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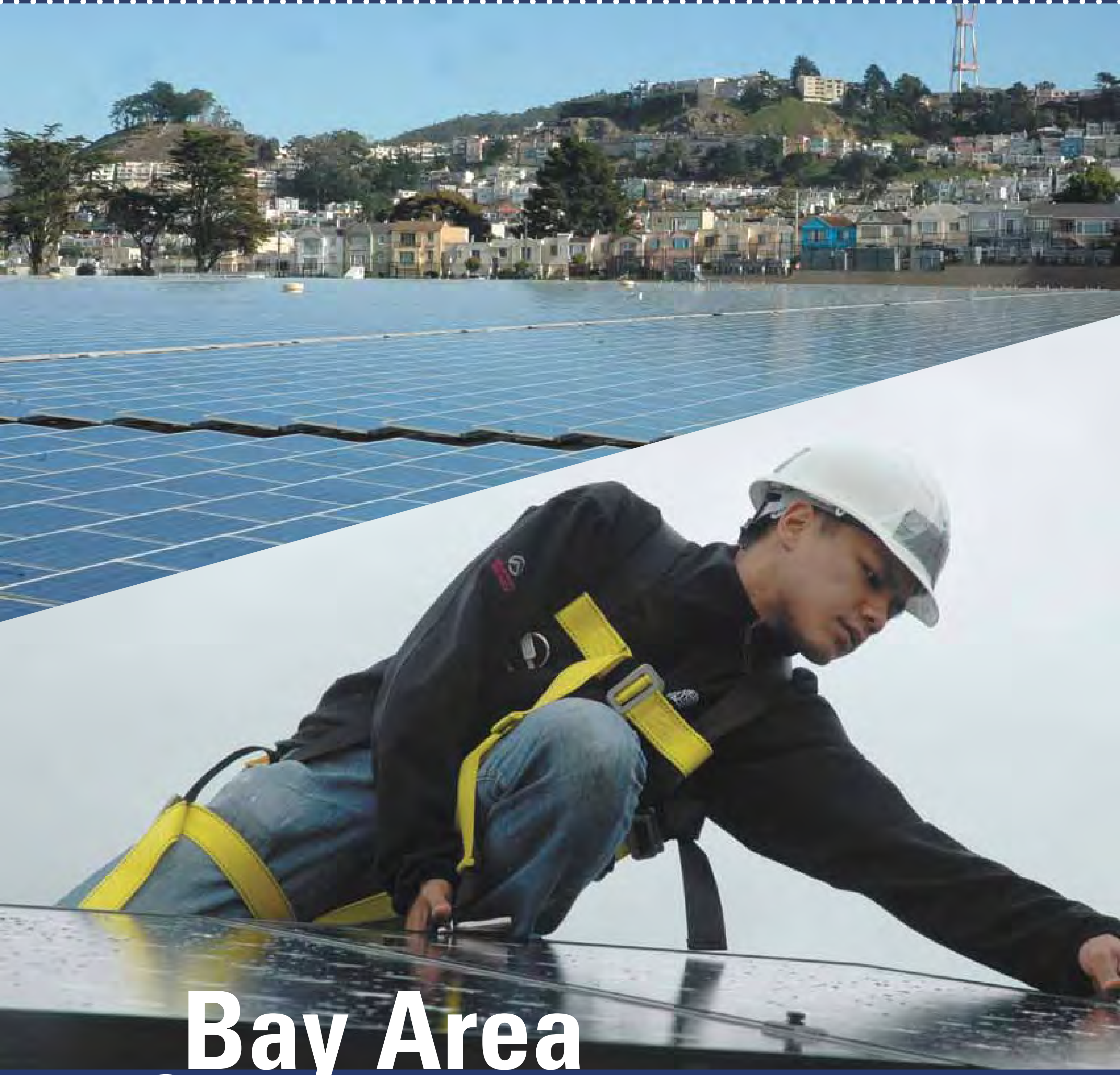

Bay Area Smart Energy 2020

By Bill Powers, P.E.
Powers Engineering

March, 2012

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Bay Area Smart Energy 2020

By Bill Powers, P.E.
Powers Engineering,
San Diego, California
March, 2012
Executive editor:
Rory Cox
Dedicated to the memory of Charles McGlashan

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Forward

THE WINDOW OF OPPORTUNITY TO BUILD the energy future of California is wide open. In 2011, Governor Jerry Brown called for a 33 percent renewable portfolio standard by 2020, AND for over half of that generation to come from locally generated, "distributed" power sources. As this is an unprecedented goal in the US, the Governor is seeking advice. And that is why *Bay Area Smart Energy 2020* is needed now.

Bay Area Smart Energy 2020 is a roadmap to rapid, cost-effective conversion to clean energy that relies on local resources. Our region is the right place to build the grid of the future. The San Francisco Bay Area is one of the world's leading centers of clean energy innovation and environmental awareness. The region has a long tradition of environmental leadership dating back to John Muir, and the Bay Area is host to technology leaders, progressive venture capitalists, effective government, environmentally-oriented labor leadership, and hundreds of leading environmental and social justice organizations.

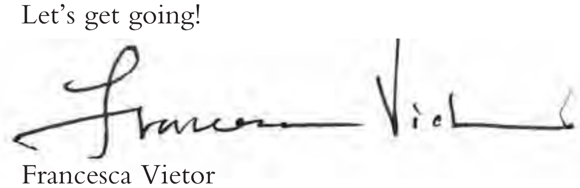
Silicon Valley is a lightning rod for clean energy innovation, hosting countless companies that are developing cutting edge technologies in solar, wind, and energy efficiency, along with the software and integration technology to make it all work. Many of these successful and promising companies were jumpstarted with billions of dollars from local venture capitalists.

Regional academic institutions like UC Berkeley, Lawrence Berkeley National Lab and Stanford are leading the way in clean energy research, while our elected leaders regularly support laws and programs to incentivize a cleaner, greener environment. The concept of "green collar jobs" has caught fire in the Bay Area, thanks to the vision of groups like the Oakland-based Ella Baker Center and local leaders like Van Jones. Progressive labor leaders have strongly supported California's landmark climate change laws, understanding that clean energy is the growth industry of the 21st century.

Despite these promising Bay Area conditions, however, less than 20 percent of our region's electric power today comes from truly clean sources. Amazingly, clean energy is too often under attack, with many politicians across the US working to undermine clean energy incentive programs, while offering no solutions to solve climate change or put people back to work.

If we build it, we will win. As this report demonstrates so well, the tools and technology already exist and are becoming more efficient, sophisticated and cost-effective. By developing local, clean energy projects and production, we will put people to work, reinvigorate our regional economy, and build a truly healthy and sustainable energy future.

Let's get going!



Francesca Vietor

Environment Program Officer, San Francisco Foundation and Commissioner, San Francisco Public Utilities Commission

Table of Contents

List of Tables

List of Figures

Appendices

Acronyms

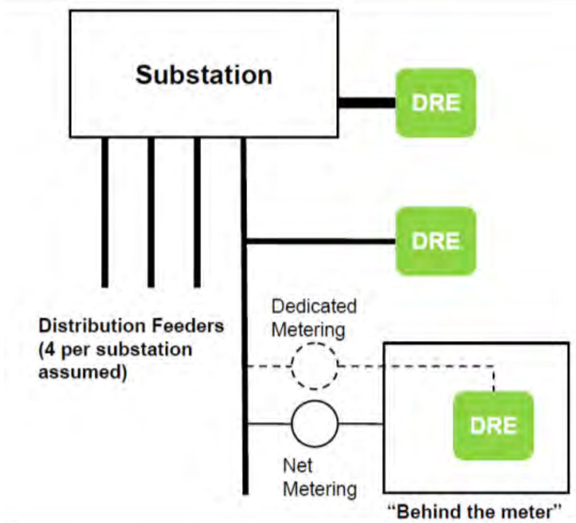
ACEEE	American Council for an Energy-Efficient Economy
AMP	Alameda Municipal Power
ARRA	American Recovery and Reinvestment Act
BASE	Bay Area Smart Energy
BART	Bay Area Rapid Transit
BLM	Bureau of Land Management
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCA	Community Choice Aggregation
CEC	California Energy Commission
CES	Community Energy Storage
CHP	Combined heat and power
CO2	Carbon dioxide
CPAU	City of Palo Alto Utilities
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
CVEUP	Chula Vista Energy Upgrade Project
DG	distributed generation
DOE	Department of Energy
DRA	Division of Ratepayers Advocates
DR	demand response
DWR	Department of Water Resources
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FHFA	Federal Housing Finance Agency
FIT	feed-in tariff
GHG	greenhouse gases
GW	gigawatt, equals 1,000 megawatts.
GWh	gigawatt-hour
HVAC	heating, ventilation, and air conditioning
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
IEPR	Integrated Energy Policy Report
IOU	investor-owned utility
LABC	Los Angeles Business Council
LADWP	Los Angeles Department of Water & Power

LCOE	levelized cost-of-energy
LCR	local capacity requirement
MEA	Marin Energy Authority
MPR	market price referent
MW	megawatt, equals 1,000 kilowatts
MWh	megawatt-hour
NCPA	Northern California Power Agency
NREL	National Renewable Energy Laboratory
OPA	Ontario Power Authority
OPUC	Oregon Public Utilities Commission
PACE	property assessed clean energy
PHEV	plug-in electric vehicle
PG&E	Pacific Gas & Electric
POU	publicly-owned utility
PPA	power purchase agreement
PURPA	Public Utility Regulatory Policy Act
PV	photovoltaic
QF	qualifying facility
RAM	renewable auction mechanism
RETI	Renewable Energy Transmission Initiative
RPS	Renewable Portfolio Standard
SDG&E	San Diego Gas & Electric
SCE	Southern California Edison
SCPPA	Southern California Public Power Authority
SEER	seasonal energy efficiency ratio
SEP	supplementary energy payments
SFPUC	San Francisco Public Utilities Commission
SGIP	self generation incentive program
SJVPA	San Joaquin Valley Power Authority
SMUD	Sacramento Municipal Utility District
SVP	Silicon Valley Power
SWRCB	State Water Resources Control Board
T&D	transmission & distribution
TOD	time-of-delivery
TOU	time-of-use
TREC	tradable renewable energy credit
TURN	The Utility Ratepayer Network
UCLA	University of California Los Angeles
ZNE	zero net energy

11. Integrating Distributed Generation (DG) Into the Grid

The T&D system has changed little over the last century. It is configured to transmit electricity generated at large power plants over high voltage transmission lines to distribution substations where the voltage is reduced. The electricity then flows from the distribution substations along feeders to customers. Safety devices, like circuit breakers located at distribution substations and reclosers on the feeders, are currently constructed assuming electricity will always flow in one direction. To accept high levels of DG, at some point these safety devices must be upgraded to allow two-way flow. The relationship between distribution substations, feeders, and DG sources is shown in Figure 11-1.[360]

Figure 11-1. Distribution Substation, Feeders, and DG Sources



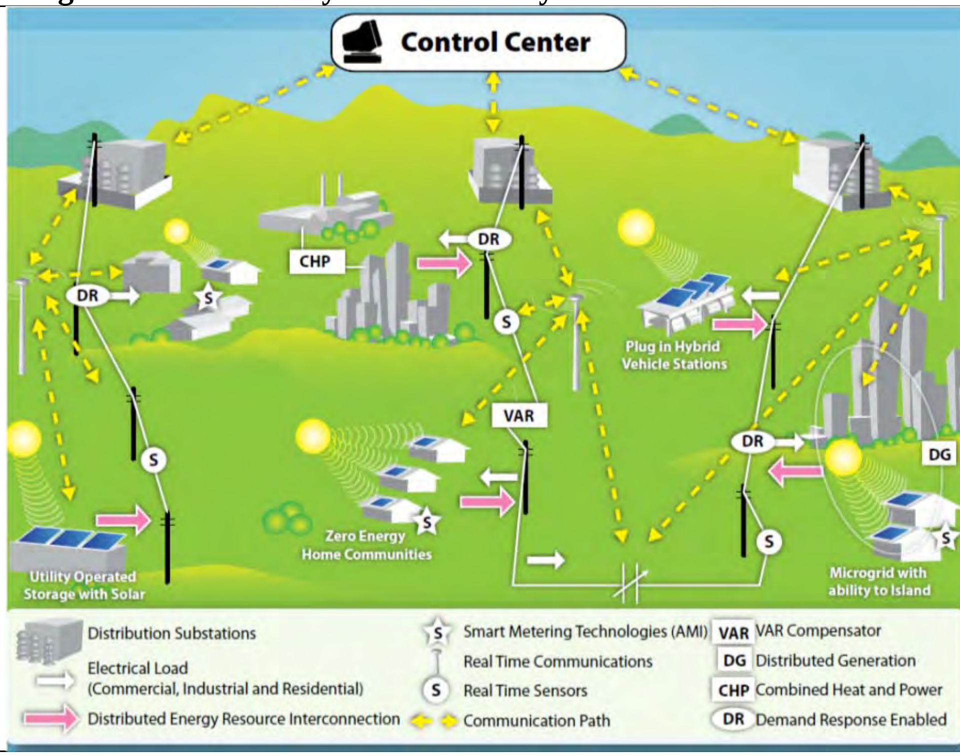
DRE = distributed renewable energy

The CEC made clear in 2007 that incorporating bidirectional capability into distribution substations and feeders is a commonsense need in a smart grid environment where higher-and-higher levels of DG are encouraged and expected, stating:[361]

- Utilities spend approximately three-fourths of their total capital budgets on distribution assets, with about two-thirds spent on upgrades/new infrastructure in most years.
- Investments will remain for 20 to 30 or more years.
- Magnitude of these investments suggests need to require utilities, before undertaking investments in non-advanced grid technologies, to demonstrate that alternative investments in advanced grid technologies that will support grid flexibility have been considered, including from a standpoint of cost-effectiveness.

The CEC's vision of a two-way distribution system that is optimized for high levels of DG is shown in Figure 11-2.

Figure 11-2. Two-Way Distribution System for DG Environment[362]



The CEC correctly identified a fully two-way distribution grid as a priority in 2007. There is no requirement that the IOUs assure full two-way flow capability in new or upgraded distribution substations as of March 2012. However, SB 17 (2009) establishes as state policy the modernization of the California's electrical grid. The objective of this smart grid policy is to maintain reliable and cost-effective electrical service while integrating high levels of distributed generation resources, demand-side resources, energy storage, and electric vehicles.[363]

Some European countries are well ahead of California in making their distribution grids compatible with high levels of DG. Netherlands is one example. The country has an average demand of about 14,000 MW.[364] Over a three-year period from 2004 through 2006, about 1,500 MW of 1 to 3 MW CHP plants were brought online in areas with a high density of greenhouses.[365] The country also has over 2,200 MW of installed wind capacity.[366]

The Netherlands has made a strategic commitment to the development of DG resources. The country is simulating where major DG development will occur and pro-actively planning necessary grid upgrades to avoid the grid becoming a bottleneck to DG development. This process is explained in the following paragraphs from a 2011 article published in the Proceedings of the Institute of Electrical and Electronics Engineers:[367]

> In The Netherlands local authorities have designated specific areas for the development of greenhouses. Each greenhouse may contain a CHP plant with a capacity in the range of 1 to 3 MVA (MW) and thus to be connected to the local medium voltage grid. Due to the high density of greenhouses in such areas, the penetration level of CHP plants in the medium-voltage grid is very high. This can amount to a total generated power of 100 MW or even more, and with loads far less than the generation power."

> The Dutch regulatory framework requires the distribution system operators to provide a connection to the distribution grid within 18 weeks upon a client's request. The capacity and structure of today's (Dutch) distribution grids in these areas does not support a connection of a large number of CHP plants. The time it takes to execute projects in the grid to secure reinforcements does not match the legal time it takes to make a grid connection for a new DG unit.
>
> To mitigate these planning issues, proactive grid planning by both the distribution system operator and the transmission system operator is necessary. To plan the grid in a proactive way, several transmission development scenarios have to be established. With the aid of these scenarios, bottlenecks in current medium voltage grids and sub-transmission grids can be identified. In each scenario, alternative grid designs have to be generated for each bottleneck. These alternatives are to be generated in such a way that the expected growth of CHP plants in each scenario is covered.

The methodical, pro-active upgrade approach being utilized by the Dutch to assure the distribution grid can absorb large amounts of DG in concentrated locations is also needed in California. However, even without such upgrades, large amounts of DG can flow onto the existing one-way system without causing safety devices to mistake DG power flows for ground faults. There is always some flow on the distribution circuits, and as long as the DG flow onto the circuit is less than the total demand on that circuit, the one-way flow will be maintained.

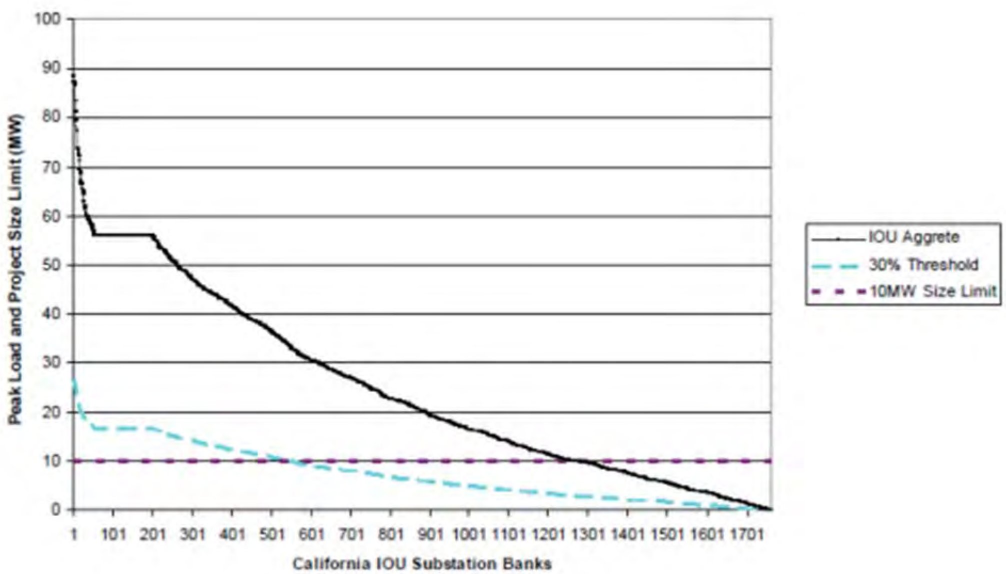
11.1 PV Capacity of Existing Distribution System

Rule 21 specifies standard interconnection, operating, and metering requirements for DG sources.[368] The CPUC has calculated in the context of Rule 21, for the entire inventory of approximately 1,700 existing IOU substations in California, the amount of distributed PV that could be accommodated with minimal interconnection cost. The CPUC states:[369]

> Rule 21 specifies maximum generator size relative to the peak load at the point of interconnection at 15%. So, for example, if a generator is interconnected on the low side of a distribution substation bank with a peak load of 20 MW, the maximum Rule 21 interconnection criteria would allow a 3 MW system (3 MW = 15% * 20 MW).
>
> However, the 15% criterion, which is established for all generators regardless of type, was adjusted to 30% for the purposes of determining the technical potential of PV. The 15% limit is established at a level where it is unlikely the generator would have a greater output than the load at the line segment, even in the lowest load hours in the off-peak hours and seasons (such as the middle of the night and in the spring). Since the peak output for photovoltaics is during the middle of the day, PV is unlikely to have any output when loads are lowest. Therefore, a 30% criterion was used for technical interconnection potential estimates. The discussion was held with utility distribution engineers, however, we did not consider formal engineering studies or Rule 21 committee deliberation since the purpose of the analysis was only to define potential.

As a component of the distributed PV renewable auction mechanism (RAM) program development process, the CPUC requested data on peak loads at all IOU substations from the IOUs and compiled that information graphically as shown in Figure 11-3. According to the CPUC, this data was obtained from IOU distribution engineers.[370] Approximately 13,300 MW of PV can be connected directly to IOU substation load banks based on the data in Figure 11-3. The supporting calculations for this estimate are provided in Table 11-1.

Figure 11-3. IOU Substation Peak Loads, 30 Percent of Peak Load



The IOUs provide about two-thirds of electric power supplied in California, with POUs like the Bay Area POUs, SMUD, LADWP, and others providing the rest.[371] Assuming the substation capacity pattern in Figure 11-3 is also representative of the non-IOU substations, the total California-wide distributed PV that could be interconnected at substation low-side load banks with no substantive substation upgrades would be [13,300/(2/3)] = 19,950 MW.

Table 11-1. Calculation of Distributed PV Interconnection Capacity to Existing IOU Substations with Minimal Interconnection Cost

Substation range	Number of substations	Calculation of distributed PV that could be interconnected with minimal substation upgrades (MW)	Total distributed PV potential (MW)
1-200	200	average peak ~60 MW x 0.30 = 18 MW	3,600
201-500	300	average peak ~45 MW x 0.30 = 13.5 MW	4,000
501-800	300	average peak ~30 MW x 0.30 = 9 MW	2,700
801-1,000	200	average peak ~20 MW x 0.30 = 6 MW	1,200
1,001-1,600	600	average peak ~10 MW x 0.30 = 3 MW	1,800
		Distributed PV total:	13,300

11.2 Upgrading Distribution System to Maximize Distributed PV

An upgrade at the substation would be necessary to accommodate back-flow in cases where a large amount of distributed PV is interconnected to single substation equipped with conventional one-way safety devices. An example would be a warehouse district with clusters of large rooftops covered with PV, that collectively could produce up to 100 percent of a substation's peak load. The safety devices on a typical 100 MW, 12 kV/69 kV substation can readily be upgraded to allow two-way power flows, also known as bidirectional power flows, for up to 100 MW of interconnected distributed PV.

PG&E is already addressing the transmission and distribution grid equipment and communication issues that could restrict the full development of rooftop PV potential in the Bay Area. The circuit breakers on over 50 percent of PG&E's 724 distribution substations are equipped with full microprocessor control.[372] 100 percent of all critical PG&E distribution substation circuit breakers will be microprocessor-controlled by 2015. Voltage optimization controls are being installed on 400 distribution feeders with high levels of PV generation or high distribution system losses. PG&E is largely resolving, through its *Smart Grid Deployment Plan 2011-2020*, distribution grid issues that could otherwise restrict rapid development of the Bay Area's full rooftop PV potential.

A distribution substation upgrade would consist of retrofitting substation metering and microprocessor-controlled protective equipment from one-way power flow to bidirectional power flow. The cost of such an upgrade for a typical 100 MW distribution substation would be approximately $500,000.[373] This is well under 1 percent of the gross capital cost of 100 MW of state-of-the-art PV at 2011 prices.

The cost to build a new 100 MW, 12 kV/69 kV substation is in the range of $25 million.[374] Even the cost of a new 100 MW distribution substation, at $25 million, is less than 10 percent of the gross capital cost of 100 MW of state-of-the-art PV at 2011 prices. The substation upgrade cost would be relatively minor compared to the gross capital cost of 100 MW of PV arrays, and would not present a substantive financial hurdle to developing a 100 MW distributed PV resource concentrated in an area served by a single existing distribution substation.

The CPUC assumes that larger PV arrays will be connected directly to the substation low-side 12 kV load bank. SDG&E estimated that the cost of a 10 MW feeder is $0.6 million per mile.[375] The cost of a 3-mile long dedicated feeder from multiple rooftop PV arrays with a combined capacity of 10 MW to the low-side bus of the substation would be less than $2 million.

The current capital cost of large commercial rooftop PV is in the range of $3,500/kW$_{dc}$.[376] This is equivalent to a cost of approximately $4,400/kW$_{ac}$.[377] The gross capital cost of 10 MW of rooftop PV at $4,400/kW$_{ac}$ would be $4,400/kW$_{ac}$ x (1,000 kW/MW) x 10 MW$_{ac}$ = $44 million. The cost to construct a dedicated feeder to interconnect 10 MW$_{ac}$ of rooftop PV would be approximately 5 percent of the gross project capital cost. This is a relatively minor cost and does not represent a financial impediment to maximizing the development of distributed PV resources.

11.3 Monitoring Grid-Connected Distributed PV

A December 2011 analysis on the integration of renewable distributed generation, conducted for the CEC, determined that accommodating back-flow conditions caused by large amounts of distributed generation on distribution circuits would not require major changes to California's basic distribution infrastructure.[378]

A primary concern expressed in the analysis is the lack of significant utility effort in California to monitor or control the dispatch of non-utility owned rooftop PV on distribution circuits. The monitoring and dispatch control of commercial-scale rooftop PV is considered essential to reliable grid operation in Germany, where approximately 25,000 MW_{dc} of distributed PV was online at the beginning of 2012.

The analysis prepared for the CEC states:[379]

> Unlike Germany, the California ISO has no visibility of the energy production of DG resources connected to the distribution system and cannot send dispatch commands to these DG resources. This is especially true for DG resources that are connected behind the meter at a customer site and the DG output is netted with the customer load. By virtue of its balancing area authority status, the California ISO must be prepared to cover the total load at the customer site in the event that the DG unit shuts down, but the amount of load being offset by DG output is typically unknown to the California ISO.
>
> The European experience shows that it is vital for the power system operator to be able to monitor the output of DG facilities as well as direct DG units to curtail dispatch when required for emergencies, such as grid reliability and safety.[380]

This analysis indicates that the current limitation on DG inflows is more administrative than technical, especially in light of PG&E's progress in upgrading distribution grid safety devices to microprocessor control.

11.4 Use of Smart Inverters in All PV Systems

Traditionally PV inverters were intentionally designed to feed as much active power, in kW or MW, as available from the solar array at unity power factor into the grid. More recently utilities and independent power providers have shown much interest in the three phase inverter's capability to also absorb and provide reactive power from and to the grid.[381]

The flow of active power and reactive power in the grid are independent from one another and largely require different control schemes. Active power control is tied to controlling grid frequency, whereas reactive power control is linked with controlling the grid voltage.

11.4.1 Control of Active Power and Frequency

In a transmission and distribution network it is necessary to keep the frequency as stable as possible because the biggest generating resources, all of which are synchronous machines, work at their most efficient point when spinning at exactly 60 cycles per second. Also, the speed governors on these machines must operate in lock-step to share the generation load between machines to meet demand. For the frequency to remain stable the generated active power must match the power demand at all times. However, many electricity consuming devices operate out-of-synch with a standard alternating current waveform where the current and voltage waveforms are synchronized. The degree of synchronization between the current and voltage waveforms is called the "power factor." When current and voltage are not in synchronization, for example because an electricity consuming device creates induction, this "out of synchronization" effect must be countered with reactive power. Some loads requiring offsetting reactive power are shown in Table 11-2.

Table 11-2. Typical Reactive Power Consuming Loads[382]

Load	Power factor
Fluorescent lighting	0.90
Heat pump and A/C	0.83
Washer	0.65
Industrial motor	0.85

11.4.2 Control of Reactive Power and Alternating Current Voltage

Although reactive power can be controlled in large generation stations, it is necessary to control voltage by injecting and absorbing reactive power at various points throughout the transmission and distribution network. Excessive voltage can adversely affect equipment and loads. Reactive power control also greatly enhances grid stability and reduces line transmission losses.

Transmission lines can, depending on load and length, either absorb or provide reactive power. The resistive power loss component, heat loss, is often insignificant in comparison to the reactive power component at very high voltage levels.

The reactive power capacity of a smart PV inverter can be used as a fast-acting static reactive power compensator, controlled through a supervisory control and data acquisition system. A major benefit of this implementation is that it comes at very little additional component cost.
At the distribution line level, smart PV inverters are used to correct the power factor by providing reactive power close to where they are being used, rather than importing them from far away. Transformers and most electrical loads are inductive in nature and therefore consume reactive power.[383]

Traditionally power factor correction is done by connecting large, paralleled capacitor banks to many of the voltage levels of the distribution system. These capacitors are strategically placed to adjust voltage along the feeder. Power factor correction and alternating current voltage regulation can be performed much more economically by distributed three-phase smart PV inverters along the feeder. This regulation will also be done in a continuous and smooth fashion, without any step changes or noticeable switching events.[384]

Germany requires PV inverters on systems 100 kW or greater in capacity to utilize smart PV inverters.[385] This same requirement should be applied in California to assure that high levels of power flow from rooftop PV systems will maintain or improve grid reliability.

11.5 IOUs and Distributed PV

In its March 2008 application to the CPUC for an urban PV project up to 500 MW, SCE expressed a high level of confidence that it can absorb thousands of MW of distributed PV without additional distribution substation infrastructure. SCE indicated that "SCE's Solar PV Program is targeted at the vast untapped resource of commercial and industrial rooftop space in SCE's service territory,"[386] and "SCE has identified numerous potential (rooftop) leasing partners whose portfolios contain several times the amount of roof space needed for even the 500 MW program."[387]

The utility stated it has the ability to balance loads at the distribution substation level to avoid having to add additional distribution infrastructure to handle this large influx of distributed PV power.[388] SCE explains:

> SCE can coordinate the Solar PV Program with customer demand shifting using existing SCE demand reduction programs on the same circuit. This will create more fully utilized distribution circuit assets. Without such coordination, much more distribution equipment may be needed to increase solar PV deployment. SCE is uniquely situated to combine solar PV Program generation, customer demand programs, and advanced distribution circuit design and operation into one unified system. This is more cost-effective than separate and uncoordinated deployment of each element on separate circuits.[389]

SCE also noted that it will be able to remotely control the output from individual PV arrays to prevent overloading distribution substations or affecting grid reliability:[390]

> The inverter can be configured with custom software to be remotely controlled. This would allow SCE to change the system output based on circuit loads or weather conditions.

As SCE states, "Because these installations will interconnect at the distribution level, they can be brought on line relatively quickly without the need to plan, permit, and construct the transmission lines."[391] This statement was repeated and expanded in the CPUC's June 18, 2009 press release regarding its approval of the 500 MW SCE urban PV project:[392]

> Added Commissioner John A. Bohn, author of the decision, "This decision is a major step forward in diversifying the mix of renewable resources in California and spurring the development of a new market niche for large scale rooftop solar applications. Unlike other generation resources, these projects can get built quickly and without the need for expensive new transmission lines. And since they are built on existing structures, these projects are extremely benign from an environmental standpoint, with neither land use, water, or air emission impacts. By authorizing both utility-owned and private development of these

> projects we hope to get the best from both types of ownership structures, promoting competition as well as fostering the rapid development of this nascent market."

The CPUC made a similar observation with its approval of the PG&E 500 MW distributed PV project in April 2010:[393]

> This solar development program has many benefits and can help the state meet its aggressive renewable power goals," said CPUC President Michael R. Peevey. "Smaller scale projects can avoid many of the pitfalls that have plagued larger renewable projects in California, including permitting and transmission challenges. Because of this, programs targeting these resources can serve as a valuable complement to the existing Renewables Portfolio Standard program.

The use of the term smaller scale in the CPUC press release is a misnomer. A 500 MW distributed PV project is the same size as a 500 MW solar thermal project at a remote desert site. Individual rooftop PV arrays in a large distributed PV project are functionally equivalent to single rows of reflective mirrors in a solar thermal project. Each rooftop or row is a contributor to a much bigger whole.

11.6 Conclusions and Recommendations

- IOUs spend about two-thirds of their total capital budgets on distribution system upgrades and new infrastructure.

- Existing California feeders and distribution substations can absorb up to approximately 20,000 MW of distributed PV without significant modification.

- The cost of upgrading a 100 MW distribution substation to full bidirectional flow is in the range of $500,000 or less. This is well under 1 percent of the cost of the potential rooftop PV capacity that could be connected to the substation. Much of the necessary microprocessor-controlled hardware is already being installed by PG&E as part of its smart grid deployment plan.

- California IOUs are not monitoring or controlling third party DG on their distribution circuits. This DG monitoring and control function is considered critical to ensure grid reliability in European countries with high levels of DG.

- IOUs state they will employ advanced distribution circuit design and operation to handle large influxes of PV power from their IOU-owned distributed PV. This same approach should be used by PG&E to monitor and control third-party DG on its distribution circuits.

- The CEC recommends that new distribution substations and existing substations to be upgraded must include advanced grid technologies that will support grid flexibility. This would include full bidirectional flow capability.

- PG&E and Bay Area POUs should be required, consistent with the SB 17 smart grid mandate, to include advanced grid technologies, including full bidirectional flow capability, in all substations and associated feeders with a near- or mid-term potential for high levels of DG development.

- Smart inverters should be required on all PV systems to assure high power quality and to permit the utility to monitor and control the inverter as needed to maintain grid reliability.

- Rule 21 should be revised to increase the minimum DG “easy interconnection” limit to 30 percent of substation peak load for PV.

- Rule 21 should not apply to distribution substations and associated feeders that are equipped with the microprocessor-controlled hardware and monitoring necessary to be fully bidirectional.