEs calculated from http://www.pvcostconvergence.org/calculator.aspx, assuming a 4kW residential system in the year 2012 located in San Jose, with Federal ITC and CSI incentives, aggressive PV cost declines, and a financing structure of either 0% down 4% interest or 30% down 6% interest.

16 "Utility" investment is considered to be any generation built or directly contracted for (through a PPA) by the utility while "customer" refers to any generation investment on the customer side of the meter, whether owned by the customer or a third party. This forecast is based on publically available supply plans for thermal generation and large scale renewables to meet the 33% RPS for the utility, and distributed generation policy goals for the customer. The value of investment is based on forecasts of technology costs from the EIA and national labs.

17 As detailed on p. 42, a utility's cost to serve are broken into three main categories: non-capacity-related fixed costs are overhead expenditures incurred as a direct result of a customer's existence, capacity-related fixed costs stem from the T&D and generator capacity required to serve the customer, and variable costs covering the fuel, operations, and maintenance costs associated with generating power.

18 On January 18, 2012 CPUC found that this proposal was out of scope for the instant proceeding.

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About Rocky Mountain Institute

Rocky Mountain Institute (RMI) is an independent, entrepreneurial, nonprofit think-and-do tank. RMI emphasizes integrative design, advanced technologies, and mindful markets in fulfilling its mission to drive the efficient and restorative use of resources. RMI's strategic focus is to map and drive the U.S. transition from fossil fuels to efficiency and renewables by 2050.

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