AN ENERGY POLICY ESSAY

Renewable and Distributed Power in California

Simplifying the Regulatory Maze—Making the Path for the Future

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Introduction

California and many other U.S. states will see more changes in their electricity systems over the next 15 years than they have in the past half-century. California has embarked upon an unprecedented effort to change, rapidly and fundamentally, the state's electricity supply and delivery system. Utility-scale, fossil-fired power plants are being phased down. A new system driven by renewable and distributed power of all sizes and technologies, owned by customers, utilities, and third parties alike, is being put in place. An overlay of demand-side resources and new information technology is likewise expanding. These ambitions have been crystallized through the state's climate change law (AB 32)[1] and net zero energy goals,[2] the law mandating the use of renewable power for 33% of California's electricity supply by 2020,[3] and by Governor Brown's goals to develop 12,000 MW of distributed generation by 2020 and 6,500 MW of combined heat and power (CHP) by 2030.[4]

While much commentary has focused on the technological aspects of renewable and distributed power development, little attention has been paid to a fundamental question—are the traditional electric system regulator and utility institutional structures sufficient to support this massive transformation?—and, if not, what changes are needed? This paper seeks to answer that question. It focuses on California because its renewable and distributed energy efforts are among the most far-reaching in the United States. But the implications are applicable to the success of ambitious renewable and distributed power development goals throughout the United States.

Stress in the institutional structure of California's electricity system can already be observed. California has 11 programs for renewable power development, with differing goals, timelines, and criteria. Electric utilities are forecasting increased costs and rates after decades of relative stability. Equitable allocation of these costs across consumers with different and novel electricity service needs will likely require major changes in past practices.

One underlying structural cause is the California electricity system's regulatory and institutional framework, which is tasked with implementing the state's clean energy goals. Three major state agencies, with the addition of an independent transmission system operator, the Governor's office, and the Legislature, are all involved. While the leadership and staff have significantly increased cooperative efforts, there are serious gaps and overlaps in regulatory oversight. No single state entity is in charge of integrating initiatives and addressing gaps, decision making is slow and siloed, and—most importantly—there is no consolidated roadmap and decision-making schedule.

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Another fundamental problem is the increasingly outmoded business model of utilities. As California seeks to transform its electricity system, investor-owned utilities face a regulatory system that penalizes innovation and risk-taking, a potentially diminished service base, and an unfamiliar, competitive energy-service landscape. New, non-utility entrants to the electricity sector provide a variety of services, sometimes in competition with utilities, but no sustainable roadmap has been developed for their role. The lack of utility incentives and a viable, competitive services framework is slowing private investment and stalling technology adoption.

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California's situation illustrates the problem of trying to transform the physical electricity grid while only marginally adjusting the regulatory and governance environment that surrounds it. California's experience suggests that an ambitious scale-up of utility-scale renewables and distributed power systems requires an equally ambitious structural reform in the existing regulatory framework and the traditional regulated utility business model.

Is there a path forward to ensure that the institutional framework—for regulators, utilities, customers, and new entrants alike—can not only withstand but also rapidly evolve to support the equally rapid evolution of an electricity system leaning towards renewables, distributed generation, and increasingly sophisticated customers? The answer is "yes."

Improvements can be made, without designing a new institutional structure from scratch. While the treating of some of the current symptoms will be relatively straightforward, addressing their root causes will require significant additional changes. Without such reforms, California's ability to achieve its clean energy transformation goals while not jeopardizing its reliable and affordable electricity system is at risk.

Our recommendations to address these institutional issues include the following:

Short Term:

- Identify a lead agency and develop a consolidated program document, implementation roadmap (a starting point could be the California Energy Commission's recently released draft, "Renewable Action Plan"), and agency decision-making schedule for California's renewable and distributed resources goals, with public meetings to report progress.

- Publicly release program costs and actively identify potential systemic economic and operational risks.

- Address the problems inherent in cost-shifting to a narrow base of customers and identify rate options that encourage long-term public support for distributed power.

Longer Term:

- Establish clear agency responsibility for renewables and distributed energy programs, and adopt consistent decision-making criteria across planning, procurement programs, and agencies.

- Reform agency decision making to cross agency, planning, and program siloes to identify and resolve development risks and to rapidly expedite timelines.

- Develop an investment plan for California that identifies the full range of possible costs and pathways to maximize private investment and lower costs.

- Adopt new business models for utilities that provide incentives to drive the desired transformation in an efficient and innovative way, and revise the way utilities are regulated to support decentralization of California's electric system and investment in new technologies.

- Create sustainable pathways for non-utility entities to provide energy services.

BOX 1: California's Electricity System: Providers and Regulators

In 2011, California generated about 70% of its electricity in state, with the remainder imported from California's western neighbors. Natural gas provides the main source for electricity generation. About 17% of the in-state generation in 2011 was from renewable resources—biomass, geothermal, small hydro, wind, and solar generation. California has a mix of investor-owned utilities (IOUs), publicly owned utilities (POUs), and other entities that deliver electricity.[5]

The three major electric IOUs are Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). While historically California IOUs sold to their retail customers electricity generated from power plants that they themselves owned and operated, today most electricity sold by the IOUs is first bought on the wholesale power market from independent power producers (IPPs), both in- and out-of-state. The IOUs then re-sell that power to consumers in monopoly service areas through low-voltage distribution grids that they own and maintain. Numerous POUs are owned and operated by public entities, generally their local municipalities. Major California IOUs, POUs, and their shares of California's electricity sales are listed below:

TABLE 1: California's Top Load-Serving Entities[6]

Utility	Type	Share of CA sales (2010)
Pacific Gas and Electric, PG&E	IOU	30.7%
Southern California Edison, SCE	IOU	29.9%
Los Angeles Dept of Water and Power, LADWP	POU	8.3%
San Diego Gas and Electric, SDG&E	IOU	7.1%
Sacramento Municipal Utility District, SMUD	POU	3.7%
CA Dept of Water Resources, DWR	Public LSE	2.8%
Burbank, Glendale, and Pasedena Municipal Utilities	POU	1.2%
Imperial Irrigation District, IID	POU	1.2%
Silicon Valley Power, SVP	POU	1.1%

Electric Service Providers (ESPs) and Community Choice Aggregators (CCAs) also supply electricity in California. ESPs are non-utility entities that offer electric service directly to retail customers within the service territory of an electric utility, pursuant to California's earlier attempts at electric deregulation. CCAs are a newer form of provider, established by cities and counties to provide electric generation to their residents, businesses, and municipal facilities in community-wide electricity buyers' programs.[7] Both ESPs and CCAs rely upon the distribution network of the local IOU.

There are a multitude of other key entities in California's electricity system. One important group is the merchant generators / independent power producers (IPPs), who own power plants and sell power on the wholesale market to the utilities. Another group is demand aggregators, who contract with retail customers to reduce demand in times of peak electricity needs.

Four state-level entities are responsible for major aspects of California's electricity structure: the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), the California Air Resources Board (CARB), and the California Independent System Operator (CAISO). Both California Governors and the California Legislature historically have been very active in driving California energy policy and specific programs. A host of other governmental units, such as the California Water Resources Board, local governments and permitting agencies, federal agencies, and locally owned utilities, also affect key aspects of electricity, particularly renewable and distributed power development.

CURRENT STRESSES

Changing paradigms does not come easily. California's drive to shift towards a clean energy, renewable-focused generation system has, not surprisingly, introduced substantial pressures throughout the system. These tensions are now beginning to impact not just isolated consumers but also the utility business model and system transformation goals more broadly. The key stresses we address in this section are the following:

- First, a complex maze of layered and changing policies, programs, and rules has built up over time; the barriers to understanding or entering new markets are high and overall clarity is low;

- Second, an unprecedented number of new capital investments, which are needed for the generation, transmission, and distribution of power to replace aging infrastructure, meet renewable and environmental goals, and ensure reliability, are collectively contributing to rising utility costs and consumer rates;

- Third, the costs and benefits of renewable and distributed power differ from those of conventional power, affecting some electric users and usage types differently than others; regulated rate structures have not been modernized to match this new paradigm, and existing cost allocation has resulted in significant, new inter-consumer cross-subsidies.

This section reviews each of these three stresses that are observable today in California. Other states undergoing electricity system transformations with similar structural shortcomings may see similar phenomena. And though regulatory agencies may attempt to manage these problems as they arise with existing tools, their responses will ultimately be reactive in nature without deeper institutional reforms.

The Policy Maze: California's Renewable and Distributed Power Programs

California has the most ambitious—and complicated—renewable program in the United States. An incremental agglomeration of policy goals and priorities by various regulatory stakeholders over the years has left the state with a dense web of renewable and distributed power-related programs. Below is an overview, with the caveats that even careful study of the laws and regulatory decisions may still have inadvertent omissions and that all of these programs continue to change.

The CPUC and the CEC are the two primary state agencies responsible for implementing programs to encourage the development, installation, and purchase of renewable electricity. These programs provide financial support through guaranteed revenue streams, incentives and rebates, and/or lower electricity bills. Utility customers, through their electricity bills, fund authorized, renewable energy programs, though federal tax incentives and federal stimulus (ARRA) funding also have provided important financing.

The CPUC's Division of Ratepayer Advocates (DRA)[8] recently issued a report describing California's renewable programs—aptly titled "The Renewable Jungle".[9] According to the DRA report, California currently has 11 different renewable programs,[10] all with different rules, duration, and goals.

No single law, regulatory decision, or document describes all policies and programs seeking to develop renewable power in the state, much less the many linkages (or lack thereof) among them. No plan has been developed to bridge the many gaps between planning, procurement, and permitting at the federal, state, and local levels. And, while dozens of decisions, laws, and reports show the state's strong support for renewables, no overall roadmap exists for the state's long-term renewable industry.

In 2002, the California Legislature (Senate Bill 1078) established California's first Renewable Portfolio Standard (RPS), requiring the state to meet 20% of its electricity demand from eligible renewable energy resources by 2010. Eligible resources include wind, solar photovoltaics, solar thermal, tidal wave, small hydroelectric, geothermal, biodiesel, biomass, and biogas.[11] Governor Schwarzenegger, by executive order in 2008, increased the renewable goal to 33% by 2020. The California Legislature passed SB 2 (1x) in 2011, codifying the 33% renewable target.

The level of on-line RPS renewables has expanded significantly in recent years. In 2010, California had more than 10,000 MW of installed renewable capacity, providing nearly 16% of total retail sales of electricity.[12] About 3,000 MW was distributed generation, with an additional 6,000 MW of distributed generation under development or authorized through existing programs.[13]

The IOUs have added significant amounts of renewables in recent years. Nevertheless, the gap remaining to meet the 33% 2020 requirement is large. SCE, for example, will have to increase its renewables by over 80% from 2011 actual deliveries to achieve the 2020 goal.[14] The following shows the progress to date and the amounts remaining:

TABLE 2: IOU Progress towards RPS Targets[15]

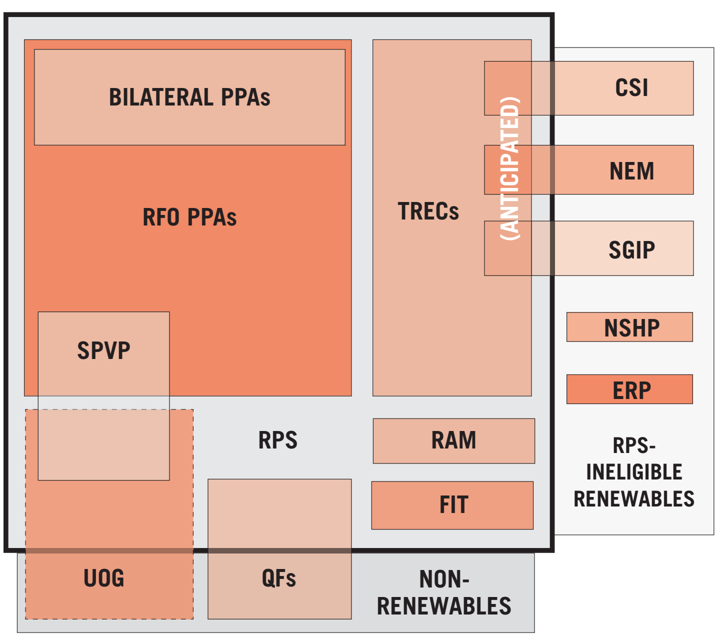
	Share of total load served by RPS resources				Gap to 33%
Utility	2002	2005	2010	2011	RPS target
PG&E	10.4%	11.9%	15.9%	20.1%	12.9%
SCE	17.0%	17.2%	19.3%	21.1%	11.9%
SDG&E	1.0%	5.2%	11.9%	20.8%	12.2%

While many of California's renewable programs procure power that is "RPS-eligible"—that is, the power procured counts towards the 33% RPS requirement—other programs are "RPS-ineligible," either because the energy produced under the program is difficult to measure or because it is not purchased by a utility directly.[16] One such example is

California's Solar Initiative program (the "Million Solar Roofs"), which subsidizes the cost of installing rooftop solar panels. The power produced is on the customer side of the meter and thus cannot be measured accurately since it offsets customer usage. Any excess power enters the electricity grid and goes through the utility meter. The excess power could conceivably be counted towards the RPS, though it does not. However, renewable energy production that is on the customer side of the meter lowers the amount of energy that the customer purchases from the utility and thus lowers the utility's overall RPS obligation, which is based on system-wide energy usage. A question going forward is how to develop an integrated approach between the RPS-eligible and non-RPS–eligible programs, including possibly having a single target that crosses over between both the utility and customer sides of the meter. The CEC has estimated that as of 2011, there were 127,000 customer-side solar projects, totaling roughly 1,300 MW.[17]

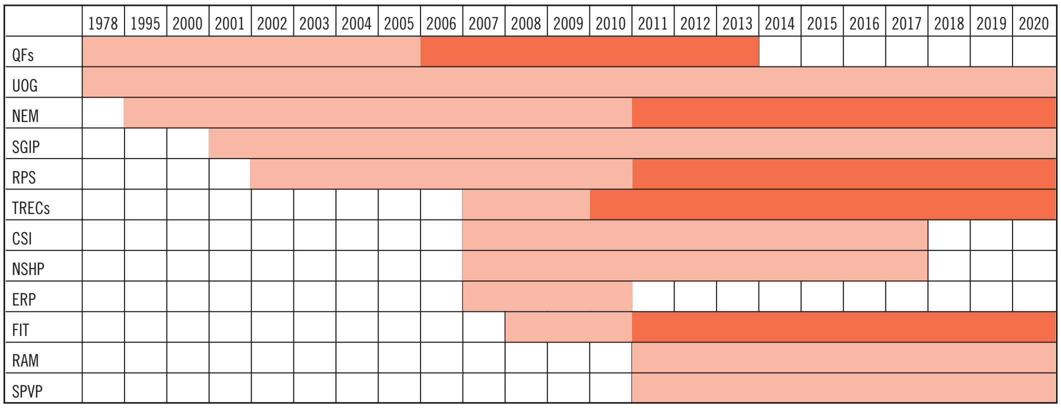
The figures and tables below, excerpted from the DRA Renewable Jungle report, illustrate the California policy web. Figure 1 depicts the complex overlap of various renewable energy programs and how they relate to each other, as well as those programs that are RPS-eligible and those that are not (and those that fall in-between, depending upon the actual power procured). Figure 2 shows the wide variations in the length of time authorized for each. As a further illustration of the complexity and overlap among the programs, Table 3 shows the renewable programs by technology and output. In addition to these procurement programs, the CEC, CPUC, and CAISO have multiple planning processes (such as the CPUC's Long-Term Procurement Planning docket) which are complex, not integrated under a single framework,

FIGURE 1: Relationship of Renewable Energy Programs[18]



CSI = California Solar Initiative
ERP = Emerging Renewable Program
FIT = Feed-in Tariff
NEM = Net Energy Metering
NSHP = New Solar Homes Partnership
PPA = Power Purchase Agreement
QFs = Qualifying Facilities
RAM = Renewables Auction Mechanism
RFO = Request for Offers
RPS = Renewable Portfolio Standard
SGIP = Small Generator Incentive Program
SPVP = Solar Photovoltaic Program
TRECs = Tradable Renewable Energy Credits
UOG = Utility-Owned Generation

FIGURE 2: Timeline of Renewable Energy Programs[19]



(a shade change indicates program expansion)

and—in too many instances—only loosely tied to procurement programs. Additional details of California's renewable programs can be found in Appendix I of this report.

TABLE 3: Renewable Programs by Capacity and Technology[20]

CA Renewable Programs by Capacity and Technology as of 2012

Capacity	Solar PV	Wind	Other
< 1 MW	California Solar Initiative (CSI) New Solar Homes Partnership (NSHP) Emerging Renewable Program (ERP) Net Energy Metering (NEM)	Emerging Renewable Program (ERP) Small Generator Incentive Program (SGIP) Net Energy Metering (NEM)	Net Energy Metering (NEM)
1–3 MW	Feed-in Tariff (FIT) Solar Photovoltaic Program (SPVP) Request for Offers PPAs Bilateral PPAs	Feed-in Tariff (FIT) Small Generator Incentive Program (SGIP) Request for Offers PPAs Bilateral PPAs	Feed-in Tariff (FIT) Request for Offers PPAs Bilateral PPAs
3–20 MW	Renewables Auction Mechanism (RAM) Solar Photovoltaic Program (SPVP) Request for Offers PPAs Bilateral PPAs	Renewables Auction Mechanism (RAM) Request for Offers PPAs Bilateral PPAs	Qualifying Facilities (QFs) Renewables Auction Mechanism (RAM) Request for Offers PPAs Bilateral PPAs
> 20 MW	Utility-Owned Generation (UOG) Solar Photovoltaic Program (SPVP) Request for Offers PPAs Bilateral PPAs	Utility-Owned Generation (UOG) Request for Offers PPAs Bilateral PPAs	Tradable Ren. Energy Certificates (TREC) Qualifying Facilities (QFs) Utility-Owned Generation (UOG) Request for Offers PPAs Bilateral PPAs

Likewise, the CAISO has expanded its activities in recent years, with seven separate initiatives relating to renewable and distributed generation now active.[21] Its role in the development of renewable and distributed resources is critical—covering development of rules on flexible capacity, backstop capacity authority, transmission planning, cluster review and interconnection, and valuing distributed resources. Yet, CPUC and CAISO coordination on procurement of projects and project interconnection and new transmission is ad hoc and needs major changes for streamlined, integrated renewable planning and procurement decision making. As noted above, the CPUC oversees renewable procurement programs, including approval of power purchase agreements (PPAs). But the CAISO has a completely separate and additional process for interconnection and deliverability. And, if the project needs new transmission, that can then entail a third and fourth round of regulatory approvals, through the CAISO transmission planning and then the CPUC's transmission permitting processes. Although the CAISO is not a state agency or a regulator per se, the renewable maze extends to its activities as well.

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Rising Utility Costs and Rates: Electricity "Sticker Shock"

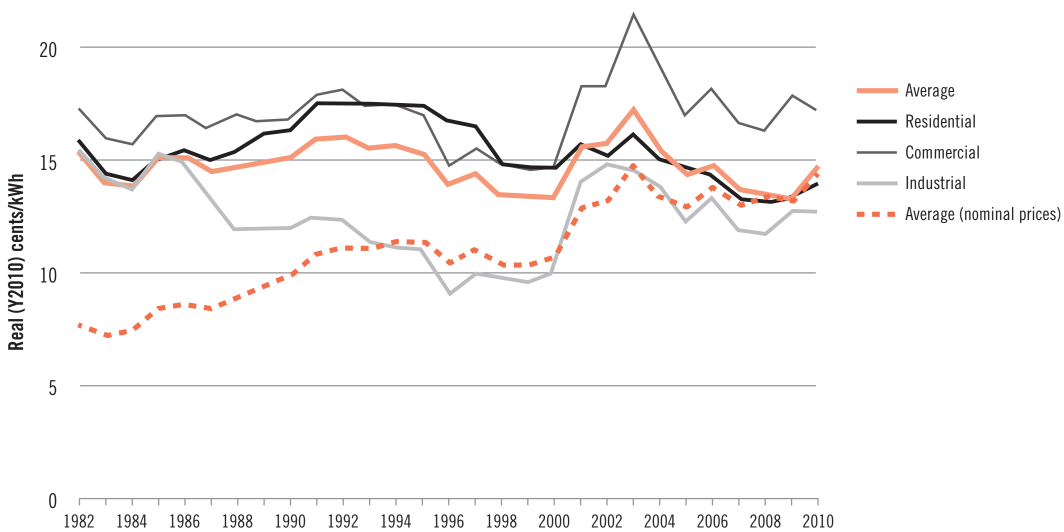
IOUs face significant cost growth over the next decade. These costs include new infrastructure investment to meet the electricity demands of a growing Californian population and economy, replacement of aging or non-useful infrastructure, and the additional costs of transforming the power mix to meet California's ambitious renewable and distributed power energy goals.[22] Looking ahead, California may be facing what at least one CPUC Commissioner calls electricity "sticker shock."[23]

But there is no public, current forecast of future costs, bills, and rates that uses updated assumptions of current (low) natural gas price expectations and California's electric system transformation goals, showing the full range of costs (and benefits). Cost, bills, and rate information is outdated, fragmented, and incomplete, limiting a full understanding of the path ahead and contributing to piecemeal program and project approval.

Overall Electricity Cost Increase Estimates

Both rates and bills matter in assessing costs. California IOU system-wide average electricity retail rates are among the highest in the United States but have remained flat or even slightly declined in real terms in every decade since the 1980s (apart from a temporary spike during the California electricity crisis).[24] California's electric bills, however, are lower than average, owing to energy efficiency efforts spanning three decades and relatively mild weather.[25] According to SCE, its average residential bills are lower than the national average, with residential usage 44% lower than the national average.[26]

FIGURE 3: California IOU Average Retail Electricity Prices, 1982–2010[27]



Most experts believe, however, that California IOU total costs and retail electricity rates will rise in the decade to come. Data compiled by the CPUC from publicly available documents shows that total statewide expenditure on electricity costs will grow by nearly 50% between 2010 and 2020. Of these forecasted costs, the largest share is for new transmission and distribution (much of which is driven by renewable needs), the second largest is for renewables, and the third is for new fossil fuel-related costs.[28]

Cost increases are not unreasonable, given the age of California's electric infrastructure, load growth, and the new features of the transformed system. However, there is a lack of current, comprehensive cost data and a strategic, integrated approach to minimize public and private expenditures. As explained in Box 2 and below, the existing forecasts differ widely in their projections, and overall understanding of potential bill and rate impacts is low. Even the CEC's most recent forecast (adopted in June 2012) entangles otherwise useful scenarios with outdated natural gas prices.[29] This cost growth will present major challenges in terms of both customer bills and rates at a time when the California state economy begins to emerge from the shadow of recession.

BOX 2: Estimating California's Rising Electricty Costs and Rates

Two of the most recent attempts to model California electricity system costs support an expectation of rising costs and rates. Even these estimates, however, are already out of date or lack specificity. They also omit or are incomplete regarding distribution grid upgrade costs and energy storage/demand response balancing costs.

CPUC Analysis:

In mid-2009, the CPUC, working with a team of consultants, analyzed potential costs for a statewide 33% RPS by 2020.[30] Key findings of the report were these:

- Total California electric system costs were likely to rise by 33.7% from 2008 to 2020 without any further renewable investment beyond 2009 levels.[31] These costs are due to maintaining and replacing aging transmission and distribution infrastructure, investing in advanced metering and other smart grid applications, meeting load growth, and implementing once-through cooling requirements.

- To meet the 33% RPS goal by 2020, total statewide expenditures were estimated to be an additional 10.2% above an all-gas scenario.[32]

- Together, this represented a total expected cost increase of 47.3%, with an estimated cumulative statewide capital investment requirement from 2008 to 2020 of $114.5 billion[33] to achieve the RPS mandate.

Since the 2009 study, two dramatic changes have occurred:

- *Solar PV prices have fallen dramatically.* When the 2009 study's model was run to reflect lower solar PV prices and significant distributed generation deployment, the cost premium to reach the 33% RPS target fell, to only about 6.3% above the baseline "all-gas" scenario.[34]

- *Domestic natural gas production has increased dramatically, and prices have fallen*. The 2009 study's baseline scenario assumed essentially constant natural gas prices of $6.57/MMBTU.[35] However, the report also modeled a "cheap gas" scenario (assuming $4.74/MMBTU) that now looks to be more likely. In this scenario the baseline total system cost rose by only 18.2% from 2008 to 2020. The RPS case was a 16.1% premium above this new lower baseline—in the range of the original 2009 estimate of costs without further renewable development. At the same time, the new gas assumptions led to more than 1.5 times the marginal expense to reach RPS goals than with the original "expensive gas" estimate.

These two changes—one lowering the expected cost of the RPS goal and the other showing significantly higher costs, compared to an all-gas path—illustrate how the economics of California's renewable goals can shift dramatically, based on outside factors.[36]

IOU Analysis:

In July 2011, the IOUs submitted in the CPUC's Long-Term Procurement Plan docket their estimate of 2020 revenue requirements, average rates, and total resource cost across the three major IOUs' combined service areas, given the 33% RPS, energy efficiency programs, transmission upgrades, greenhouse gas permit allocations, and other major adopted "baseline" regulations.[37] The IOUs' numbers estimate that RPS costs are significant, though not the major factor of rising future costs:

- Their combined service area annual total revenue requirement will grow from $30.4 billion in 2011 to $37.3 billion in 2020, a cost increase of 22.7%, with a net present value of total annual costs from 2011 to 2020 of $257 billion.[38]

- Their system average retail electricity rates in 2020 will be 0.189 cents per kWh, a 2.06% real annual rate increase over the next decade.[39]

- Their marginal annual cost of meeting the RPS mandate would be $1.46 billion in 2013 (about a 5% cost premium) rising to $3.51 billion in 2019 (about an 11% cost premium). It is worth noting that this RPS cost estimate is not clearly reported and can only be inferred through separate IOU filings.[40] The analysis further estimates the total cost component of RPS-eligible generation (but not new transmission, distribution, or other associated costs) at 20.8% of the 2020 total revenue requirement—an ongoing cost of $7.7 billion annually for those resources.[41]

These two changes—one lowering the expected cost of the RPS goal and the other showing significantly higher costs, compared to an all-gas path—illustrate how the economics of California's renewable goals can shift dramatically, based on outside factors.

Non-Renewable or Distributed Power Cost Growth

As shown in Box 2 and other public sources, a large amount of utility electric costs going forward will be from non-renewable activities. These costs include the business-as-usual expense of operating, maintaining, and replacing existing generation, transmission, and distribution infrastructure as well as demand-side investments. California utilities face unique costs in two areas: 1) costs due the statutory phase out of once-through cooling (OTC) technology in coastal power plants and 2) outage and other costs stemming from major equipment problems at the San Onofre Nuclear Generating System (SONGS). See Appendix III for details on these ongoing but still uncertain costs. These new costs—one arising from federal environmental requirements and the other from technology risk—are examples of the unexpected and non-elective cost drivers inherent in complex systems such as the California electricity grid. They illustrate the level of existing cost uncertainty that underlies the operating environment to which renewable and distributed power costs are now being added.

Renewable and Distributed Power-Related Cost Growth

Even without good public cost estimates, it is clear that state renewable mandates and goals over the next decade will contribute to utility cost growth. Along with technology costs, renewable costs include those related to permitting, interconnection, shaping and firming power, new transmission lines and upgrades, and distribution grid investments. Cost information is difficult to compile because California's renewable and distributed generation procurement efforts are split among 11 programs, thus making cost-growth forecasts extremely difficult. Non-technology costs are not tracked, in part because the costs are driven by many entities beyond the agencies overseeing the procurement programs and in part because future forecasts of these costs are subject to a wide range of assumptions. The CEC notes that there is substantial uncertainty about total system costs of California's goals and targets for renewable distributed generation.[42]

No single entity is charged with tracking overall costs. Estimates are further clouded because of stringent CPUC confidentiality rules. Moreover, while many studies provide levelized cost-of-generation evaluations, they do not adequately document how key assumptions were derived and how assumptions can lead to widely varying costs estimates, even though understanding these factors is essential to reduce the costs of renewable development.[43]

An area of particular concern is the lack of good cost data on upgrades needed to the distribution grid for distributed resources, electric vehicles, energy storage, and other elements of California's planned future. One credible estimate is an incremental amount nationally of $100 billion to integrate distributed renewable generation through 2030, on top of an estimated $675 billion for U.S. distribution investment. This incremental amount for distributed power integration is about 15%. A reasonable estimate for California's distributed power integration costs is 15–20% because of California's higher than national average distributed power goals.[44]

The renewable cost and spending estimates below represent an attempt to collect figures for California's 11 (plus 2 expired) programs in a single place, using publicly available data. They do not include distribution and energy storage costs. Inferring from the IOU cost analyses described in Box 2, above, the share of marginal costs of meeting renewable and distributed power mandates from these programs will be—roughly estimated—$45 annually for a typical household in 2013, rising to over $100 annually by 2019.[45] More details on program costs are available in Appendix II.

TABLE 4: California's Renewable and Distributed Power Program Costs[46]

	Program	Estimated Average Annual Costs
	RPS Power Purchase Agreements (PPAs)	**$2.00 billion** annually over 2003–2020
	Tradable Renewable Energy Credits (TRECs)	**$350 million** annually over 2010–2013
R	Qualifying Facilities (QFs) contracts	**$1.22 billion** annually over 2003–2020 *[renewable only]*
P	Utility-Owned Generation (UOG)	no major procurements to date outside of SPVP
S	Solar Photovoltaic Program (SPVP)	**$503 million** in UOG annually over 2010–2014, + PPAs
	Renewable Auction Mechanism (RAM)	PG&E expects **$124 million** annually over 2014–2020
	Feed-in Tariffs (FIT)	PG&E expects **$37 million** annually over 2015–2020
	Existing Renewable Facilities Program (ERFP)	**$25 million** annually over 1998–2011 *[program ended]*
	California Solar Initiative (CSI)	**$237 million** annually over 2007–2016
	Net Energy Metering (NEM)	cost estimates vary widely; **~$100 million** annually
	Self-Generation Incentive Program (SGIP)	**$81 million** annually over 2001–2014
	New Solar Homes Partnership (NSHP)	**$40 million** annually over 2007–2016 *[budgeted]*
	Emerging Renewables Program (ERP)	**$31 million** annually over 1998–2011 *[program ended]*
	Potential Total Annual Program Costs:	***~ $4.5 to $5 billion***

Prior to 2011 the Legislature, to some extent, limited the funds available to pay for renewable power. In response to concerns about expanding costs, the Legislature in 2011 set a new requirement for the CPUC to establish a cap for each IOU on RPS procurement expenditures.[47] If the CPUC cost limit is reached, the IOU may refrain from further procurement with more than a "*de minimis*" rate impact.[48] The CPUC is in the process of establishing the cost limit. But the filings in that case are highlighting how complex it is to forecast total RPS costs (including costs such as interconnection) and how much variation there is in assumptions. Furthermore, the cost limit will be only on RPS programs. The law does not address costs incurred by ratepayers in supporting the non-RPS programs. Thus, even with eventual adoption of a cost limit, California will not have a full picture of costs.

Cost Allocation: Uneven Cost Burdens on Utility Customers

The third stress emerging in California's move towards a transformed grid is in the arcane and extremely complex area of utility rate design known as "cost allocation". Simply put, the cost burdens on utility customers are uneven and of increasing concern due to the combination of non-cost-based rate tiers, increasing customer-sited distributed generation, and Net Energy Metering (NEM). Many parties recognize the problem, and there is almost uniform support for the state to modify its residential electricity rate structure to more equitably spread new costs going forward and fully capture fixed costs of providing electric service.[49]

As a result of California's disastrous electric deregulation attempt, the California Legislature has sharply restricted the CPUC's ability to set cost-based rates. Specifically, low-tier rate caps enacted during the California electricity crisis[50] limit electricity rate increases, despite growing costs, for low-usage and low-income residential customers. Simultaneously, IOU customers who are logistically and economically able to install

PV panels on their home rooftops can use the NEM program to effectively opt out of rate increases for higher electricity tiers, despite potential heavy consumption, and instead receive electric service at the protected low-tier rates net of their self-generation.

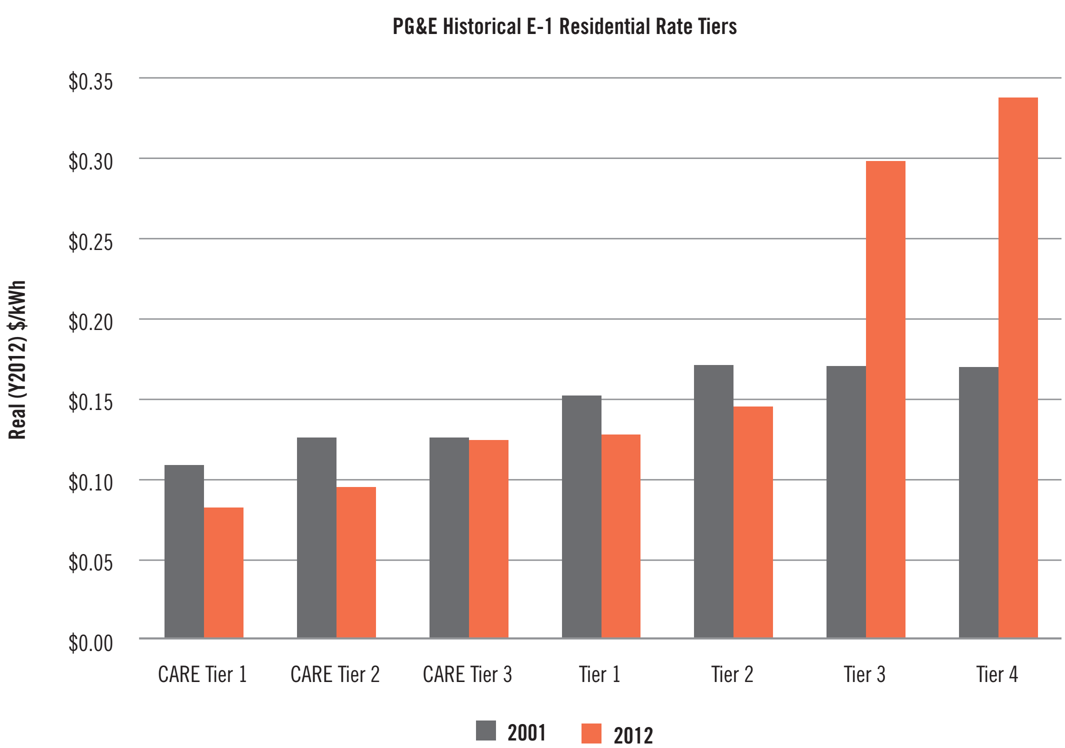
Absent reform, this rate design means that rising IOU costs in the residential sector are set to fall on a narrow base of customers whose incomes and consumption exceed rate protection but who do not install rooftop PV panels. In fact, though current policies are encouraging rapid PV deployment in the short term, the rate imbalances being created could actually limit the broader, market-driven scale-up of these key technologies by aligning utility and consumer interests against them. The Legislature, the CPUC, and the CEC have all recognized this situation, and the CPUC has launched a major proceeding in order to identify reforms needed to both residential and NEM rates.

Though current policies are encouraging rapid PV deployment in the short term, the rate imbalances being created could actually be limiting the broader, market-driven scale-up of these key technologies by aligning utility and consumer interests against them.

Rate Design for Low-Usage IOU Customers

Residential electricity customer costs include both fixed per-household costs (based on capacity availability, distribution infrastructure and maintenance, and billing services) and marginal use-based costs (such as fuel use, pollution abatement, and

FIGURE 4: The Rate Design Puzzle: Who Pays?[51]



generation costs). California IOU residential rates, however, are almost entirely marginal, with a four- or five-tiered pricing structure that increases the per unit rate above certain monthly consumption thresholds.[52] For example, a residential PG&E consumer in San Francisco pays $0.13 for the first kWh of electricity consumed in a month (a price which is below the IOU cost to provide that first unit of electricity). The payment almost triples to $0.34 for the 451st kWh (a price which far exceeds marginal delivery cost for that kWh). This rate design means that heavy users effectively cross-subsidize low-usage customers. And barring reform, future IOU cost growth will be passed through to residential consumers through marginal rate increases, even if the new IOU spending does not actually incur marginal costs in the delivery of electricity to a particular user.[53]

This problem is exacerbated because rates for lower-usage tiers have been essentially capped for the past decade through state legislation. As such, the difference among tier rates has increased. PG&E reports that rate caps on low-use tiers protect about 50% of its residential customers, accounting for 75% of total residential electricity sales.[54] This existing rate structure means that many of new system costs are passed through to that small share of the residential population with heavier consumption, who face the higher-rate tiers.[55]

Rate Design for NEM-Enrolled Customers

The California NEM provisions mean that those IOU customers who own homes and install rooftop solar PV are now subsidized as well. These customers are generally wealthier than the average ratepayer. They might have otherwise had monthly electricity loads large enough to put marginal consumption in higher-rate tiers. But through the NEM shift, they go from being net-subsidizers of IOU residential retail costs to net-subsidy beneficiaries.[56] This happens because once a household installs rooftop solar PV, its monthly "net consumption" often falls to within lower rate-protected price tiers. Considering once again the case of a heavy user in San Francisco, but who now owns a rooftop solar PV system with NEM, PG&E is effectively "buying back" excess electricity produced from that system at a marginal rate of $0.34 per kWh, which far exceeds the value of that electricity to the IOU. Recent evidence does suggest, however, that the rising popularity of third-party-owned residential rooftop solar systems is improving affordability for middle-income households; third-party ownership for CSI residential projects, for example, has grown from 7% of new projects in 2007 to 54% of new projects in 2011. At the same time, though, California home ownership has dropped.

From the perspective of participating customers, installing NEM-eligible rooftop PV systems is an economic benefit against their monthly bills, with larger systems saving consumers more.[57] PV systems can also hedge against future rising electricity prices, especially to the extent that those price increases are likely to be concentrated at higher-use rate tiers. But for customers who either cannot afford such systems, or who otherwise lack the ability to easily install them,[58] NEM rules concentrate growing IOU costs on an ever-narrower customer base.

A wealthier-than-average home-owning IOU customer—who might otherwise have large monthly electricity loads that would put marginal consumption in higher-rate tiers—can use NEM to shift from being a net-subsidizer of residential retail costs to a net-subsidy beneficiary.

While regulators must ensure that customer rates are both "just and reasonable," they are also charged with helping achieve California's ambitious clean energy and climate change goals. Likewise, consumers for the most part are unaware of the flaws in California's rate design rules. And utilities are increasingly concerned about not only the rate impact from NEM but also the erosion of their revenue streams. This third stress starkly illustrates the problem of trying to transform the electricity system without reforming the underlying framework and tools available to do so.

BOX 3: Drivers for California's Transformation of Its Electricity Sector

Dozens of laws, gubernatorial executive orders, self-originated CPUC policies, federal directives, local and regional initiatives, and a myriad of market and private investment decisions shape California's electricity sector and its rapid transformation. No single document catalogues these forces, and it is beyond the scope of this paper to provide a comprehensive list. Below, however, is a summary of key policy drivers:

California' Climate Change Law: AB 32, the Global Warming Solutions Act, requires California to reduce its overall GHG emissions to 1990 levels by 2020. The electricity sector accounts for 23% of California's total GHG emissions, with the commercial and residential energy sectors accounting for an additional 9%. Under the CARB's Climate Change Scoping Plan, emission levels for these sectors will need to be cut by 30% from a business-as-usual case.[59] AB 32 sets even more challenging goals for 2050—an 80% reduction in GHG emission levels from 1990 levels. CARB has taken a two-prong step to implementing AB 32. The first relies upon efforts that are set in specific policies and programs; the second is the establishment of a cap and trade system that seeks to reduce emissions beyond those achieved in the first. In the first area, the CARB has assumed that all of California's clean energy programs, including the 33% RPS, California Solar Initiative, and other efforts described below, as well as energy efficiency and demand-side efforts, will be successful.

California's Loading Order: A major foundation for California's advanced energy efforts is its "Loading Order Policy," first adopted by the energy agencies in the *2003 Energy Action Plan* (EAP) and continually followed by state policymakers since then.[60] The loading order provides that California, in meeting its energy needs, invests first in energy efficiency and demand-side resources, followed by renewable resources, and only then in conventional electricity supply. The Legislature has codified much of the loading order—by directing California utilities to implement "all cost-effective energy efficiency," by setting demand response goals, by limiting any long-term commitments to fossil-fired power plants, and through numerous directives regarding renewables. The loading order continues to provide policy direction in California and is often cited nationally and internationally.[61]

Continuing Effects from California's Deregulation Efforts: There are still major impacts from California's deregulation efforts of the 1990s. Ratepayers continue to pay hundreds of millions of dollars in transition, power, and bond charges and will do so until at least 2020.[62] The California Legislature has passed laws limiting further retail competition, and caps on residential rates that have now made residential rates non-cost-based are having a major impact on renewable development. The CPUC's Net Energy Metering (NEM) program is one focus area in the ongoing rates discussion.

Distribution System Upgrade Logistics: Integrating intermittent renewable resources requires a combination of complementary resources including energy storage, demand response, smart grid technologies, and flexible natural gas plants to provide the services needed to operate the electric grid safely and reliably.[63] Ongoing efforts throughout the state are attempting to resolve questions around local permitting, interconnection, the role of federal agencies, and municipal utility activities. Critical linkages must now be made between efforts on renewables and distributed generation with greater use of demand-side resources, energy storage, and changes in the distribution system, including greater transparency, automation, and open standards.[64]

Innovation, Employment, and Industrial Ambitions: California prides itself on being an international leader in energy innovation, entrepreneurship, and investment. According to a Brookings-Battelle data set, there are about 6,500 "green" companies in California. The San Francisco Center for Economic Development counts over 635 clean tech companies in just the San Francisco Bay Area alone. At the same time, California is suffering major impacts from the economic downturn, and as a result, there is a desire by many to use energy policy as a way not only to meet goals and ensure the efficient delivery of energy services but also to support in-state employment and industry development. These factors are influencing energy policymakers, as well as utilities, consumer advocates, and private companies.

INSTITUTIONAL CONCERNS

We have identified some of the key stresses that have arisen in California as the state moves toward its renewable and distributed generation goals: a web of complex programs, rising system costs, and controversial cost allocation. Left unaddressed, these issues potentially impede progress towards policy goals and/or negatively impact consumers. Of greater concern, these issues are symptoms of deeper root causes:

- California's outdated regulatory framework and
- California's outdated regulatory utility business model

Absent institutional reform in these areas, the stresses discussed above will grow.

The Regulatory Institutional Framework

In order to understand the institutional problems that exist, it is useful to review the change in the role of regulatory energy agencies. The changes are dramatic not only in California but throughout the United States. Thus, both the problems and the possible solutions are applicable for many, if not most, states.

> Simply put, the current system is inefficient, duplicates resources, creates confused jurisdiction, and is not transparent to the public.

For more than 70 years, the only state-level energy agency in California was the CPUC. Its role was a limited one of reviewing proposed utility rate increases and new power plant and transmission requests, most of which came infrequently. In California and elsewhere, most of the mid-twentieth century was a time of declining costs (due to economies of scale in power production and infrastructure) and rate stability. However, surging demand in the 1970s, coupled with limits on oil supply, led to dramatic increases in utility requests to build new coal and nuclear plants, with projections of skyrocketing customer rates and severe environmental degradation. As a result, the California Legislature established the CEC to provide a broader policy context, simplify power plant siting, and begin the first ever efforts on integrated resource planning and use of demand-side and renewable resources.

Fast forward through the 40 years since then, and we see a continual expansion of California's energy policy efforts and the roles given to state agencies to implement those policies, as well as the creation of a major new, non-governmental entity, the CAISO. Dozens of new laws have been passed and major changes are coming from the private sector in terms of additional energy providers (on both the supply and demand side), expanded sources of funding beyond utility rates, and new technologies and approaches. All of this means that every energy policy decision builds upon a complex set of laws, policies, and decisions already in place, involves a host of players beyond the utilities, and typically relies upon the actions of more than a single regulatory agency.

Yet, despite this tremendous change and the widespread commitment in California to transform the electricity sector, the institutional framework has not changed. That is, the energy agencies still make their own decisions separately, with coordination on an ad hoc basis. Each new law generally results in a new docket or proceeding and a new decision that is layered on top of prior decisions. The decision-making process itself still relies on the same approaches used decades ago—generally taking two years or more, involving extremely formalistic proceedings, and often far removed from the actual policymakers until the final days or weeks. While linkages sometimes are identified among cases, proceedings, policies, decisions, and agencies, no fundamental changes have been made in agency decision making, rule development, program implementation, or enforcement to meaningfully address such linkages. Instead, the typical response has been to add more issues into each agency's activities. Coordination among agencies is piecemeal and severely hamstrung by limited staff and siloed expertise.

BOX 4: California's Electricity System: Regulatory Agencies

California's energy regulatory structure is extremely complex. Historically, both California Governors and the California Legislature have been very active in driving state energy policy and specific programs, particularly renewables. There are four major state-level entities that are all responsible for major aspects of California's electricity structure—the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), the California Air Resources Board (CARB), and the California Independent System Operator (CAISO). In addition, there are a host of other governmental units, such as the California Environmental Protection Agency (CalEPA, which oversees the CARB), the California Water Resources Board, local governments and permitting agencies, and numerous federal agencies that affect key aspects of electricity, particularly renewable and distributed power development. Focusing on the four key entities:

California Public Utilities Commission (CPUC)

- 100-year old agency, established by Constitutional Amendment

- Five Commissioners, appointed by the Governor, approved by Senate; 1000 staff; traditional role is to ensure just and reasonable rates

- Rate-setting and utility regulatory authority have morphed CPUC from a reactive rate-setting agency to a proactive entity; it now sets or influences most of the key clean energy policies for the state and, through its rate-setting authority, funds most of the electric sector programs

- CPUC, through its decisions, approves the billions of dollars that are needed to implement California's new electric infrastructure

- CPUC regulates only IOUs, ESPs, and CCAs—and not POUs—thus limiting the players it can directly order to undertake activities

California Energy Commission (CEC)

- Established by the Legislature in 1973 to coordinate energy policy development, promote alternative energy and transportation efforts, and serve as a "one-stop" agency for licensing of new, large thermal power plants
- Part of the state's Natural Resources Agency, the CEC has no authority to set rates or raise funds; its budget and grant-making funds are provided by the Legislature or other sources
- Many of the California's renewable energy laws give a role to the CEC (in addition to the CPUC), generally in terms of overseeing RPS implementation by the POUs; the CEC has no direct regulatory authority over entities unless established in a specific law

California Air Resources Board (CARB)

- Deals with local air pollution but has also become a major force in California's energy efforts
- Lead agency charged with implementation of Assembly Bill (AB) 32, the Global Warming Solutions Act of 2006, California's groundbreaking greenhouse gas (GHG) reduction act

California Independent System Operator (CAISO)

- Not a governmental entity and, though created by the state, not subject to regulation or oversight by any state entity
- Regulated by the Federal Energy Regulatory Commission (FERC)
- Manages the flow of electricity across the high-voltage, long-distance power lines within the CAISO balancing area, which corresponds generally to the California IOU service areas; operates the wholesale power market, designed with the intent to diversify resources and lower prices
- Not required to take actions consistent with state laws or policies; has no mandates regarding renewable or distributed energy development
- Responsible for interconnection of generation to the CAISO-controlled grid, giving it a critical role in renewable development since any new interconnections to the CAISO-controlled transmission grid must follow the CAISO's rules and receive CAISO approval

In reviewing California's energy institutional structure and focusing specifically on renewable and distributed energy activities, these major areas of concern emerge:

- No single person or government agency is in charge of integrating efforts, and no roadmap for achieving California's ambitious goals—detailing needed decisions, funding, and schedules—exists.

- Multiple agencies have key roles, with overlapping responsibilities, differing goals, limited staff, and no streamlined process for addressing interdependent decisions, despite extensive coordination efforts.

- The programs being implemented are extremely complicated, with continuing changes in governing laws and agency decisions; no single source document succinctly describes the programs and their rules for participation.

- Public information on program status and costs is spotty and outdated.

- The institutional framework for distributed generation—a major policy goal of Governor Brown—is splintered among multiple programs, agencies, and efforts, with corresponding costs, inefficiencies, and gaps, as well as a lack of institutional structure for streamlined decision making.

Simply put, the current system is inefficient, duplicates resources, creates confused jurisdiction, and is not transparent to the public. We address each of the above problems in greater detail below.

> A number of people have likened the transformation of the electric sector to changing out an airplane while flying. For California, one can take the analogy further—a jet plane with no pilot (or rather multiple pilots, all running their own systems, on the same plane, at the same time).

No One Is in Charge of Integrating Efforts and Identifying Gaps

A number of people have likened the transformation of the electric sector to changing out an airplane while flying. For California, one can take the analogy further—a jet plane with no pilot (or rather multiple pilots, all running their own systems, on the same jet plane, at the same time, and in mid-air). If California is to achieve the fundamental transformation of its electricity sector that it seeks, it needs to have a single designated entity as the leader.[65]

The CEC has recently issued a draft Renewable Action Plan, requested by Governor Brown. This Plan is a good first step but more is needed. The Plan has 31 recommendations but does not prioritize them. Of the 31 recommendations, lead agency responsibility is split among the CEC, CPUC, CAISO, and utilities. There is no explanation of the linkages among the 31 recommendations in terms of sequencing actions, and the suggested schedule for each is very general. At a minimum, the next step should be to prioritize the recommendations, establish a schedule for decisions on an annual basis, and ensure that the CEC, if it is the lead agency in at least the short term, follows up on implementation. The document should also be expanded to be both a Renewable and Distributed Resources Action Plan, with a specific roadmap on the latter.

> If California is to achieve the fundamental transformation of its electricity sector that it seeks, it needs to have a single designated entity as the leader.

Agency Authority Overlap and Insufficient Coordination

In 2010 a laudable effort was launched, called California's Clean Energy Future.[66] The 2010 Clean Energy Future Overview recognized the need for agency coordination:

> [The major agencies—CalEPA, CARB, CEC, CPUC, and CAISO] recognize they cannot reach the Governor's clean energy goals for California without identifying their policy interdependencies and improving their communications and cooperation.[67]

However, the Renewable Energy section of the California's Clean Energy Future website has not been updated since March 2012. Indeed, the "Inter-Agency Road Map"—itself an almost unintelligible chart of agencies and activities—has not been updated for over two years. Continuing with the airplane analogy, California's approach is akin to building the new jet plane while in flight with no written set of instructions that everyone involved in the task has agreed to follow and in a given order.

> The "Inter-Agency Road Map"—itself an almost unintelligible chart of agencies and activities—has not been updated for over two years.

On a related note, no public document exists that describes the agency decisions needed by 2020 (and beyond) to achieve the state's energy goals, the interdependencies in agency decision making, and the specific time frame for all critical decisions. Likewise, no formal structure exists to link agency decision making or even communications, other than through formal evidentiary cases. Insufficient effort has been made to adopt faster, streamlined, more collaborative approaches to decision making, even though everyone involved knows the current pace and process is far too slow and cumbersome and does not allow for meaningful linkage across programs, dockets, and agencies.

Equally troubling, there are no overreaching criteria used to evaluate proposed policies and programs. Certainly, California's climate change law, AB 32, governs much agency attention, but the CAISO is not covered under AB 32. Likewise, the CPUC's mission includes ensuring reasonable rates, but it is also charged with balancing other factors and implementing many of the state's clean energy goals, with little or no linkage to cost limits or overall rates.

There have been efforts at institutional reform.[68] However, no effort has succeeded, due to at least two key factors. First, no agency has been willing to give up significant authority and has, either directly or indirectly, opposed restructuring. Second, no easy model for institutional reform exists since some features (the federalization of the CAISO and multiple locally owned and run municipal utilities) are outside the purview of state-led efforts. Nevertheless, continuing to rely on a pilotless model for California's energy transformation is increasingly seen as too risky a bet for the future.

Complex Programs with Constantly Evolving Rules

Over the six years 2006 to 2011, the California Legislature enacted over 40 laws dealing with renewable and distributed energy.[69] Key sections of the California Public Utilities Code were amended two, three, and four times. For example, four different bills combined with CPUC decisions and resolutions in various proceedings have designed California's current Feed-in Tariff (FIT) program, completely transforming its basic structure over time.[70]

During this same period, the CEC issued over 100 reports dealing with renewable and distributed energy policies, programs, projects, and rules.[71] The CPUC currently has six separate dockets setting the policies and program rules for renewable power development;[72] it has opened and closed at least three times that number in the last decade, and there are myriad related dockets.[73] In the last decade, the CPUC has issued over 50 decisions in its RPS and California Solar Initiative dockets alone. These decisions amend prior decisions, add new rules, and eliminate other rules, and no single document exists that describes the actual, currently applicable rules adopted by the CPUC for California's renewable energy development.

Likewise, the CAISO has expanded its activities in recent years, with multiple separate initiatives relating to renewable and distributed generation now active. Renewable developers remain concerned that the CAISO interconnection and transmission processes are a significant impediment and not well integrated with the CPUC procurement programs.[74] And CARB, through its AB 32 rule making, has established numerous rules (e.g., cap and trade, handling of allowances, combined heat and power (CHP) rules) that dramatically impact California's energy future.

Outdated and Spotty Public Information

No California law requires that information listed on a state agency website be current. In the energy realm, probably due to the number of agencies involved and the overwhelming complexity of policies and programs, the information is particularly outdated. As just one example, the CARB's website on its energy activities states that it was last reviewed in May 2012 yet cites a 2009 Governor Schwarzenegger executive order as directing it to adopt a regulation for a California 33% RPS—even though that order was overridden by California's landmark 2011 RPS legislation. In many cases, the most accessible source for updated information on California's renewable and distributed power programs and regulations is not a California government website but rather a third-party non-profit, based in North Carolina.[75]

> In many cases, the most accessible source for updated information on California's renewable and distributed power programs and regulations is not a California government website but rather a third-party non-profit, based in North Carolina.

No Coherent, Streamlined Framework for Distributed Power Development

A keystone of Governor Brown's energy policy is developing 12,000 MW of distributed renewable power—renewable power located near homes, business, and the communities it serves.[76] This is the most ambitious target for local distributed generation anywhere. Indeed, a recent report stated the following:

> Achieving the 12,000 MW goal and maximizing its benefits will not be easy. Development of local renewables at that scale will require a coordinated statewide effort to address a host of financial, regulatory, and technical barriers. It will require collaboration, creativity, and strong leadership to develop comprehensive and cost-effective solutions.[77]

Existing and authorized programs are projected to develop 9,000 MW of the goal; 3,000 MW will come from new or expanded programs. Yet, there is no agency document, state law, or executive order providing a comprehensive framework, identifying a single agency in charge of coordinating agency activities, or clarifying how conflicting policy outcomes regarding ratepayer costs, job creation, and timeliness will be balanced. The institutional structure and decision making that is central to achieving this goal has been largely ignored by policymakers with the exception of calls for streamlined permitting actions by local government, better CAISO rules, and expanded planning efforts. But far more is needed—development of a cohesive planning, procurement, permitting and investment framework; identification of responsibilities among agencies; integrated and streamlined decision making; and an implementation roadmap and schedule.[78]

> There is no agency document, state law, or executive order providing a comprehensive framework, identifying a single agency in charge of coordinating agency activities, or clarifying how conflicting policy outcomes regarding ratepayer costs, job creation, and timeliness will be balanced.

The Utility Business Model

Tensions between the Traditional Utility Business Model and Changing Electric System

In addition to fundamental weaknesses in California's regulatory institutional framework, the IOU institutional model is equally ill-equipped to lead this electricity system transformation. While rising costs and their allocation across ratepayers are significant challenges for both IOUs and the deployment of renewable and distributed power across California, they are but symptoms of an underlying problem. As new power technologies rapidly develop and societal goals evolve beyond just ensuring the supply of electrons, it now seems that the long historical precedent for the regulated IOU business model—even that set over the past decade of operating in California's "half de-regulated" electricity market—has become more of a barrier than an asset. In particular, those things that IOUs have a profit incentive to do are not necessarily the same things that society increasingly asks of them. For IOUs to remain major—though not sole—providers of electricity services to California customers, they will need new business models that align incentives and enhance risk-reward potential. And, to the extent they have the capital necessary to invest in major technological advances, the current regulatory structure typically disallows utility investments beyond traditional infrastructure.

The California electricity regulatory directive of "safe, reliable utility service and infrastructure at reasonable rates"[79] is one primarily focused on the mitigation of downside risk. For years, ensuring that the customer's light comes on when the switch is flicked without incurring too much financial pain has meant a deserved job well done. At the same time, IOU shareholders expect—foremost—steady, low risk, long-term returns from their investments. Even the term "utility" denotes a reliable, predictable investment. This dynamic has worked reasonably well for decades, but today's increasingly sophisticated and socially aspirational electricity system transformation goals are putting unprecedented stress on utility business models (which are based on increased revenues and utility shareholder profits with increased sales) and, at the same time, not aligning utility incentives and performance with support for new market entrants.

Energy Efficiency versus the Traditional Utility Business Model

The historical utility business model was simple: shareholder revenues increased with increasing electricity sales, typically from an expanding asset base of centralized generation and traditional delivery infrastructure. Energy efficiency is generally the least expensive energy resource for utilities, yet because it reduced utility electric sales and was not fully adopted by most utilities, IOU revenue and profit growth remained primarily linked directly to the construction of "steel-in-the-ground," rate-based infrastructure and the volume of electricity sales. Thus, absent change in regulatory policy, there is little incentive for an IOU to invest in demand-side energy efficiency even where the social gains of doing so are immense. Surprisingly, however, this tension remains even in California's uncoupled electricity markets, as described in Box 5, below.

BOX 5: Energy Efficiency and California's Risk-Reward Incentive Mechanism

California has been a leader in adopting innovative policies to align utility shareholder incentives with energy efficiency. Over twenty years ago, the CPUC "decoupled" IOU revenues from direct electricity sales and allowed IOUs to recover energy efficiency investments from ratepayers. In 2005, the CPUC, CEC, and CARB collectively adopted the California Energy Action Plan, placing energy efficiency at the top of California's "loading order" for energy system investments. But even with these changes, energy efficiency is not a "profit center" for IOUs, and thus California recognized that additional policy changes were needed.[80]

In 2006, the CPUC created a "risk-reward incentive mechanism" (RRIM) as an avenue for IOUs to generate shareholder returns. Under the program, IOUs can be penalized, left neutral, or rewarded[81] for the level of energy efficiency achieved among customers through a so-called "shared savings approach," in which shareholders are allocated a small percentage of the value of energy savings, as measured against predetermined annual savings goals. The ratepayers receive the remaining value of the savings, in the form of lower energy bills over time. Under the mechanism, if the IOU achieves more than 85% of its savings goals, the incentive payment ranges from 0 to 9% of the value of the energy savings. If the IOU achieves 100% or more of its goals, the incentive ranges from 9–12%.[82]

While utility incentive mechanisms like the RRIM can motivate utility management to engage in energy efficiency, they also provide an incentive for utilities to claim as much energy savings as possible in order to earn greater profits.[83] Significant controversy has arisen over how to "count" savings attributable to utility actions within RRIM and what is a "fair" distribution of the value of savings (or failure to achieve savings goals) between utilities and their ratepayers. The CPUC is undertaking an extensive review of RRIM, including whether to retain it and, if so, how to improve it. In the meantime, while IOUs have continued with energy efficiency, the level of uncertainty regarding RRIM is far from ideal, given the importance and urgency of energy efficiency as a core part of the California electricity system transformation.

This issue demonstrates how even the current, regulated IOU business model can be at odds with clean energy goals. And even where California has taken the lead in developing new regulating mechanisms to support utility energy efficiency efforts, these efforts remain incomplete, not integrated with other utility demand-side activities, and isolated from supply-side activities. It is critical to ensure that the utilities likewise do not have a business incentive to oppose demand reduction activities occurring in their service territories and that, if possible, their business models are aligned to support a portfolio of demand-side delivery mechanisms and service, including those from third parties. Mechanisms to encourage third-party competition or to open energy efficiency "procurement" to competitive bidding processes that mimic supply contracting have been used in other states and could potentially be used in California.[84] But until California and other states launch a full-scale review of the overall utility business model, even innovative efforts like RRIM are insufficient.

Innovation versus the Traditional Utility Business Model

California's energy system transformation depends upon an unprecedented level of innovation in technologies, grid systems, and new market entrants. Indeed, the very concept of the "smart grid" entails advanced grid infrastructure, new control and energy management systems, and two-way communication, as well as electric vehicles, microgrids, and energy storage. No such system yet exists, and while some elements are in use or in development, going from scattered pilots to comprehensive use in an electricity system for the eighth largest economy in the world, while necessarily remaining reliable, secure, and affordable, requires a massive integrated effort that cannot simply be mandated into existence.

Yet, as with energy efficiency, the traditional regulatory model penalizes innovation and risk-taking activities by utilities. Utility-owned assets must be "used and useful" to be in utility rate base and provide a rate of return. Likewise, many utility actions are judged by an after-the-fact "reasonableness" review. While these mechanisms have provided needed protection to ratepayers, they also deter utility innovation; they limit both new utility roles and investments in emerging technologies and IOUs' ability to capture for shareholders the economic value of new high-potential investments. Together, this means that the pace of operational and technological innovation among IOUs is slow.

BOX 6: California's Answer: Public Funding for Electricity R&D

California has been a leader in supporting ratepayer-funded R&D to fill the gap left by IOU shareholder R&D funding after restructuring in the late 1990s. For over a decade, California ratepayers and taxpayers funded the Public Interest Energy Research (PIER) program, administered by the CEC. Because authorization for the public goods charge that funded PIER recently expired, the CPUC established this year a new "electricity procurement investment charge" (EPIC), at a similar funding level of about $143 million annually. Twenty percent of the EPIC is set aside for administration by the IOUs (with CPUC oversight) "for applied research and development, technology demonstration and deployment, and market facilitation for clean energy technologies and approaches for the benefit of ratepayers."[85]

Even with PIER—and now EPIC—R&D investment in California and the electricity sector in general is seriously lagging. The U.S. Department of Energy's $650 million demonstration funds have largely been expended, precipitating, as noted in a recent report by The Resnick Institute at Cal-Tech, a "funding cliff for grid modernization research, including for development and demonstration."[86] The EPIC R&D investment level equates to 0.4% of total IOU gas and electric revenues. The UK's electricity regulator, Ofgem, in contrast, has targeted R&D spending at 0.5% of utility revenues for distribution utilities alone.[87] It is worth asking if the needs of California and the nation's grid modernization R&D require not just public funding but also direct profit mechanisms available to IOUs for R&D investments. Given the extremely low levels of R&D investment in the electricity sector, there is likely ample potential for competitive return on investment from both public programs and private spending—even before considering the serious transformational goals of the California electric system.[88]

A lack of flexibility and incentive misalignment inhibits IOUs' innovation potential in not just investment but operations as well. One example of this is the slow implementation of new rate designs, such as time-variant pricing, which would encourage customer demand to respond more closely to the cost of electricity supply. Instituting default "symmetric load treatment" pricing mechanisms, such as critical peak or hourly pricing, across IOU customer classes could reduce California peak loads on the order of 10% and reap net social benefits from improved system efficiency,[89] as well as increase the value potential of distributed generation in competitive markets. Though deregulation experiences suggest that the benefits of symmetric pricing in electricity might accrue largely to ratepayers,[90] the risk that symmetric pricing would raise prices for some IOU customers in some cases has generated resistance from consumer groups to support such change. And despite significant potential social savings, California IOUs, who do not face an obvious profit incentive for broadly implementing dynamic pricing, have also only tentatively approached the issue.[91] If IOU shareholders—or other third-party entrants—were able to better share in the efficiency gains of implementing dynamic pricing, then progress on this important issue would likely be faster.

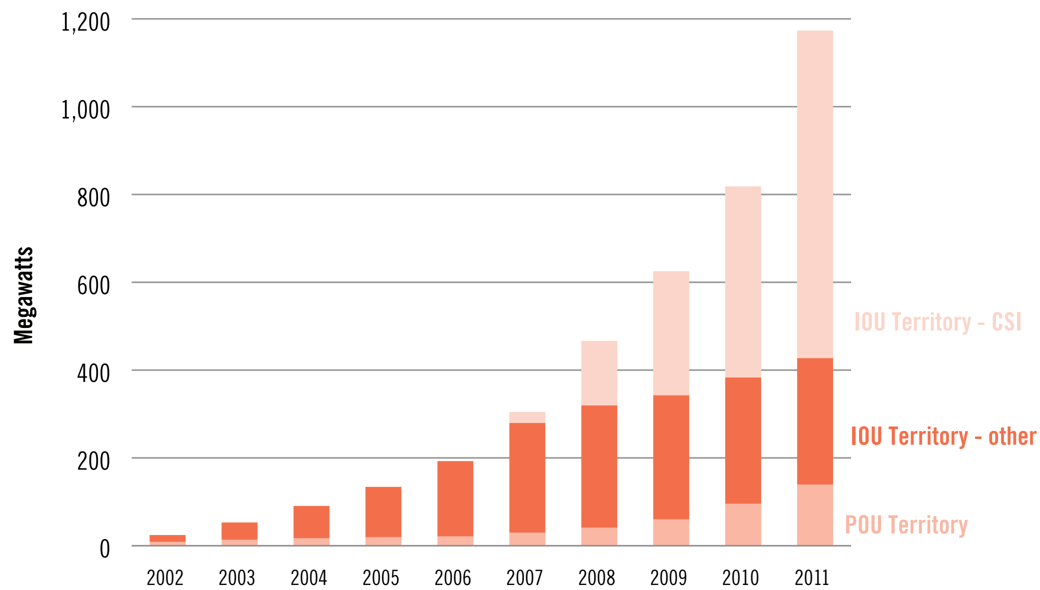
Distributed Power as a Game-Changer

Already, Californians' growing investment in distributed power is changing dramatically the role of utilities and their business returns and providing expanded opportunities for non-utilities in areas of service previously reserved to the utility monopoly. Despite legal prohibitions on retail competition, IOU customers are electing to become their own service providers—even with the considerable difficulties inherent in local permitting and installing thousands of small, capital-intensive, intermittent generation resources.[92] Residential customers in California are adopting rooftop solar PV systems at exponential growth rates, despite decreasing direct installation subsidies, enabled by falling component and transaction costs.[93] Larger commercial customers are similarly motivated, and the nature of their load is attractive for emerging distributed power technologies such as fuel cells, combustion engines, on-site gas microturbines, and advanced storage. Additionally, with the abundance and low pricing of natural gas, combined heat and power (CHP) applications are likely to rise though the impact in California will be affected by air quality rules.

Though today's user-side of the meter "distributed generators" remain IOU customers, every kilowatt of capacity that they install now decreases IOU sales and potentially caps future IOU market potential. Likewise, customers are increasingly able to modify and reduce their loads on the demand side. After a century of *de jure* "natural" monopoly over electricity sales, technology is providing a disruptive pathway for *de facto* market entry and new retail competition.

After a century of *de jure* "natural" monopoly over electricity sales, technology is providing a disruptive pathway for *de facto* market entry and new retail competition.

FIGURE 5: California Customer-Sited Solar PV Capacity[94]



BOX 7: Prospects of Distributed Power Systems (DPS) in the United States

Advocates of DPS see them as a means of harnessing local sources of generation to let consumers bypass the centralized system of generation and dispatch and, in many cases, to meet their own electricity needs. They see DPS as having the potential to stabilize and support the grid by relieving congestion, while deferring or avoiding the construction of new centralized power plants by offsetting end-user demand. They also highlight the ability of many distributed technologies to increase the efficiency of power delivery through avoided transmission and distribution (T&D) losses, reduced capital expenditures on T&D, the conversion of waste heat and energy to useful power, and the ability to harness distributed renewable resources through systems such as rooftop solar installations. Others stress their potential to decrease electricity system vulnerability through the diversification of the power supply portfolio and the “islanding” of generation and distribution. The most ardent supporters of DPS see them as holding the potential to revolutionize the U.S. power sector through the replacement of the existing power system with new, local markets for electricity, based on networks of small-scale generation and informed consumption.

Critics of DPS highlight the high cost of distributed sources of power generation relative to centralized power stations and the danger of subsidies and incentives for DPS technologies creating unsustainable industries. They also point out the negative disruptive effects of attempting to integrate small-scale generation and storage systems into a power infrastructure not designed to accommodate them. In a sector that depends more than any other on predictability and reliability of operations, they argue, any attempt to move away from a highly centralized and controlled system to a new paradigm based on the aggregation of numerous, independently run assets comes with enormous direct and indirect costs.

Quoted from “Distributed Power in the United States: Prospects and Policies,”
The Hoover and Brookings Institutions, 2013

The potential positive impacts of broader distributed power technology deployment on greenhouse gas emission mitigation, grid resilience, fuel flexibility, and even industry development are now widely discussed.[95] But perhaps just as important for California, given the enormity of challenges facing the IOU-dominated electricity supply system over the next decades, are the potential impacts of distributed power deployment on improving electricity market efficiency and function.

In their regulated, natural monopoly state and through their ownership of the grid distribution system, California IOUs have historically faced little substantial competition from new market entrants. Electric Service Providers (ESPs), described above, have limited CPUC-granted authorization to retail electricity directly to end-users over the IOU distribution system through "direct access" provisions. Community Choice Aggregators (CCAs), such as the Marin Energy Authority operating in the San Francisco Bay Area, allow city or county residential and commercial customers to aggregate voluntarily their electricity demand to purchase directly the wholesale power of their choosing and determine independent rates structures. But both these forms of IOU competition are still highly restricted and do not have access to the same IOU market rules, limiting their scope.[96]

The deployment of distributed power among retail customers, however, may radically change the face of utility competition, depending on how state regulations are developed to enable or impede these technologies.[97] In fact, distributed resources have already started to change the landscape and compete against some utility services:[98]

- IOUs may avoid wholesale power purchases or defer investment in generation or transmission grid infrastructure.[99] At the same time, development of new distribution grid technologies and significantly increased IOU distribution investment will be critical.

- Going further, as distributed technologies improve—particularly in storage and power electronics—customers (either individually or through aggregators) will provide shaping and firming, voltage regulation, and other ancillary grid services for themselves, the grid, and potentially local microgrid operations.

- California's goal of moving towards "zero net energy" buildings will further erode utility sales and investments and empower customers. Likewise, proliferation of two-way communication systems at the customer and distribution level will change dramatically the role of the customer vis-à-vis the utility provider.[100]

Over time this increased customer autonomy can be expected to diminish IOU market dominance. At the same time, the line between wholesale and retail markets will blur in order to properly value expanding localized services, such as the development of localized balancing areas and distribution-centered markets.

State regulators will be central to determining how distributed technologies affect the electricity market framework. In particular, to the extent that utility services and rates can be disaggregated into discrete elements with flexible enrollment, self-generators will be able to modularly invest the capital and operating expenses required to meet their electricity supply preferences without distorting broader utility costs across non-participating customer classes. Today, such service modularity and flexibility is not available despite rapid distributed power growth across the state. And though California's regulatory treatment toward pricing distributed generation (i.e., NEM) supports deployment of these technologies in the short term, unequal social impacts run the risk of turning this promising game-changer to yet another marginal player within the utility ecosystem.

The gaps and overlaps in California's energy regulatory structure also come to the fore with increased use of distributed resources. On the project development side, the current system of procurement through CPUC programs, project permitting through local governments, and interconnection through both CPUC and CAISO processes leads to increased costs, delay, and confusion. Absent integration of planning, procurement, and permitting into a single, streamlined system, these problems will only increase.[101]

A final area of concern is the likelihood of increased reliability and resiliency risks in an electric system relying upon large amounts of distributed resources. Understanding and mitigating these risks is paramount. But the current system of divided agency responsibilities for distributed resources and an outdated utility business model mean that these risks are not given adequate attention and that no comprehensive plan is being developed.

For all of these reasons, change in both the regulatory structure and the utility business model is imperative in a future of broadly deployed distributed power systems.

OUR SOLUTIONS FOR CALIFORNIA: INCREMENTAL AND FUNDAMENTAL REFORMS

Changes in regulatory and utility institutional structures are fundamental to the successful development of a new electricity system, especially one as complex as that envisioned for California. In this section, we set out two approaches. The first focuses on addressing the stresses we have identified—rationalizing the complex renewable policy web, mitigating cost and rate challenges, and addressing inequitable cost allocation structures. The second approach is more fundamental, reforming the underlying regulatory and utility business model. The path chosen depends upon the political will in California and the urgency with which this issue is viewed. Regardless of that choice, policymakers and stakeholders need to begin an in-depth discussion of these issues and ways to address them, in order to ensure that these critical institutional factors do not undermine the stability, affordability, and low environmental impact of California's electricity system.

Incremental Solutions: Treat the Stresses

Rationalize the Complex Renewable and Distributed Power Policy Maze

Many of California's current programs to promote renewable and distributed power are technology- or scale-specific. But even the best such programs cannot anticipate exact changes in new energy technologies or market conditions. As a result, the California policy and programmatic landscape remains a step behind the market, forever in a state of regulatory fine-tuning or major overhaul as new market forces, players, and programs emerge. Here, in order of increasing ambition, are four ways to help rationalize the web of programs:

- *Require all renewable and distributed power policies, programs, and rules to be consolidated into a single document, updated semi-annually.*

  Given that California government agency websites do not currently publish up-to-date information about existing electric power programs and that wide-reaching inter-agency reports are out of date by the time they are published, there is an immediate need for a straightforward, one-stop information clearinghouse that stakeholders can consult to learn what polices and programs, with what rules, are in effect or will be coming into effect. This document should be organized by program and integrate all policies rules and agency roles for each program, combining in a single place all rules by all agencies and the CAISO. As needed, the agencies (and the CAISO) should formally adopt the document so that it provides the clear "rules of the road" to all stakeholders.[102] And, each agency should review applicable policies and programs annually to ensure that each are responding to market forces, set forth a viable path for the state's renewable industry, sunset when appropriate, and implement a coordinated set of goals.

- *Designate a lead agency charged with developing, in conjunction with other agencies and the CAISO, a roadmap for the achievement of California's renewable goals.*

  The initial steps set forth in the "California Clean Energy Future" and the CEC's draft Renewable Action Plan need to be taken much further. An actual roadmap is needed, identifying the steps and decisions needed by each agency to achieve success in its respective role, the timeframe for taking those steps, and processes to ensure inter-agency/stakeholder coordination in a timely manner. The roadmap should also seek to have joint or coordinated decision making between entities, to streamline and align programs.

- *Develop a plan for distributed resource development (or issue an executive order or inter-agency memorandum of understanding) setting out goals, policies, programs, costs, and funding and implementing responsibilities and a decision-making schedule across agencies and programs.*

  California's approach to distributed resources needs to be solidified and the roles of state agencies and the CAISO clarified, including the selection of a lead agency for tracking success in implementing the goals. The document needs to incorporate planning, procurement, and permitting efforts and programs, across agencies, with a unified cross-agency schedule for resolving issues and streamlining agency decision making.[103] This document should be updated annually and should, through a single website, publish information on costs, success in implementation, and issues needing resolution. A key issue to be addressed is the integration of RPS-eligible and non-RPS–eligible programs, including the possibility of a single target that crosses over between both the utility and customer side of the meter.

- *Limit legislative addition of new, renewable programs unless done to address governance and institutional issues.*

  California has more renewable laws and programs than any other government. Given limited government resources, a hiatus should be taken on developing new programs on a piecemeal basis. Agency attention should be on integrating efforts, streamlining programs and decision making, and developing paths to provide long-term sustainability.

Assess and Respond to Costs

While declining solar PV prices are driving down renewable costs, and low domestic natural gas prices are mitigating overall power system costs, more can be done to ensure that the state's path forward on renewable and distributed energy is affordable. Rising cost, in itself, is not an inherently unacceptable phenomenon in all situations; rather, it is a lack of explicit cost expectations—information and metrics—that makes rising costs so troubling. Without understanding the costs, taxpayers and ratepayers cannot accurately weigh them against the benefits being provided. And while government does not control fuel or technology prices, it is responsible for the policies and program designs that drive power system costs. Additionally, though competitive markets can provide cost discipline, it is unclear how the many California policies and programs sustainably support new market entrants. Here, in order of increasing ambition, are four ways to help fix this:

- *Continue California's aggressive pursuit of energy efficiency and demand-side measures to offset supply costs and lower customer bills.*

  California has been the leader in implementing energy efficiency, and 30-plus years have shown the success of its programs in lowering consumer bills. California should continue this approach, as a key measure to mitigate rising costs on the supply side. Neither the CEC forecast nor the CAISO's planning assumptions currently include the full range of efficiency savings that the CPUC has set as IOU targets. Such savings should be included, to avoid planning and building unneeded infrastructure.

- *Improve the public availability of cost data and track total costs.*

  Too often, "knowns" become "unknowns" in the California electricity system through heavy redaction in public documents—especially data related to utility spending and cost estimates. In many cases, the only ones who do not know the price of something—the public—are the ones who are paying for it.[104]

- *Undertake a review of rebates and incentive mechanisms for renewable and distributed power programs to ensure that public funds are used in a strategic manner to drive down costs and potentially cap public subsidies over time.*

  The California Solar Initiative offers a model of long-term support through a program that consciously decreased government subsidies over time, to send clear signals of a long-term market that would, by lowering solar technology costs, replace government subsidies with private investment. Similar approaches are needed in all renewable and distributed power programs, with a clear articulation of the generation technology cost-lowering strategy at time of program approval, and with regular reviews and updates during the program lifetime.

- *Understand and respond to systemic risks that can significantly drive up program costs.*

  California is facing at least two major, systemic risks in its renewable push—the potential loss of federal tax credits and delays in major, new transmission lines that could jeopardize renewable development clusters. To date, regulators have not identified these as systemic risks nor articulated a clear strategy to deal with such risks in a timely and cost-effective manner.

> Too often, "knowns" become "unknowns" in the California electricity system through heavy redaction in public documents—especially data related to utility spending or cost estimates.

Address Uneven Cost Allocation

We have seen how electric system costs are unevenly allocated across different customer segments—even within the residential sector—and how, absent reform, future cost increases will fall on an increasingly smaller segment of electricity users. Both the Legislature and the CPUC have recognized that cost allocation must be changed for a viable approach going forward. Without proposing specific rate design mechanisms—CPUC proceedings on such issues are ongoing—we suggest, here, some principles to focus cost allocation discussions:

- *Ensure adequate resources for the Division of Ratepayer Advocates (DRA) to act as a key voice for residential and small commercial customers in areas of revenue allocation and rate design.*

  DRA was set up within the CPUC to act as a voice for electric utility customers in the drawn-out, formalized CPUC public hearings process. California should provide DRA adequate resources to represent IOU electric residential and small commercial consumers regarding the development of fair cost-shifting and cost allocation structures to ensure that the CPUC meets its statutory charge to set utility rates that are not just "reasonable" but also "just."

- *Identity tariff and rate design changes that address inequities of renewable and distributed power ratepayer cost allocation and identify approaches that maintain broad support for expanding distributed generation.*

  Despite a basic principle of setting "cost-based" rates, non-cost-based rate designs have in fact repeatedly been created over the past decade in California. In response to concerns over NEM pricing in particular, the Legislature has passed AB 2514, which requires the CPUC to examine the costs and benefits of the NEM program. One solution for NEM may be to meter the PV output and pay the customer a different rate for that output than the retail charge for electricity. At the same time, the CPUC needs to continue its review of residential rates to avoid unfair subsidies and ensure broad-based support and sustainable cost-sharing for California's expanding use of distributed resources.

Fundamental Solutions: Reform the Regulatory and Business Environment

Establish Clear Agency Responsibility and Use a Consistent Set of Policy Decision-making Criteria across Agencies and Programs

In the middle of the past decade, following the California electricity crisis and concerns about agency gridlock standing in the way of investment in new, long-distance transmission lines, Governor Schwarzenegger proposed to create a California Department of Energy that would centralize administrative functions, reorient and streamline CEC decision making, and narrow the focus of the CPUC. Though many groups supported this attempt at improving agency accountability and decision making, it ultimately failed because of legal technicalities and uncertainty around the policymaking role and other responsibilities of the constitutionally chartered CPUC. Overall, however, the Governor's proposal recognized the need to reform the state electricity agency institutional framework in order to support desired transformations of the physical grid. And while the proposal was concerned with grid reliability and ensuring enough supply investment, today we too see the need for agency reform to support California's broader renewable and distributed power-oriented physical transformation goals. Here are some potential ways—ranging from most basic to the more ambitious—to get there:

- Expand the CEC's Renewable Action Plan to identify, in greater detail, agency roles, decisions, scheduling milestones, and distributed power framework/coordination; adopt key components as an executive order; and hold public quarterly, interagency meetings to report on milestones met.

- Develop new legislation to set up a single agency, simplify programs and roles, require public roadmap and milestones, and direct the use of collaborative problem solving.

- Reorganize and integrate rules and decision making for both utility-scale renewables and distributed power.

Central to fundamental reform is identifying and using a consistent set of policymaking criteria by all agencies and entities involved in promoting California's renewable and distributed resource efforts. Today, each agency follows the approach it thinks best and further subdivides that, based on the program being addressed. A single, well-understood set of criteria is needed to ensure consistency across planning efforts and procurement programs. Examples of four possible criteria are environmental benefits, ratepayer costs, reliability impacts, and economic development benefits.

BOX 8: Looking Ahead: Challenges and Opportunities

This paper has demonstrated reforms that would clearly benefit California as it moves towards its near term 2020 goals for renewable and distributed power. Absent such action, these targets might be reached, but in a messy and potentially risky way. The dramatic steps that would be needed to meet California's 2050 climate change target, however, exemplify how the institutional framework must be fundamentally updated in the longer term.

An article this year in Science Magazine[105] analyzed the immense scale of infrastructural changes needed to meet California's 2050 target of an 80% reduction in GHG emissions below 1990 levels.

Its findings reinforce the fact that the current ad hoc agency coordination and outdated utility business model is inadequate for the system-wide changes needed. The study's detailed modeling suggested the following:

- Cumulative investment needs of $400 to $500 billion in current dollars for unprecedented energy efficiency, decarbonized electricity generation capacity,[106] and electrification of transportation and other sectors—a factor of about 10 higher than in the baseline case.

- With transportation electrification, electricity would increase from 15% to 55% of California's end-use energy. The cost of decarbonized electricity would thus become a paramount economic issue and *"minimizing the cost of decarbonized generation should be a key policy objective."*

- The sequence of deployment for the major components of the transformation could greatly affect costs: *"Not only must these technologies and systems be commercially ready, but they must also be deployed in a coordinated fashion to achieve their hoped-for emission reductions benefits at acceptable cost."*

- Transportation electrification could help maintain utility revenues (and thus be a key component of future utility business models) but "smart charging" and rate reforms to raise utility load factors and reduce peak capacity requirements must accompany it.

Such a transformation clearly demands a new paradigm for electricity regulation and business. Whatever the choices California makes over the next half-century, challenges of this scale lay bare the importance of working with solid fundamentals from the beginning. The renewable and distributed power goals that we already have today, near at hand yet still full of uncertainty, are an opportunity to show that California can get it right.

Rethink the Role of the Utility and Other Electric System Players, Given Modern Technology and Market Possibilities

Distributed generation, smart demand response, and dynamic bi-directional information flows are already reshaping the utility-customer relationship in California. But the pace is slow, and any change is incremental. This is in part due to the lack of a compelling business case (for the utility) or value proposition (for the customer) to fully embrace the costs and risks of developing new utility-customer interaction and revenue paradigms that could support these new technologies and services at scale. Likewise, California has not articulated a vision for the long-term role of non-utility entities in the new system, ranging from utility-scale renewable developers to local providers of distributed generation to developers of advanced hardware/software systems. In many ways, these tensions are similar to those under California's deregulation attempts two decades ago—is California seeking a system that remains utility-focused albeit with changing utility roles and services, or is California developing a system with a smaller monopoly-utility role and greater services provided by a competitive market? Beginning this discussion and understanding the tradeoffs in the differing paths forward is critical.[107]

> Ultimately, the technological advances that have already put renewable and distributed power systems within reach of California and other states must be matched by advances in regulation and business.

- One incremental step in the right direction would be for *CPUC to adopt an incentive framework for utility innovation,* recognizing that risks and returns might come from investments in operational changes, from software, or from other areas. Because the CPUC regulates a large share of utility investments, it can reasonably increase utility investments in innovation needed to meet California's renewable and distributed power goals. This change in itself will not transform the utility business model, but it will help equip utilities to do their jobs better. Ultimately such an incentive framework may even help utilities to develop new options and directions for more fundamental transformation in the future. At the same time, if such new investments are to be of any reasonable size, it is important that utility customers are not left responsible for downside risks (that is, the initial cost of a failed investment) while shareholders enjoy only the upside. Both risk and reward must be shared between ratepayers and shareholders.

- Beyond this first step, more ambitious efforts are needed from both policymakers and utilities in experimenting with new grid management, customer interaction, and revenue models. For both grid reliability and utility business viability, alternate models must be well understood so that they can be seriously evaluated. It is not clear that such learning can take place through incremental adjustments in the present electricity system. Therefore, to improve utility and policymaker confidence, California should consider the *establishment of regional pilot projects in the short term, transitioning to designated distributed power / new electricity system regional development zones over the medium term,* preferably through voluntary enrollment by existing interested communities or through application to new-built areas. *Over the longer term, as viable alternate regulatory and business frameworks are identified, they could be instituted through a transitional parallel-track system alongside the "legacy" framework,* much in the same way that many planned economies have reformed, transitioned, and opened individual sectors to successfully perform in new market conditions.

- Given that markets, technologies, consumer preferences, and political ambitions can all change rapidly, what should be the unifying lens through which utilities and policymakers can consistently focus their efforts at fundamental institutional reform? *Distributed power should be that forcing agent for institutional reform,* in California and elsewhere, because it represents a crystallization of changes and priorities that customers are already adopting but which are alien to those utilities (or policymakers) who are wed to the traditional central station, long transmission, monopoly-distribution, unidirectional, rate-based, low cost, basic-performance electricity service delivery paradigm. Its very contrast—in terms of technology, pricing, and service—with the established model will help focus on the changes that are needed. Moreover, customers are already demanding it, whether or not utilities are ready.

- Another key item to address in reviewing the basic utility business model is California's vision for non-utility players. California has for decades supported a competitive approach to procurement, including renewables, distributed resources, and demand response. *New players can bring investment and innovation beyond that provided by utilities and thus need to be considered key in California's new electric grid*. However, the state policymakers have yet to have a meaningful discussion—much less a roadmap—on steps needed to align a sustained, profitable business model for new, non-utility entrants that also broadly aligns with the changing utility role. Below in Box 9 is a vision of two alternative utility models. Of these two models, the latter—the utility as a smart integrator—best aligns with support for non-utility entrants and the direction California has been moving towards.

BOX 9: Two Potential Alternative Utility Models

The Energy Service Utility:

An "energy service utility" is an extremely vertically integrated one (drawing back to a model envisioned by Thomas Edison) that would provide not just kWhs but the actual service itself of "cold beers and hot showers."

The social appeal of this would be an IOU with financial incentives aligned to realize significant efficiencies by optimizing every aspect of both electricity supply and consumption. An energy service utility that could bill by the level of reported occupant thermal comfort, for example, would eagerly undertake home insulation retrofits, upgrade aging heat pumps, aggressively manage thermostat levels, and perform other cost-saving efficiency measures that could improve profit margins at the household level. The IOU, for its part, would find itself in new markets with broad growth potential and flat-footed "incumbents" (in the well-examined sense that energy end-users do not optimize energy efficiency as expected). Critics of this approach, however, decry a potentially choice- and innovation-suppressing model paralleling the Bell phone monopoly, which issued every American household an identical Western Electric telephone for decades.[108]

The Smart Integrator:

The "smart integrator" archetype, on the other hand, represents a diametrically opposite approach: here, the role of the IOU grows to assume many of the grid- and dispatch-management roles played today in California by the CAISO and expands on that to include new, information-rich management of both diverse distributed power infrastructure and precise customer loads, but it steps away from primacy in electricity supply itself.

> A smart integrator IOU, for example, might use dynamic pricing and real-time, automated device-level load control alongside microgrid-specific dispatch of electricity storage or generation assets to optimize the efficiency of electricity service supply and demand. Centralized, smart integration at this level could dramatically improve overall electricity system costs but would require real investments in new, enabling infrastructure, operational processes, and management software that could form a significant IOU profit base. Some have taken this approach even farther, noting that with technological advancements in information structuring, communication protocols, and decision algorithms alongside a common-pool resource approach to market structures, much of the smart integrator's proposed roles could in fact become distributed themselves through a decentralized, yet self-coordinated, network.[109]
>
> *From Peter-Fox Penner, Smart Power, 2010*

Ultimately, the technological advances that have already put renewable and distributed power systems within reach of California and other states must be matched by advances in regulation and business. And it is likely that the best way to close that gap is not just the issuance of further dockets and policy goals—regulation-as-usual. What is needed is a major reassessment—from a blank slate—among those that best know the system, its opportunities, and its risks. Renewable and distributed power grid transformation efforts frame a natural window of opportunity, much in the same way that the rise of affordable natural gas combined-cycle power plants late last century set the stage for wholesale power deregulation efforts nationwide. With the technology evolving, and market transformation opportunities looming, it is up to the will of state-level political leaders and the public in California and elsewhere around the country to define what the second hundred years of electric power will look like for the United States.

APPENDICES

Appendix I: California's Renewable and Distributed Power Programs

California's Seven RPS-Eligible Programs[110]

The following is a short summary of California's seven RPS programs:

a) *RPS power purchase agreements (PPAs)* (CPUC, CEC, all utilities)
California PPA procurement is a highly competitive process, using a statutorily specified "least cost-best fit" criteria with intense competition for lower cost. IOUs can also sign bilateral PPAs, but IOUs have generally limited such PPAs. Many of the PPAs were signed when renewable costs were higher and the market less competitive. Thus, a major factor facing utilities and the CPUC is the treatment of such contracts. Voiding contracts could result in lower prices from renegotiated or new contracts. However, such an approach would significantly shake confidence in the stability of the California market and be open to legal challenge. Another looming issue is the potential expiration of federal tax credits.[111]

b) *Tradable Renewable Energy Credits (TRECs)* (CPUC, CEC, all utilities)
RECs are certificates of proof that one megawatt-hour (MWh) of electricity was generated by an eligible, renewable energy resource. They can be procured either in- or out-of-state. The California Legislature has set strict limits on the amount of TRECs that IOUs can rely upon for the RPS in order to promote in-state jobs and the full utilization of major, new, in-state transmission lines being funded by ratepayers to carry renewables.[112]

c) *Qualifying Facilities ("QFs") contracts* (CPUC, IOUs)
IOU renewable electricity procurement mechanisms include purchases from "qualifying facilities" (QFs), which employ combined heat and power generation technology (CHP), as authorized under the 1978 *Public Utility Regulatory Policies Act* (PURPA). QFs predate the state's RPS mandates, and the CPUC has established rules that allow QF facilities producing renewable energy that is sold to IOUs to qualify as RPS-eligible power.

d) *Utility-Owned Generation (UOG)* (CPUC, CEC, utilities)
State law encourages UOG procurement of renewables up to 8.25% of all retail sales—i.e., up to 25% of all renewable energy sales. However, no major UOG renewables have been procured outside of the SPVP.[113]

e) *Solar Photovoltaic Program (SPVP)* (CPUC, IOUs)
The SPVP, established by the CPUC in 2009, is a five-year program to develop 1,100 MW in the three IOU service areas. The goal is to facilitate new solar PV

near load, where there is surplus capacity on the existing distribution system. Project size ranges from 1–2 MW (SCE), 1–5 MW (SDG&E), and 1–20 MW (PG&E). The 1100 MW is split roughly 50/50 between utility-owned generation (UOG) and third-party competitive solicitation PPAs.[114]

f) *Renewable Auction Mechanism (RAM)* (CPUC, IOUs)
The RAM, established by the CPUC in 2010, targets developing 1,000 MW[115] by holding four auctions over two years, using streamlined, market-based procurement mechanisms for renewable distributed generation.[116]

g) *Feed-In Tariffs (FIT)* (CPUC, all utilities)
The Legislature requires all California utilities (IOUs and POUs) to implement FIT programs for generators up to 3 MW, with a statewide cap of 750 MW. The IOU portion is 475 MW. The CPUC oversees the IOU efforts and recently adopted a new pricing mechanism (based on the RAM program price) that adjusts the standard price every two months.[117]

California's Four RPS-Ineligible Renewable Programs
California has four other programs that support renewable power generation but do not qualify as RPS-eligible power.[118] These programs subsidize significant development of customer-side, on-site, renewable electricity generation.[119]

a) *California Solar Initiative (CSI)* (CPUC, end-use customers)
This ten-year program, begun in 2006, is designed to bring on line 3,000 MW of solar PV. It is open to both residential and non-residential IOU customers, offering declining incentives over time. Projects must be sized so that the amount of electricity produced by the project is used primarily to offset part or all of the customer's electrical needs at the project site.

b) *Net Energy Metering (NEM)* (CPUC, IOUs, end-use customers)
The CPUC's net energy metering (NEM) program, existing since 1995, requires IOUs to let customers directly offset their utility electricity consumption with surplus electricity generated on site from systems smaller than 1 MW in size.[120] Electricity purchased by IOUs under NEM that does not exceed total yearly on-site load is not RPS-eligible but does reduce total electricity system demand from utility-scale generation. The CPUC estimated that 40,000 accounts had enrolled in NEM as of December 2008. This amount grew to 100,000 accounts by May 2012. In May 2012, the CPUC interpreted the legislative cap for NEM to increase the amount of allowed statewide capacity from 2,400 MW to 5,200 MW. NEM is available for residential and non-residential projects of 1 MW or less on a first come, first served basis. Virtual net metering (VNM) is allowed for multi-tenant properties, and meter aggregation is allowed for local governments if all participating accounts receive a time-of-use rate.

c) *Self-Generation Incentive Program (SGIP)* (CPUC, end-use customers)
Initiated by the CPUC in 2001 under direction of AB 970, SGIP provides financial incentives for the installation of new, non-solar, low-carbon distributed generation technologies: wind turbines, waste-heat–to–power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells, and advanced energy storage systems. Solar PV technologies were removed from SGIP in 2007 with the creation of the CSI. In 2009, SB 412 extended SGIP through 2015 and authorized the CPUC to expand eligibility of technologies for the SGIP based on greenhouse gas emissions reductions.

d) *New Solar Homes Partnership Program (NSHP)* (CEC, end-use customers)
The NSHP, authorized by the Legislature in 2006, provides financial incentives and other support through the CEC for solar systems on new residential buildings in IOU service areas. The NSHP program is offered for both conventional or market-rate housing and for affordable housing projects. The NSHP has a goal of 400 MW by 2016.

Appendix II: California's Renewable and Distributed Power Program Costs

RPS-Eligible Program Costs

As discussed in **Appendix I**, there are seven California programs for RPS-eligible renewables. The cost of the RPS energy being procured under these programs varies widely:

a) *RPS Power Purchase Agreements (PPAs) (RFOs and bilateral contracts)*
The CPUC's DRA estimates that IOUs will spend an average of $1.22 billion annually through 2020 on renewable electricity procured through the RFO process at an average rate of about $105.85 per MWh, with a total of $20.8 billion over 2003–2020.[121] Bilateral, negotiated PPAs for renewable power are expected to total a further $780 million annually over that period, at an average, wholesale rate equivalent of $99.32 per MWh, for a total of $13.3 billion.[122] It is difficult to say precisely how much California IOUs are currently spending on long-term renewable procurement because project bids are currently kept confidential for a period of three years[123] to deter strategic bidding behavior. The "above-market-funds" (AMF) account, once used in California to manage renewable electricity costs, was exhausted in 2009. Total RPS compliance costs are currently uncapped. An ongoing CPUC rulemaking is explicitly addressing RPS cost containment for the first time under the 33% RPS program.[124] Moreover, in terms of impact of RPS procurement on retail electricity rates, cost pass-though will not occur until RPS-eligible projects actually begin delivering electricity. Because the bulk of RPS projects are still in contracting or development phase, most consumer-rate impacts from these investments are not yet being felt.[125]

b) *Tradable Renewable Energy Credits (TRECs)*
IOUs purchased 5 TWhs of TRECS in 2010, and PG&E and SCE forecast the procurement of 27.57 TWhs of TRECS for the 2010–2013 period. These amounts represent a maximum annual average spending of about $350 million over the 2010–2013 period, with a total four-year spending of about $1.4 billion.[126]

c) *Qualifying Facilities (QFs) contracts*
Currently, California QFs represent 3.72 GW of renewable power capacity. The IOUs are expected to spend an average of $1.22 billion annually on such resources at approximately $80 per MWh through 2020, for a total of $20.7 billion over 2003–2020.[127]

d) *Utility-Owned Generation (UOG)*
To date, no major utility-owned renewables have been procured outside of the SPVP, and thus there are no associated costs with renewable UOG.[128]

e) *Solar Photovoltaic Program (SPVP)*
PG&E has received CPUC approval to develop 250 MW of utility-owned PV generation over the five years 2010–2014, at an estimated capital cost of $1.45 billion, and to sign competitive third-party, small-scale PV PPAs for an additional 250 MW, at a maximum rate of $246/MWh. The CPUC approved SCE for 250 MW of utility-owned PV at a cost of $963 million, with an additional 250 MW in third-party PPAs. SDG&E was approved for 26 MW of utility-owned PV at a cost of about $103 million and an additional 74 MW in third-party PPAs.[129] Actual SPVP project development appears to have fallen behind approved quotas: DRA reports that as of early 2012, SCE and PG&E have each signed third-party PPAs for 50MW, and SCE was developing 43MW of utility-owned generation.[130]

f) *Renewable Auction Mechanism (RAM)*
The RAM has to date seen an average, accepted high bid of $89.23 per MWh. PG&E has estimated total future expenditures on RAM contracts of about $870 million from 2014 to 2020 for its customers, reaching about $144 million annually by 2016.[131]

g) *Feed-in Tariffs (FIT)*
This year, the CPUC changed the FIT from a "value-based" tariff, pegged to wholesale rates,[132] to a new, dynamic pricing scheme based on the level established at contemporaneous RAM auctions.[133] PG&E has estimated that its total future expenditure on FIT contracts will be about $223 million from 2015 to 2020 for its customers, reaching about $41 million annually by 2016.
In addition to these seven current programs, the CEC administered another, now-closed RPS program, the ERFP. About $332 million in payments were made from 1998 to 2011.[134]

RPS-Ineligible, Renewable Program Costs

Below is a summary of publicly available information on the four RPS-ineligible, renewable programs. As noted in **Appendix I**, the Legislature has ended a fifth non-RPS–eligible, renewable program, the Emerging Renewables Program (ERP). The cost of that program from 1998 to 2011 was $409 million.[135]

a) *California Solar Initiative (CSI)*

Under the CSI, IOUs are authorized to administer $2.37 billion over the 2007–2016 program period. As of June 2012, IOUs had distributed or authorized $1.62 billion[136] in upfront and performance-based incentives, and the program's funding cap was recently raised by $200 million amid high customer demand.[137]

b) *Net Energy Metering (NEM)*

The IOUs buy surplus PV generation from NEM-registered customers at the retail electricity rate, which significantly exceeds standard wholesale PV electricity rates and the value to the IOU of that energy. The CPUC describes NEM funding flows by saying that "all ratepayers pay for NEM program costs in the form of billing credits, administrative costs, and interconnection costs, and all ratepayers receive some benefit from the NEM program in the form of avoided capacity and avoided RPS purchases."[138] A 2010 CPUC cost-effectiveness study conservatively put the cost of NEM at $20 million per year in 2008 and increasing over time.[139] The study goes on to posit that "if the total installed capacity of NEM solar generation reached 2,550 MW of solar capacity by 2017, the total cost of the program would be $137 million per year".[140] IOUs claim that the subsidy is much higher.[141] Though the average cost of retail electricity offset by NEM is about 14.4 cents per kWh, PG&E has argued that the NEM subsidy is, in fact, closer to 25 cents per kWh because NEM customers are generally offsetting marginal electricity use that would otherwise be priced at higher-tiered rates for heavy-consumption end-users. Amidst criticism of the size and costs of NEM by IOUs, the CPUC has begun a cost-effectiveness and cost-shifting study to inform revision of the NEM structure by January 2015.[142]

c) *Self-Generation Incentive Program (SGIP)*

SGIP has a program budget of $83 million per year for the period 2010–2014.[143] Before that, it paid out $623 million in upfront and performance-based incentives from 2001 to 2009 while collecting a further $98 million in reserve for active projects.[144]

d) *New Solar Homes Partnership (NSHP)*

The CPUC has budgeted $400 million of CSI funding from 2007 to 2016 for the NSHP.[145]

Appendix III: Once-Through Cooling and Nuclear Station Outage Costs

Once-Through Cooling (OTC)

The California State Water Resources Control Board's *Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling,* which stems from federal Clean Water Act regulations, requires that California power plant marine cooling water intake structures employ closed-cycle wet cooling to protect aquatic environments. OTC phase-out requirements will be implemented from 2010 to 2024, and the 19 affected plants in California represent about 30% of total in-state power generation installed capacity. Related costs are potentially very large, depending on how various plants come into compliance (plant retrofit, re-powering, replacement, retirement, etc.). For example, while many targeted plants that employ OTC are older, relatively inefficient natural gas facilities in congested load areas that might be retired or repowered, two operating nuclear plants are affected as well.[146] Total cost estimates for the OTC phase-out implementation vary widely. A 2008 study[147] estimated that retiring all 21GW of OTC plants would cost from $3 billion to $11 billion.[148]

San Onofre Nuclear Generating Station (SONGS)

The two nuclear generating units of SONGS, jointly owned by SCE and SDG&E, have been offline since January 2012, following discovery of unexpected component wear after generator replacement. Timelines for restarting the units are unclear, with Unit 3 in particular need of extensive repairs. As of August 2012, SCE had spent $117 million in replacement power (running over $20 million per month) and $48 million on inspection and repair costs. SCE estimates incremental costs for restarting Unit 2 at $25 million. SCE's annual revenue requirement for SONGS is approximately $650 million. Thus, the unresolved future of SONGS poses significant risk to the utilities, customers, and shareholders not only in terms of reliability but also utility costs and rate impacts.

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The authors of this report are solely responsible for its content.

Notes

1 CA Assembly Bill (AB) 32.

2 A Zero Net Energy (ZNE) building has annual zero net energy consumption and zero carbon emissions. California's ZNE goals are described in the California Long Term Energy Efficiency Strategic Plan. The goals include: 1) all new residential construction in California be zero net energy by 2020, and 2) all new commercial construction in California be zero net energy by 2030. *California Long Term Energy Efficiency Strategic Plan*, CPUC, September 2008. http://www.cpuc.ca.gov/NR/rdonlyres/D4321448-208C-48F9-9F62-1BBB14A8D717/0/EEStrategicPlan.pdf.

3 CA Senate Bill (SB) 2 (1X).

4 CEC, Draft Lead Commissioner's Report: 2012 Integrated Energy Policy Report Update ("CEC Draft IEPR Update"), CEC-100-2012-001-LCD, October 2012, pp. 1–2.

5 Data is for 2011 and is derived from the California Energy Commission *Energy Almanac,* online, 2012. http://energyalmanac.ca.gov/electricity/total_system_power.html

6 Table by authors; data for 2010; CEC Energy Consumption Data Management System, online, 2012.

7 CA Public Utilities Code, Secs. 394 and 331.

8 DRA represents California utility customers with the aim of minimizing IOU customer rates consistent with reliable and safe service levels. Public Utilities Code Sec. 309.5.

9 DRA, *The Renewable Jungle—A Guide to California's Renewable Policies and Programs,* January 2012, hereinafter cited as DRA Renewable Jungle 2012.

10 This number was originally 13 but is now 11 since the CEC has closed the Existing Renewable Facilities Program (ERFP) and the Emerging Renewables Program (ERP).

11 CPUC, *Electric and Gas Utility Cost Report (Public Utilities Code Section 747 Report to the Governor and Legislature),* April 2012, p. 19.

12 CEC, draft 2012 IEPR Update, October 2012, p. 2.

13 *Id.*

14 Edison International, Business Update, November 9, 2012, slide 24. http://edison.com/files/3Q12_BusinessUpdate.pdf.

15 Table by authors compiled from IOU filings to CPUC and CPUC Q42011/Q42012 RPS implementation reports.

16 DRA Renewable Jungle 2012, p. 14.

17 CEC, draft 2012 IEPR Update, October 2012, p. 2.

18 Figure from DRA Renewable Jungle 2012, p. 16; RPS programs are defined by black box outline.

19 DRA Renewable Jungle 2012, p. 17.

20 Table by authors, adapted from DRA Renewable Jungle 2012, p. 18.

21 Renewable resources integration (3 subparts), the 2012–2013 Transmission planning process, the Deliverability for distributed generation, Transmission planning and generator interconnection integration, and Flexible capacity procurement. http://www.caiso.com/informed/Pages/StakeholderProcesses/Default.aspx. The CAISO is also involved in joint efforts with the other California energy agencies, such as California's Clean Energy Future and the Renewable Energy Transmission Initiative (RETI).

22 According to the CPUC's latest report to the California Legislature: (1) System average rate increases of California's electric IOUs have roughly tracked inflation between 2003 and 2011; (2) Electric generation and energy procurement are a large component of electric rates, accounting for approximately 47% of utilities' electric rates; (3) Demand-side management has been a cost-effective method to meet new demand; (4) RPS-eligible energy remains a small but growing component of revenue requirements. [CPUC, 2011 Gas & Electric Utility Cost Report, April 2012, pp. 6–7].

23 CPUC Commissioner Ferron's Presentation made to the Power Association of Northern California (May 10, 2012). http://www.cpuc.ca.gov/NR/rdonlyres/DD7898B2-889E-4A69-A363-0CA893DA8ED2/0/FerronPANC120510FINAL.pdf.

24 According to the EIA's State Energy Data System, California retail electricity rates in 2010 were ranked eleventh in the United States and were about 32% higher than the US average.

25 EIA also reports that because of these factors, California's total electricity retail expenditures were only about 8.8% of the US total despite having 12.2% of the US population.

26 Edison International, Business Update, November 9, 2012, slide 28. http://edison.com/files/3Q12_BusinessUpdate.pdf.

27 Figure by authors from CEC CA Energy Almanac 2012 data.

28 In real terms. CPUC Commissioner Ferron web page [http://www.cpuc.ca.gov/PUC/aboutus/Commissioners/Ferron/speeches.html]. The estimate for fossil costs does not include any additional costs due to the SONGS outage since the CPUC has not determined what ratepayer responsibilities are for these costs. Personal communication with M. Colvin, CPUC, October 19, 2012.

29 CEC Commission Final Report, "California energy demand: 2012–2022 final forecast," June 2012. CEC-200-2012-001-CMF-VI. Volume 1, p. 30.

30 CPUC "33% RPS Implementation Analysis Preliminary Results," June 2009, with technical analysis by Energy and Environmental Economics, Inc. and Aspen Environmental Group. http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf.

31 Baseline (non-RPS), average retail electricity rates were estimated to rise by 16.7% over the same 2008–2020 period statewide, in real terms. Table 5 (p22) of the report indicates 2008 "total statewide electricity expenditures"/ "average statewide electricity cost per kWh" of $36.8 billion/ $0.132/kWh, 2020 "all-gas" case (no new, renewable development from 2007–on) costs/rates of $49.2 billion/ $0.154/kWh, and 2020 "33% RPS reference" case costs/ rates of $54.2 billion/ $0.169/kWh (Y2008 dollars).

32 *Id.*, pp.1, 7. This 33% RPS Reference Case assumed significant amounts of new technologies such as central station solar thermal.

33 Y2008 dollars. Statewide investment requirements are from the 2009 report Table 13 at p. 53 and represent total investment levels of $95.3 billion in capital for new renewable generation, $12.3 billion for new transmission investment, and $6.9 billion for new conventional generation. These are total capital investment costs and do not necessarily represent net total costs to electricity consumers.

34 This sensitivity was modeled as solar PV prices falling from $5.83/nameplate Watt in 2009 to $3.08/Watt by 2020 (delivered costs of $306/MWh down to $168/MWh). See report p. 31.

35 Henry Hub, in Y2008 dollars through 2020. CPUC "33% RPS Implementation Analysis Preliminary Results," June 2009. p. 25.

36 For example, while no longer directly used to determine RPS procurement, prior California RPS methodology used a "Market Price Referent" (MPR) as a benchmark for RPS pricing. The MPR modeled the cost of building and operating a 500 MW combined-cycle natural gas power plant in California and was adjusted each year during the IOU RPS solicitation process to account for changes in 1–12 year delivery NYMEX natural gas futures and labor/building material costs. The 2011 all-in 10-year contract MPR for 2015 delivery was down 24% (in nominal terms) from the 2008 MPR established just after Governor Schwarzenegger signed the 33% RPS executive order.

37 Joint IOU filing to CPUC in LTPP track one, July 1, 2011, with modeling by E3; assumes the August 2010 natural gas MPR of $4.95/MMBTU in 2011 and associated futures. Often such filings represent only the first step of a formal stakeholder process meant to arrive at the most realistic and reasonable assessment of future IOU revenue requirements and investment needs; the figures presented here do not reflect related stakeholder commentary. http://www.cpuc.ca.gov/NR/rdonlyres/070BF372-82B0-4E2B-90B6-0B7BF85D20E6/0/JointIOULTPP_TrackI_JointIOUTestimony.pdf

38 Joint IOU filing. p. A-66.

39 In real terms; this estimate is equivalent to a total 18.6% real growth in rates from 2011–2020.

40 Direct nominal RPS costs (not including EE or DR but accounting for incremental transmission, distribution, and integration costs) compared to an "all-gas" 12.5% renewable case. See "Revised joint proposal and supplemental information of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company on the appropriate use of allowance auction revenues," January 6, 2012. R.11-03-012. p. C-1.

41 Annual 2010 total revenue requirement components for 2020 in the trajectory case were reported as follows (Y2010$): distribution $10.3 billion (27.6%); transmission $3.3 billion (9.0%); demand-side programs $2.4 billion (6.3%); generation fixed costs $8.9 billion (23.8%); RPS resource costs $7.7 billion (20.8%); variable costs of energy $5.4 billion (14.5%); net ancillary services purchases $0.3 billion (0.8%); and net GHG allowance costs to

ratepayers of negative $1.0 billion [from free allocation of AB32 GHG emission allowances to IOUs]. These estimates total $37.3 billion. p. A-68.

42 CEC Draft IEPR Update, p. 58.

43 CEC Draft IEPR Update.

44 Caltech Resnick Institute "Grid 2020 Towards a Policy of Renewable and Distributed Energy Resources" report, p. 29. http://resnick.caltech.edu/learn/docs/GRID_2020_Resnick%20Report.pdf. Personal communication with P. De Martini, Newport Consulting Group.

45 This rough estimate assumes: base case total load levels of 195,807 GWh in 2013 rising to 197,165 GWh in 2019 with marginal 33% RPS attainment costs of $1.46 billion in 2013 and $3.51 billion in 2019 [See Box 2 and note above; marginal RPS costs exceeding a 12.5% renewable mix "all-gas" case; load levels from Joint IOU filing to CPUC in LTPP track one, July 1, 2011, pA-42] for a typical household consumption of about 500 kWh per month. This estimate indicates a typical household's share of total utility costs and may not directly correspond to expected rate increases. For example, this cost estimate does not explicitly include the typical rate discount applied to residential electricity users compared to commercial or industrial accounts, which might reduce residential users' share of these proportional costs. It also does not explicitly include the costs of programs for renewable and distributed power, such as CSI, that are not RPS eligible, which might otherwise increase expected proportional utility costs. The estimate can, however, be thought of as at least order-of-magnitude accurate and reasonably relatively accurate over time (i.e., the 2019 marginal household cost share will be about twice the 2013 marginal cost).

46 Table by authors with data from DRA Renewable Jungle 2012 and other sources; see Appendix II for details.

47 Public Utilities Code section 399.15(c).

48 *Id.*, section 399.15(f).

49 See, e.g., CEC Draft IEPR Update, p. 6.

50 See, AB1X (2001) and SB 695 (2009).

51 Figure by authors in the style of Ferron 2012 with data from PG&E Corrected Testimony Rate Design Window 2012 pp. 1–10.

52 This tiered rate, also known as "increasing-block pricing" (IBP), was introduced to encourage electricity conservation among end users by raising, step-wise, the cost of marginal monthly electricity consumption. Prior to the electricity crisis, California residential IOU consumers had only two rate tiers; CPUC expanded this to five tiers following the crises-era rate freezes but then reduced it to four functional tiers for most customers in Summer 2010.

53 As a corollary, the CARE electricity rate subsidy program for low-income customers is an additional cross-subsidy among customers, with a budget of $2.6 billion for 2009–2011 [D.08-11-031]. PG&E estimates that its average CARE rate (applied to about 30% of residential customers) in 2010/2011 was 46% lower in real terms than it was in 1991 due to these rates rising more slowly than other residential rates and the inflation rate [PG&E Quandrini in CPUC decision regarding residential rate design, May 26 2011, A.10-03-014]. SDG&E similarly reports that discounts to CARE customers, who constitute 23% of residential customers, result in a 10% average increase in non-CARE rates [SDG&E in 2012 CPUC SB 695 report].

54 Specifically, Tiers 1 and 2; CPUC Decision (D.11-05-047) regarding residential rate design, May 26, 2011, A.10-03-014. p. 7.

55 In its 2012 report to the CPUC on utility costs and rate pressures, PG&E reported that “absent meaningful tiered-rate reform, residential customers in the upper tiers [tiers 3 and 4] may be forced to shoulder the burden of an additional five to six cents per kilowatt hour rate just to pay for the increased renewable energy requirements.” This estimate does not account for expected baseline IOU cost growth. PG&E writing in CPUC 2012 SB 695. p. 54.

56 Average California residential rooftop PV system costs, as of January 2011, were $34,800 for an average size 4 kW system [Go Solar California Consumer Guide to CSI Incentives, 2008. http://www.gosolarcalifornia.org/solar_basics/pricing_financing.php].

57 The average residential panel installed today is 6–7 kW, which exceeds the non-coincident peak load of the average house.

58 Examples include renters, short-term residents, those with unfavorable dwelling geography, wiring, or roof configuration, and those faced with local permitting barriers.

59 ARB, Climate Change Scoping Plan, December 2008.

60 May 2003 Energy Action Plan. The 2003 EAP was updated in the October 2005 Energy Action Plan II and in 2008.

61 The Loading Order does not address distributed generation or CHP directly, but they are commonly assumed to be incorporated in the renewable energy framework.

62 These charges, including the competition transition charge (CTC), the DWR power charge, the DWR bond charge, and the energy recovery bonds stem from California’s deregulation efforts and the ensuing California electricity crisis and utility bankruptcies (the CTC also includes some payments for QF power purchases). The PG&E energy recovery bonds are set to expire in 2012, the DWR bond charge is set to expire in 2022, while the CTC is not currently set to expire. Revenue from these charges exceeded $3.1 billion for CA IOUs in 2011. See *Electric and Gas Utility Cost Report (Public Utilities Code Section 747 Report to the Governor and Legislature),* CPUC, April 2012, p. 36.

63 CEC Draft IEPR Update, p. 4, calls out the need for California to include the distribution system in its planning process, including making distribution planning more transparent.

64 See, e.g., Caltech Resnick Institute “Grid 2020 Towards a Policy of Renewable and Distributed Energy Resources” Report.

65 A commonly cited problem is that the CPUC is a constitutional entity and thus its powers cannot be circumscribed by the Legislature or the Governor. Nevertheless, other states (e.g., Texas and Massachusetts) with similar constitutionally based public utility commissions have designated a lead agency and identified the role of the state PUC within that leadership framework.

66 http://www.cacleanenergyfuture.org.

67 Clean Energy Future Overview, p. 1.

68 Almost every Governor has issued an energy reorganization plan and the Little Hoover Commission, whose mission is to investigate state government operations and recommends proposals to promote efficiency, economy, and improved service, has repeatedly called for reform. Indeed, the Little Hoover Commission is currently reviewing the state’s coordination of energy-related activities. [See the Little Hoover Commission’s website: www.lhc.ca.gov].

69 California Center for Sustainable Energy (CCSE) [http://energycenter.org/index.php/public-affairs/california-legislation]. The CEC’s Legislative Summaries of Energy-Related Legislation [http://www.energy.ca.gov].

70 - AB 1969, effective January 2007, added Public Utilities Code Section 399.20, first authorizing tariffs and standard contracts for the purchase of eligible renewable generation from only public water and wastewater facilities.

- In 2007, the Commission adopted D.07-07-027, implementing the program as set forth in AB 1969.
- Since 2007, the Legislature adopted several amendments to § 399.20, including SB 380, SB 32, and SB 2 1X.
- The most recent decision (D.12-05-035) in the current RPS Rulemaking, R.11-05-005 issued on May 31, 2012, addresses these amendments by, among other things, adopting a new pricing mechanism and increasing the maximum size of eligible facilities for the FIT program.
- And the majority of the issues related to the interconnection under the FIT Program are addressed in a separate Commission proceeding, R. 11-09-011, Order Instituting Rulemaking on the Commission's own motion to improve distribution level interconnection rules and regulations for certain classes of electric generators and electric storage resources.

71 CEC website. http://www.energy.ca.gov.

72 CPUC Dockets R.11-05-005 (RPS), R.12-03-014 (Long-Term Procurement), R.10-05-004 (Distributed Generation), R.11-09-011 (Distribution Interconnection), R.11-10-023 (Resource Adequacy), and A.12-01-008 (SDG&E Application for Authority to Implement Optional Pilot Program to Increase Customer Access to Solar Generated Electricity).

73 Such dockets include items such as single funding utility requests or general rate case funding applications.

74 The CAISO established a new corporate division at the end of October, the Market Quality and Renewable Integration Division, which will hopefully lead to a more streamlined process but how it will integrated with non-CAISO efforts is unclear.

75 The Database of State Incentives for Renewables and Efficiency (DSIRE), which tracks such programs across the entire U.S. with a staff of nine. http://www.dsireusa.org.

76 Governor Brown's Clean Energy Jobs Plan. http://www.jerrybrown.org/sites/default/files/6-15%20Clean_Energy%20Plan.pdf.

77 *California's Transition To Local Renewable Energy: 12,000 Megawatts By 2020,* Berkeley Law, University of California, June 7, 2012, p. II.

78 The CEC's draft IEPR Update with its Renewable Action Plan provides a useful first step and could be the basis for this framework approach, but only if there is a commitment by the other state entities to participle in the development and implementation of the resulting plans.

79 May 2012 CPUC Mission Statement.

80 Decoupling removes the incentives for utilities to oppose energy efficiency goals and programs, but it does not provide a positive return to shareholders—i.e., an incentive.

81 The CPUC capped shareholder rewards at about $150 million annually across the four IOUs.

82 CPUC Decision (D.) 07-09-043 "Interim opinion on phase 1 issues: shareholder risk/reward incentive mechanism for energy efficiency programs," September 20, 2007. R.06-04-010.

83 See, e.g., Resources for the Future, "Energy-Efficiency Program Evaluations—Opportunities for Learning and Inputs to Incentive Mechanisms," April 2010, RFF DP 10–16, p. 3.

84 Indeed, the CPUC is examining in its long-term procurement proceeding allowing demand-side resources to compete with supply-side resources (Rulemaking 12-03-014). Additionally, the CPUC issued Decision 12-01-015

on November 15, 2012, which would allow three non-IOUs to administer ratepayer-funded energy efficiency programs, in addition to continuing IOU administration. ("Decision Adopting 2013–2014 Energy Efficiency Programs and Budgets," November 8, 2012. Application 12-07-001).

85 The CEC administers the remaining 80%. CPUC D.12-05-037 "Phase 2 Establishing Purposes and Governance for Electric Program Investment Charge and Establishing Funding Collections for 2013—2020," May 24, 2012. R.11-10-003.

86 "Grid 2020: Towards a Policy of Renewable and Distributed Energy Resources," Resnick Institute Report, Resnick Sustainability Institute at Caltech, September 2012, p. 32.

87 *Id.*

88 The US National Science Foundation estimates 2007 non-federal R&D spending in the utility industry at 0.1% of net sales [NSF Science and Engineering Indicators 2010, appendix table 14-4].

89 From rough CEC estimates for California [CEC October 2003 "Feasibility of Implementing Dynamic Pricing in California," 400-03-020F]. A separate recent experiment in Washington DC, found that residential customers exposed to dynamic pricing during hot summer days reduced electricity demand by 15–20% [Wolak, Frank A. (2010) "An Experimental Comparison of Critical Peak and Hourly Pricing: The PowerCentsDC Program"]. Elsewhere, the New York ISO [NYISO October 2009 "Dynamic Pricing: Potential Wholesale Market Benefits in New York State"] estimated net social utility gains of $141 million to $403 million annually for the state if dynamic pricing were adopted.

90 See, for example, the often-cited case of reductions in US domestic airline ticket prices following deregulation of ticket pricing—despite a lack of significant technological change or industry windfall profits [Wolak, F.A. (2007) "Managing Demand-Side Economic and Political Constraints on Electricity Restructuring Processes"].

91 See, for example, 2012 SB 695 report to CPUC's discussion of concerns around implementing various dynamic pricing mechanisms (p. 31) and DRRP Proceeding A.10-08-005 and A.10-02-028's February 7, 2012, ALJ ruling (p. 6) citing PG&E's delay in implementing dynamic pricing options among its customers.

92 As noted above, third party-owned rooftop solar PV systems are gaining in popularity in California and represented 54% of CSI residential projects applications in 2011 (and rising) but just 23% of commercial project applications (and falling) [CPUC CSI Annual Assessment June 2012, p. 31].

93 See CPUC CSI Annual Assessment June 2012 as a proxy for recent overall California rooftop solar PV trends, p. 20.

94 Figure by authors from aggregate datasets: data prior to 2007 is from the CEC Energy Almanac [http://www.energy.ca.gov/renewables/emerging_renewables/GRID_CONNECTED_PV_12-31-07.XLS]; data after 2007 for POUs is from CEC SB1 annual reporting [http://www.energy.ca.gov/sb1/pou_reports/index.html]; CSI data is from GoSolar California [http://www.californiasolarstatistics.ca.gov]. Yearly data is for total state-wide installed capacity of customer-sited grid-connected PV systems as of Dec 31. "IOU territory—other" includes installations registered under the ERP, SGIP, and NSHP.

95 For an overview, see "Distributed Power in the United States: Prospects and Policies," The Hoover and Brookings Institutions, 2013.

96 ESP customers have generally been required to pay "exit fees" to IOUs before entering into direct access contracts, to compensate IOUs for their now stranded distribution infrastructure investments. CCA customers remain even more tightly integrated as IOUs continue to own and operate transmission and distribution assets in addition to providing billing services. CCA customers must pay an additional IOU-determined monthly fee to the legacy IOU for these services.

97 The recent CPUC net energy metering enrollment cap "clarification," which expands the limit on NEM, shows California's regulatory support for development of non-utility–owned distributed power. D.12-05-036 "Calculation of the Net Energy Metering Cap," May 24, 2012. R.10-05-004.

98 See, for example, RMI "Net energy metering, zero net energy and the distributed energy resource future," February 2012. p. 27.

99 DOE 2012 Electricity Advisory Committee, "Non-Wires Solutions" Whitepaper, October 2012.

100 See, "Net Energy Metering, Zero Net Energy and the Distributed Energy Resource Future," prepared by the Rocky Mountain Institute on behalf of PG&E, March 2012. Interestingly, the report's last page states the report was paid for by PG&E ratepayers.

101 There are a number of detailed interconnection rules for small systems that represent barriers to interconnection and uncertainty. For example, the Rule 21 interconnection screening process currently allows very little penetration of distributed generation on a distribution system. Looking down the road, experts believe that inverters that are allowed to adjust power factor to control voltage must be allowed to interconnect.

102 The CEC Draft IEPR Update states that agencies, including the CPUC, CARB, DRA, and CAISO are required by law to "carry out their energy-related duties and responsibilities based upon the information and analyses contained in [the IEPR]" and that "[t]his requirement ensures that consistent information is used among all parties to develop energy policies and decisions affecting the state." Draft IEPR update, p. 1. Yet the draft IEPR also calls out the use of inconsistent information use among agencies. And, more importantly, the use of information does not ensure coordinated or integrated decision making. Far stronger measures are needed than an attempt to rely upon similar information.

103 The CEC's draft IEPR Update can be a starting point, but significant expansion is needed in the area of distributed generation, going beyond expanded planning efforts. One key area is also reform of the utility business model and third-party access to utility distribution information.

104 The CEC's Renewable Action Plan includes improving the transparency of renewable generation costs, particularly for distribution planning, and developing a framework to prepare transparent estimates of system costs. Priority should be given to the implementation of this recommendation.

105 J. Williams, A. DeBenedictis, R. Ghanadan, A. Mahone, J. Moore, W. Morrow II, S. Price and M. Torn, "The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity," Science, Vol. 335, January 6, 2012.

106 Their modeling suggests that electric generation mixes dominated by renewable energy, nuclear, and carbon capture and storage (CCS) would raise the average cost of electricity generation by a factor of about two.

107 In some ways, the rise of distributed generation and other bi-directional paradigms is similar to the push two decades ago for IOUs to help improve demand-side energy efficiency among their customers: a potential revenue reducer but with clear social benefits that required a core regulatory and business model shift to accommodate, however imperfectly.

108 See Lester and Hart, 2011, *Unlocking Energy Innovation.*

109 See, for example, Lynne Kiesling, 2009, *Deregulation, Innovation, and Market Liberalization* for her New Institutional Economics approach to structuring US electricity markets in order to encourage entry and innovation.

110 The CEC has closed an eighth RPS program, the Existing Renewable Facilities Program (ERFP). The ERFP subsidized in-state, renewable electricity generation (solid fuel biomass, solar thermal electric, and wind power) that

was installed before 1996 to maintain a case-by-case facility "target price" if the wholesale market price fell below that threshold.

111 The Production Tax Credit and the Investment Tax Credit (26 U.S.C. Sec. 48, Internal Revenue Code Sec. 45) provide significant financial support for renewable development. The PTC is set to expire the end of 2012. A large number of renewable projects in California and throughout the United States have obtained financing or assumed financing based on federal tax credits. Without the PTC, there will be significant pressure to raise PPA prices, which in term will likely face strong opposition.

112 SB 2 (1X) (2011) further modifies TREC usage and limits. With the legislation, the term 'TREC' is no longer in use. DRA Renewable Jungle 2012, p. 30.

113 DRA Renewable Jungle 2012, p. 42.

114 In February 2012, the CPUC adopted D.12-02-002 and D.12-02-035, modifying SDG&E's and SCE's PV programs, respectively, to shift program capacity from their PV programs to RAM in order to minimize ratepayer costs and lower the administrative burden to implement these procurement programs concurrently.

115 The CPUC expanded the program this year to 1,299 MW. D.12-02-002 and D.12-02-035.

116 The November 2011 first RAM auction was a learning process. PG&E, for example, aimed to accept bids for 105 MW of capacity split evenly over the three project categories (baseload, peaking, intermittent), but could not fill its quota for renewable baseload projects and as-available, off-peak intermittent projects (geothermal, landfill gas, biomass, small wind, and small hydro) while peaking projects (mostly solar PV) were far oversubscribed. PG&E requested CPUC approval for just 63 MW of projects.

117 CPUC D.12-05-035, May 24, 2012. R.11-05-005.

118 In 2012, the Legislature ended a fifth program, the Emerging Renewables Program (ERP) begun in 2007 (SB 1018). The ERP, administered by the CEC, provided rebates and production incentives to end-use customers using renewable energy technologies, specifically small wind systems and fuel cells, for on-site generation.

119 POU customers may be eligible for other locally administered on-site generation subsidy programs but are generally not eligible for these statewide initiatives.

120 About 99% of NEM-registered customers utilize solar PV. E3 NEM Cost Effectiveness Evaluation prepared for CPUC January 2010, p. 3.

121 DRA Renewable Jungle 2012, p. 20. This and other DRA estimates for future IOU spending on renewable procurement are aggregated from non-public filings by IOUs to the CPUC. Though IOUs individually and jointly report their own estimates of "incremental costs" and rate impacts from RPS-related procurement through 2020, their estimates are generally redacted in the public versions of CPUC filings. For example, see PG&E RPS Procurement Plan (Draft Version) May 23, 2012 (public version), one of 755 documents filed under the CPUC's current R.11-05-005 RPS proceeding.

122 DRA Renewable Jungle 2012, p. 21.

123 DRA Annual Report 2011, January 2012, p. 37.

124 As stated on the CPUC's website: The CPUC will be implementing a new cost-containment mechanism as mandated by the passage of Senate Bill No. 2 (SB2) in 2011. SB2 requires that the CPUC establish a limitation for each IOU on the procurement expenditures of all eligible renewable energy resources used to comply with the RPS. SB2 mandates that the CPUC rely on (1) the most recent renewable energy procurement plan, (2) procurement expenditures that approximate the expected cost of building, owning, and operating eligible renewable energy resources, and (3) the potential that some planned resource additions may be delayed or

cancelled. The CPUC is currently in the process of developing a cost-containment mechanism. (CPUC Docket 11-05-005.) Currently, there is no cost-limitation requirement for RPS-eligible, renewable resources delivering energy into the State of California.

125 For example, see PG&E RPS Procurement Plan (Draft Version) May 23 2012, public version (p. 81): "The costs of the RPS program have only begun to appear in customers' rates . . . [a report table indicates historical] annual rate impact within the range of 0.7 ¢/kWh and 1.4 ¢/kWh from 2003 to 2011, meaning the average rate impact from RPS-eligible procurement has nearly doubled in approximately eight years. However, this growth rate accelerates, which is clearly shown in [redacted table]."

126 SDG&E did not disclose TREC purchase forecasts. The estimate assumed that the expected volume of TREC purchases would occur at the $50/MWh TREC price cap (the maximum price at which TREC's are allowed to trade). DRA Renewable Jungle 2012, p. 21.

127 Data as of January 2011, estimate from DRA Renewable Jungle 2012, p. 20.

128 DRA Renewable Jungle 2012, p. 42.

129 In February 2012, the CPUC adopted D.12-02-002 and D.12-02-035 modifying SDG&E's and SCE's PV programs, respectively, to shift program capacity from their PV programs to RAM in order to minimize ratepayer costs and lower the administrative burden to implement these procurement programs concurrently.

130 DRA Renewable Jungle 2012, p. 39. All rates pre-time-of-day adjusted in Y2009$. IOU cost estimates include a 10% contingency factor. For PG&E see: A. 09-02-019 CPUC Decision 10-04-052 (April 22, 2010). For SCE see: A. 08-03-015 CPUC Decision 09-06-049 (June 18, 2009). For SDG&E see: A. 08-07-017 CPUC Decision 10-09-016 (September 2, 2010).

131 PG&E RPS Procurement Plan (Draft Version) May 23, 2012, public version. p. 84.

132 The pricing is equivalent to a natural gas combined cycle power plant, in contrast to the more generous cost-based FIT subsidized pricing schemes common in Europe.

133 Bid categories include baseload, peaking as-available, and non-peaking as-available.

134 CEC 2011 Renewable Energy Program 2011 Annual Report to the Legislature. CEC-300-2011-007-CMF. p. 12.

135 CEC 2011 Renewable Energy Program 2011 Annual Report to the Legislature. CEC-300-2011-007-CMF. p. 12.

136 PG&E, $783.8 million; SCE, $662.6 million; CCSE/ SDG&E, $170.9 million.

137 SB 585, September 2011.

138 CPUC SB 695 report to the legislature, May 2012, p. 34.

139 About $0.5 million per year is paid in net surplus compensation.

140 In 2008 dollars, CPUC Energy Division and E3 "Introduction to the Net Energy Metering Cost Effectiveness Evaluation," March 2010.

141 See discussion in cost allocation section for IOU estimates of NEM cost shifts.

142 CPUC Decision regarding calculation of the net energy metering cap. D.12-05-036, May 24, 2012. R.10-05-004.

143 Authorized from 2012 to 2014 by AB 1150 and 2010 to 2011 by SB 412.

144 DRA Renewable Jungle 2012, p. 49.

145 The CEC now expects, however, that this program quota will not be filled due to the slow new housing market and the high customer cost of meeting required efficiency levels. CEC “Renewable Power in California: Status and Issues: Lead Commissioner Report,” December 2011. CEC-150-2011-002-LCF-REV1.

146 Closed-loop cooling is not currently employed on any operating commercial nuclear power plant in the United States, so compliance costs and safety implications are uncertain. PG&E, for example, estimates the potential cost of retrofitting Diablo Canyon nuclear plant alone at $4.5 billion. [PG&E engineering study submitted to SWRCB, cited in 2011 CPUC SB 695 Report].

147 Electric Grid Reliability Impacts From Once-through Cooling in California, April 2008, prepared for the SWRCB.

148 This estimate assumed total plant retirement by 2015 (including nuclear plants, which is unlikely to occur), building 4 GW of replacement generation, and adding the requisite transmission to ensure electric system reliability.

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