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FEDERAL ENERGY MANAGEMENT PROGRAM

California Energy Incentive Programs:

An Annual Update on Key Energy Issues and Financial Opportunities for Federal Sites in California

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Overview

A spate of recently enacted energy legislation and associated program changes is providing numerous opportunities to help California federal energy managers cut costs and meet their renewables, energy efficiency and GHG emissions goals. In April 2011, Governor Jerry Brown approved the nation's most ambitious renewable portfolio standard (RPS), which requires 33% of the state's electricity to come from renewable energy sources by 2020. The governor is placing particular emphasis on distributed generation and has called for 12,000 MW of renewable capacity to come from small sources connected to the local distribution grid. Policy changes that will support the RPS include expanded eligibility rules that fill previous gaps in incentives for certain sizes of on-site renewable energy systems. Program updates described in this newsletter include: $200 million more in funding for California Solar Initiative rebates to commercial and industrial customers; an increase in the eligible system size for the Feed-In-Tariff (FIT) from 1.5MW to 3MW; and pending changes that may allow customer-side systems to sell tradable renewable energy credits (TRECs) to entities with RPS compliance obligations in California.

Demand response and dynamic pricing tariffs are also in the spotlight, as several emerging initiatives could make these programs more attractive for federal customers. The California Independent System Operator (CAISO)[1] Proxy Demand Resource product, introduced in late 2010, allows demand response providers and end-use customers to bid their load reduction capabilities directly into the wholesale electricity market and receive compensation at the same market rate as new generation. The state's investor-owned utilities (IOUs) have also filed new three-year demand response budgets and program plans for 2012-2014 that increase the emphasis on price-responsiveness to incentivize new customer participation. Utilities are available to assist federal customers as agencies ramp up installation of intelligent metering equipment to comply with the EPACT 2005 directive on metering.[2] This compliance effort will give many facilities their first viable opportunity to benefit from financial incentives and electricity cost savings offered by price-responsive tariffs and demand response programs.

California Increases Renewable Goals and Expands Distributed Generation Options

In April 2011, Governor Jerry Brown signed into law a requirement that California electricity providers procure 33% of their electricity from renewable sources by the end of 2020. The landmark legislation also sets an interim target of 25% by the end of 2016. This new renewable portfolio standard (RPS) applies to all electricity retailers: IOUs, publicly owned utilities and 3rd-party providers. To meet the new mandate, the governor has suggested electricity be sourced from a combination of 12,000 MW of local distributed generation (DG) and 8,000 MW of new utility-scale capacity. Expected outcomes of this landmark legislation include increased stability

[1] CAISO operates California's power grid and wholesale electric markets, covering most of the geography of the state. For more information visit CAISO's website: www.caiso.com/

[2] More details on requirements for Federal facilities under EPACT 2005 may be found on FEMP's website: www1.eere.energy.gov/femp/regulations/epact2005.html

of renewable energy programs and incentives in the long term, in contrast to the "boom and bust" cycles of program availability and funding that have occurred in past years.

Federal energy managers should be aware of the range of available DG programs as a starting point for understanding which might be appropriate for their facility. California's programs fall into two categories:

1. Customer-side generation, also called self-generation or "behind the meter" systems, which are typically sized to directly serve the customer's on-site electricity needs , generally 5 MW or less; and
2. Utility-side or wholesale procurement, which can be any size and can be located at a customer site, but are connected directly to the utility distribution system and export all electricity to the utility.

See **Table 1** for a summary of key distinctions between customer-side and utility-side distributed generation (DG).

Table 1. Key Attributes of Customer-Side vs. Utility-Side Distributed Generation.

	Customer-side (Self-) Generation	**Utility-side Procurement**
Project Size	Up to 5 MW (most under 2 MW), systems sized to serve/offset customer load. Not designed for export	Any size, specifically for export of electricity generated. Sized larger than customer onsite load if located on and serving customer site.
Incentives	Eligible for up-front financial incentives.	Eligible for contracted procurement but not eligible for incentives, rebates or subsidies.
RPS/RECS	System owner retains RECs and may sell them on the voluntary market, and in the future may be able to sell them to entities with RPS compliance obligations in California.[3]	Qualifies for RPS. RECs typically transfer to buyer of the renewable energy.
Net Energy Metering	Projects may qualify for Net Energy Metering and Net Surplus Compensation for generation above site's consumption.	Projects do not qualify for Net Energy Metering.
Interconnection	Generator pays interconnection charges.	Most are exempt from interconnection charges.
Programs	California Solar Initiative (CSI), Self-Generation Incentive Program (SGIP), Emerging Renewables Program (ERP).	Feed-in Tariff (FIT), Renewable Auction Mechanism (RAM), Qualifying Facility Program, Utility system-side solar PV programs.

Source: Jeanne Clinton, CPUC. Presentation for the Governor's Local Energy Generation Conference, July 25, 2011.

[3] Proposed changes are under consideration that will allow these projects to qualify for the RPS and to sell tradable renewable energy credits (TRECS) on the compliance REC market.

CSI Gets $200 Million Boost for Commercial/Industrial Rebates

The California Solar Initiative (CSI) is once again flush with rebate funds for solar PV installations. In September 2011, Governor Brown signed legislation that provided an additional $200 million specifically for institutional, commercial and industrial customers. As of October 15, 2011, the remaining capacity of rebates available from the three electric IOUs totaled over 106 MW and the rebate levels for government entities were at Step 8 ($1.10/watt for up-front payments or $0.15 per kWh for performance-based payments). Federal facilities interested in taking advantage of the financial incentives should move quickly, as the incentive rates will continue to decline. To check the latest incentive rate levels, see the CSI Trigger Point Tracker at www.csi-trigger.com/.

SGIP Updated

In September 2011, the CPUC approved a proposed decision that restructures incentives and modifies technology eligibility rules for the Self Generation Incentive Program (SGIP). The SGIP, available to customers of the state's four electric and gas IOUs, will provide $83 million in rebates annually for a variety of non-solar on-site electricity generation technologies. The decision extends current funding levels for the program through 2016 and bases technology eligibility on greenhouse gas (GHG) reduction capability. The program is temporarily suspended until a new program handbook is adopted.

As amended by the decision, participants will now be required to complete energy efficiency audits before receiving incentives. While some incentive levels are slightly reduced (e.g., wind turbine rebates are reduced to $1.25/watt from $1.50/watt), new technologies (e.g., pressure-reducing turbines) have been added to the eligibility list. Other eligible technologies include bottoming-cycle CHP, conventional CHP (gas turbines, micro-turbines and internal combustion engines), biogas, fuel cells and stand-alone advanced energy storage. There is no maximum system size, but incentive payments are capped at 3MW, with the first MW earning 100% of the calculated incentive, the second MW receiving 50%, and the third 25%. Incentive levels will decline 10% per year beginning in 2013. Systems that are 30 kW or larger will receive 50% up-front payment and 50% performance-based payment based on kWh generation. The decision may be viewed at: http://docs.cpuc.ca.gov/published/Final_decision/143459.htm. CPUC's SGIP web page provides links to the four utilities' incentive programs as well as impact reports and other information here: www.cpuc.ca.gov/PUC/energy/DistGen/sgip/.

Eligible Technologies Expanded for Net Energy Metering; Net Surplus Compensation Now Available for Systems up to 1 MW

On October 6, 2011, Governor Brown signed SB 489 into law, expanding the list of technologies eligible for Net Energy Metering to include all renewable technologies including biomass and biogas. Historically, customers with net metered distributed generation were allowed to fully offset their annual electricity use, but would not receive any compensation for net excess generation produced over the course of a year. Assembly Bill 920, effective January 1, 2011, allows customers with on-site renewable energy systems that are enrolled in Net Energy Metering (solar and wind systems up to 30 kW) or Expanded Net Energy Metering (systems up to 1MW) to receive compensation for surplus electricity generated over the course of the true-up period (typically 12 billing months). The net surplus compensation (NSC) rate is based on a rolling 12-month average of spot market prices and will fluctuate each month; in October the

NSC rate was about 3.7 cents per kWh. Although renewable energy credits (RECs) associated with the electricity produced and used on-site continues to remain with the customer, RECs from surplus electricity, for which the customer receives compensation, will transfer to the utility.

For more information about Net Energy Metering and Net Surplus Compensation, visit the utilities' websites:
PG&E: www.pge.com/myhome/saveenergymoney/solarenergy/nembilling/faq/
SCE: www.sce.com/customergeneration/nem-ab920.htm#Q34
SDG&E: www.sdge.com/nem/questions_ab920.shtml.

Feed-In Tariff Legislation Expands System Size Eligibility; Additional Rule Changes Pending

In April 2011, Senate Bill X1 2 amended the existing Feed-in-Tariff (FIT), increasing the maximum eligible system size from 1.5MW to 3 MW. The recent amendments have yet to be incorporated into the program; as of late October, the CPUC was considering significant further changes to the program. The FIT enables customer renewable energy generators to sell electricity to their utilities under 10- 15- or 20-year contracts, with payment price based on the CPUC's Market Price Referent (MPR)[4]. As a "must take" power purchase agreement program, utilities are required to purchase all electricity generated under FIT contracts. Participants may not combine the FIT with participation in any of the programs that involve public benefit funds including CSI and SGIP, or with any of the net energy metering programs.

More information is available on the CPUC's FIT website: www.cpuc.ca.gov/feedintariff. Federal facilities can also check with their utility representatives for updates.

Tradable RECs Authorized

In January 2011, the CPUC authorized the use of tradable renewable energy credits (TRECs) for use in meeting the state's RPS. Renewable energy credits (RECs) represent the attributes of the renewable energy separately from the generated energy itself. Prior to the decision, utilities were required to purchase renewable energy and renewable energy credits together, on what has been referred to as a "bundled" basis. Now, renewable energy and its respective credits can be "unbundled" and purchased and/or traded separately. The decision allows owners of RPS-eligible generation to sell their RECs on the compliance market, which in the long run is expected to bring higher prices than the current voluntary markets. Once owners sell the RECs they relinquish any further right to claim that they are generating renewable electricity (or monetize it).

This price for TRECs is initially capped at $50/MWh (5¢/kWh). IOUs and other participating energy providers may meet up to 25% of their RPS requirement through purchase of TRECs from any RPS-eligible source. Currently only utility-side DG sources (e.g., through the FIT, RAM, Qualifying Facility and Utility PV programs) are RPS eligible, however the new RPS legislation sets different limits on the use of TRECs and the CPUC will likely develop new

[4] The Market Price Referent represents the market price of electricity which takes into consideration the ownership, operating and fixed-price fuel costs associated with electricity from new generating facilities. The current Market Price Referent table may be viewed at: www.cpuc.ca.gov/PUC/energy/Renewables/Feed-in+Tariff+Price.htm.

TREC rules under the new RPS. One change under consideration is a proposal to extend RPS-eligibility to customer-side installations (e.g., CSI and SGIP participants).

Renewable Auction Mechanism: Potential Opportunity to Deploy Solar on Federal Sites

In December 2010, the CPUC adopted the Renewable Auction Mechanism (RAM)[5], a reverse auction for systems between 1 and 20 MW, as the primary procurement vehicle for system-side renewable DG that meets the state's RPS requirements. The state's IOUs are authorized to procure a combined total of 1,000 MW during the first two years of the program. Thereafter, the capacity authorization will be determined by each utility's need for system-side DG.

RAM may also prove useful in contributing to the goals of the DOE's SunShot Initiative[6] to deploy solar projects on federal properties. Federal agencies that have land or buildings available for lease to 3rd-party development have a terrific opportunity now to attract projects as renewable project developers begin to map out the state in search of promising sites. Utilities are also looking to deploy distributed generation in locations where there are electric system bottlenecks.

See **Table 2** for a summary of DG incentive programs potentially relevant to federal customers.

Table 2. California Distributed Generation Programs Relevant to Federal Customers.

Program Name	Program Description	Website
Customer-side (Self-) Generation		
California Solar Initiative (CSI) – Solar Electric	Expected performance-based buydowns (EPBB) for solar electric DG systems up to 30 kW and performance-based incentives (PBI) for systems up to 1 MW. Rebate levels decline in steps based on the MW volume of confirmed incentive reservations.	www.cpuc.ca.gov/NR/rdonlyres/68C027C4-0890-4320-9BBA-65FDC482894D/0/CSIProgramHandbookDecember2009_v2.pdf and http://www.csi-trigger.com/ .
CSI Solar Thermal Program/ Solar Water Heating	Up-front rebates (up to $500,000) for solar thermal systems to replace electricity or natural gas water-heating systems. Payments based on calculated production.	www.gosolarcalifornia.org/solarwater/
Self Generation Incentive Program (SGIP)	Incentives for systems up to 3MW include wind turbines, CHP, advanced energy storage and biogas and all-electric or CHP fuel cell. Technologies must demonstrate GHG emissions reductions.	www.cpuc.ca.gov/PUC/energy/DistGen/sgip/
Emerging Renewables Program	Rebates for small (<30 kW) wind and renewable fuel cell self-generation equipment. Program is temporarily suspended while it undergoes revisions.	www.energy.ca.gov/renewables/emerging_renewables/index.html

[5] Appendix A of the RAM Decision (D.10-12-048) contains a detailed summary of the program: docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/128432.pdf

[6] The SunShot Initiative is a Department of Energy-sponsored national effort to deploy 200 MW of solar energy on federal civilian sites. For details, visit the SunShot website: www1.eere.energy.gov/solar/sunshot/.

Utility-side Procurement		
Feed In Tariffs (FIT)	Customer distributed renewable generators (up to 1.5MW under current rules; up to 3MW under proposed rules) may enter into 10-, 15- or 20- year contracts with utilities to sell electricity generated from RPS-eligible renewable sources[7] at a fixed price for each kWh exported to the grid. Customers may either sell 100% of electricity production or first offset on-site load and sell only the net excess. Only open to projects not already receiving incentives under CSI, SGIP, Net Metering or similar programs. As of October 2011 the CPUC is considering significant changes to the program	www.cpuc.ca.gov/PUC/energy/Renewables/hot/feedintariffs.htm
Renewable Auction Mechanism (RAM)	New reverse auction mechanism for utility-side procurement of RPS-eligible renewable distributed electricity generation from smaller systems up to 20 MW. Potentially relevant to federal agencies interested in leasing property to renewable project developers.	www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm
Qualifying Facility Program	Electricity procurement by the three electric IOUs from self-generators that may have surplus energy or that generate electricity as a byproduct of other activities (e.g., a cogeneration facility).	www.cpuc.ca.gov/PUC/energy/Procurement/QF/.
Utility solar PV programs	Utility-owned and independent power producer-owned distributed solar PV projects. PG&E: systems 1 to 20 MW. SCE and SDG&E: systems 1-2 MW. Potentially relevant to federal agencies interested in leasing property to renewable project developers.	www.cpuc.ca.gov/PUC/energy/Renewables/SCE+Solar+PV+Program.htm

Demand Response and Price-Responsive Tariffs

In August 2010, the California Independent System Operator (CAISO) introduced a new mechanism that has the potential to make demand response participation significantly more attractive to large customers. CAISO's Proxy Demand Resource (PDR)[8] product allows registered entities to supply demand response (DR) resources to the wholesale electricity market at the same market price as new electricity generation. The new program opens up CAISO's day-ahead and real-time markets to registered entities who can guarantee at least 100 kW of direct or aggregated electricity curtailment. Individual end-use customers with large enough demand can apply for participation, though utilities and large demand response aggregators will likely make up most of the program participants. Under current rules only direct access customers are qualified to bid demand response directly into the CAISO markets; utility bundled customers must participate through programs offered by their utilities. To bid proxy demand resources into

[7] RPS-eligible technologies include solar PV, solar thermal electric, wind, biomass, geothermal, small hydroelectric, landfill gas, wave energy, biodiesel and fuel cells using renewable fuels.
[8] A Proxy Demand Resource FAQ may be found on CAISO's website: www.caiso.com/participate/Pages/Load/DemandResponse/Default.aspx

the CAISO markets, a large customer or demand response provider must become a “scheduling coordinator” or hire the services of one to submit bids on its behalf. Federal customers who wish to learn about their options for participating in the Proxy Demand Resource program should contact their utility representative.

Proposed 2012-2014 Demand Response Portfolio Shifts Emphasis to Price-Responsive Programs

Historically, the state’s electric IOUs’ DR program portfolios have focused primarily on maintaining electric system reliability during times of peak demand and other stresses on the grid. However the CPUC and utilities are looking to expand the role of DR in an integrated approach to reducing electricity usage and demand, along with incorporating renewable energy into the grid. In accordance with regulatory initiatives, the IOUs’ proposed budgets and plans for the next three-year cycle of demand response programs (2012-2014) emphasize expanding the price-responsive programs (e.g., Demand Bidding Program, Critical Peak Pricing, Peak Day Pricing) while beginning to migrate away from reliability-based DR (e.g., Base Interruptible Program). Key activities include modifying retail DR programs for participation in the CAISO markets and continuing efforts to integrate all demand-side management activities. Program details continue to be in flux as the CPUC considers stakeholder input; final approval is expected at the end of 2011.

Individual utility proposals that may affect federal customers if approved include: 1) PG&E aiming to transition Demand Bidding Program (DBP) customers to the PeakChoice™ program starting in 2012, ending DBP by December 31, 2012 in an effort to reduce duplication of program features; 2) PG&E proposing several changes to PeakChoice™ including expanding eligibility to direct access customers; 3) SCE seeking to simplify information and educational materials in order to improve customer understanding of the programs; and 4) SDG&E asking the CPUC to disallow ”double-dipping” across several programs including the Critical Peak Pricing, Capacity Bidding, Demand Bidding, and any aggregator-managed programs.

Auto-DR Provides “Double-Dip” Incentives; Customers Retain Control

The utilities also propose expanding the Auto-DR program in 2012-2104 to help increase their participating loads in DR events, particularly for those in voluntary DR programs such as DBP. The proposals include continuation of the successful Technical Assistance and Technology Incentive (TA/TI) programs, which offer a generous “double-dipping” approach: customers can receive one level of incentives for regular curtailment-enabling equipment (up to $125 per kW of verified load reduction) plus additional financial incentives for installing auto-DR equipment for a total of up to $300 per kW of verified load reduction. Auto-DR is open to customers participating in the Demand Bidding Program and Critical Peak Pricing (CPP) or Peak Day Pricing tariffs. PG&E also offers auto-DR to PeakChoice customers.

Facilities installing smart meters for EPACT 2005 compliance may find this an opportune time to consider adding or upgrading energy management control systems (EMCS) that can be enabled for DR and Auto-DR. Equipment and measures that may qualify for incentives include repair, upgrade or reprogramming of an existing EMCS, new EMCS hardware or software, wired and wireless lighting controls, and just about any device capable of receiving curtailment signals including HVAC, motors, fans, audio and video equipment, plug strips and occupancy sensors.

Federal energy managers should be aware that while Auto-DR provides the ability to fully automate load curtailment for peak pricing or demand response events, it does not give the utility or ISO direct control over the system. Customers choose how to program the automation and always retain the ability to override the settings on days when they choose not to curtail load. As the DR landscape continues to evolve, facility and energy managers are advised to make sure to install the most interoperable technology available (both hardware and software), in order to provide maximum flexibility for switching programs or for participating in future programs.

Dynamic Pricing Programs: Federal Agencies Respond

Between 2008 and 2010, large customers of the IOUs that had previously been on standard time-of-use (TOU) rates were defaulted to dynamic pricing programs in which peak prices spike to many times higher than the usual level on a finite number of event days. Critical Peak Pricing (CPP) became the default rate for SDG&E commercial and industrial (C/I) customers with demand of 20 kW or greater and for SCE C/I customers with demand of at least 200 kW. PG&E adopted Peak Day Pricing (PDP) as the default rate for C/I and agricultural customers in 2010. Rollout of PDP and CPP to small and medium C/I customers (under 200kW) of PG&E and SCE is now scheduled for November 2012 to allow time for some program changes.

These dynamic pricing tariffs reward customers with lower year-round electric rates in exchange for exposing them to higher prices during a limited number of peak events. Federal customers who opt to remain on these rates have a terrific opportunity to reduce annual electricity bills by curtailing load during peak events. Facilities also have an option to further insure against exposure to the higher peak prices by taking advantage of the Capacity Reservation Charge (CRC) program. Under CRC, customers reserve a specific amount of electricity that will be needed to meet operational needs during peak events and pay a fixed monthly charge based on the amount of electricity reserved. During a peak pricing event, all of a facility's electricity use up to the level of its reserved capacity will be protected from the higher prices.

Under the rollout to the new default rates, customers were given the option to opt-out to a standard TOU or other available rate. In an August 2010 study[9] Freeman Sullivan & Co. report that after two years of the program 68% of SDG&E customers that defaulted to CPP have remained on the tariff. In the federal sector, responses to the rates across the state varied as well.

- SSA's Hagel Federal Building in Richmond, CA elected to remain on PDP and some accounts at Fort Irwin have remained on CPP. Both facilities report that they are satisfied with the programs; they are curtailing enough load during peak events to come out financially ahead on the rate for the year.
- Some federal customers, including NASA's Jet Propulsion Laboratory and multiple Navy facilities in Southern California, were not automatically eligible for CPP because they were already participating in the voluntary Demand Bidding Program (DBP) and customers are not allowed to participate in more than one program with concurrent day-ahead notification (DBP employs day-ahead notification as do CPP and PDP). Both facilities opted to remain with DBP.

[9] "SDG&E Non-Residential Critical Peak Pricing Enrollment Choices " is available at: fscgroup.com/news/sdge-non-residential-default-cpp-choices.pdf

- Vandenberg AFB chose to opt out of PDP and sign up for DBP as well, due to having a highly variable load and energy-intensive mission-critical activities that could not be curtailed if they occurred on a peak event day.

An agency with facilities in PG&E territory initially opted out of PDP because it did not have the data to determine whether the new tariff was a good choice. However it may be an ideal candidate for PDP because much of its heaviest activity takes place overnight, during times when peak events will not be called. PG&E is currently working with the agency on an analysis to determine how much they might be able to save by opting back into PDP.

Utilities' Online Energy Management Tools Provide Flexible Energy Analysis Capability

The state's three electric IOUs now provide free online tools that provide flexible energy management options for any facility regardless of whether or not there is an energy management control system or sub-metering in place. For each installed interval meter, the tools give facility managers the ability to: 1) view energy use data in 15-minute intervals; 2) monitor and control demand response participation; 3) generate detailed reports (e.g., comparisons of current and historical load profiles and energy use comparisons between sites or meters, including normalization of the data); and 4) run energy use scenarios to inform decisions about optimal demand response and/or dynamic pricing tariffs for a facility. Links to the tools and instructions are available on the utilities' websites:

- PG&E InterAct: /www.pge.com/mybusiness/energysavingsrebates/demandresponse/tools/
- SCE Energy Manager Programs: www.sce.com/business/energy-solutions/sce-energy-manager.htm
- SDG&E KWickview Online Energy Monitor: www.sdge.com/business/rebatesincentives/programs/kwickview.shtml.

New FERC Ruling May Boost Demand Response Participation Nationwide

In March 2011, the Federal Energy Regulatory Commission (FERC) issued Order 745, which establishes a nationwide standard for compensation for demand response (DR) in wholesale markets. The order ended a lengthy proceeding aimed at reducing barriers to DR participation in wholesale markets. The order sets compensation for DR resources at the same market price as generation resources, known as full locational marginal price (LMP).[10] While the CAISO's Proxy Demand Resource (PDR) also provides rules for bidding demand response into the California wholesale markets, the FERC ruling could have further implications for the types of DR programs offered, program eligibility, and compensation in the future. Details for participation and compensation under Order 745 have yet to be finalized for each region's independent system operator (ISO), and the potential impacts on CAISO's PDR in California are unclear. Federal energy managers are advised to keep aware of the issue by following updates from CAISO[11] and talking with their utility representatives.

[10] For more information see the CPUC's web page on Locational Marginal Pricing: www.cpuc.ca.gov/PUC/energy/wholesale/01a_cawholesale/MRTU/01_lmp.htm.

[11] Updates and information may be found on CAISO's website at: www.caiso.com/.

Energy Efficiency Programs

As the record $3.1 billion energy efficiency program slate for 2010-2012 enters its final year, federal energy managers still have time to take advantage of the current array of generous financial incentives and technical assistance available from the states' investor-owned utilities (IOUs). Proceedings at the CPUC are underway to extend the current programs with a year of bridge funding for 2013, with the expectation that the next three-year funding cycle will be 2014-2016.

While the primary energy efficiency program offerings have remained the same throughout the current cycle, the IOUs have implemented several changes this year that in some cases present new opportunities for federal facilities. See **Table 3** for a summary of current utility and third-party energy efficiency programs relevant to federal customers.

Table 2. Summary of IOU and Third-Party Energy Efficiency Programs Relevant to Federal Customers.

Utility Service Territory	Program Name	Program Description
PG&E, SCE*, SDG&E	Statewide Customized Offering for Business, also called Customized Retrofit (PG&E), Customized Solutions (SCE), Energy Efficiency Business Incentives (SDG&E)	Provides financial incentives for installation of high-efficiency equipment or systems (e.g., interior and exterior lighting, chiller replacements, variable speed drives, window film), in existing buildings. Incentives are based on the estimated energy usage or peak demand savings resulting from the installation.
	Business Rebates (PG&E); Express Solutions (SCE); Energy Efficiency Business Rebates (SDG&E)	Provides standardized rebates for specific types of energy efficient equipment (e.g., lighting, HVAC, boilers, insulation, window film, motors, plug load occupancy equipment). Paid at prescribed per-unit rate, up to 100% of total measure costs.
	Integrated Energy Audit Services	Provides no-cost or low-cost integrated energy audits and engineering studies to identify all viable energy savings and demand reduction opportunities including retro-commissioning, retrofit opportunities and demand response.
PG&E, SCE, SDG&E, So Cal Gas**	Commercial New Construction – Savings by Design	Provides financial incentives to building owners (up to $500,000) and design teams (up to $5,000) as well as design assistance and other tools and resources for high-performance commercial new building design and construction. Awards an additional 10% bonus for each of the following: 1) LEED certification; 2) installation of end-use monitoring technology; and 3) enhanced commissioning.
	Retro-commissioning (RCx) Program	Provides diagnostic and engineering resources as well as incentives to optimize existing equipment and systems (e.g., HVAC, lighting and control systems) in order to improve energy efficiency through tune-ups and low- or no-cost repairs.

PG&E, SDG&E, So Cal Gas	Zero Percent On-Bill Financing	Offers zero-percent on-bill financing (up to $250,000) for qualifying energy-efficient equipment installed via rebate and incentive programs.
PG&E	LED Streetlights	Provides assistance and financial incentives to customers who replace or upgrade their existing streetlights with PG&E-approved LED streetlights.
	Customized Retrofit – Demand Response	Provides financial incentives specifically for installation of demand response-enabling technologies in customized retrofits.
PG&E, SCE	UESC	Provides turnkey financed projects to federal customers.
SDG&E	Energy Savings Bid Program	Allows customers to propose the incentive amount (up to 100% of project costs) for gas or electric efficiency retrofit projects that save at least 500,000 kWh or 25,000 therms annually. Projects may comprise multiple customers and sites.
So Cal Gas	Energy Efficiency Calculated Incentive Program	Provides incentives of up to $1 million per project, and up to $2 million per premise per year for installing energy-efficient equipment or processes, equipment replacement or process improvements, or for new construction projects.
	Rebates for General Business Equipment	Provides prescriptive rebates for installing specific energy-efficient equipment and measures including water heaters, boilers, pipe insulation and steam traps.

* SCE does not provide financial incentives for natural gas measures; within SCE's electric service territory, financial incentives for natural gas measures are offered by SoCal Gas.

** SDG&E's retro-commissioning program is administered by Portland Energy Conservation, Inc. (PECI).

Zero Interest On-Bill Financing Now Available to Federal Customers throughout California

In 2011, PG&E joined the other three IOUs in offering zero percent financing with on-bill repayment for a variety of technologies installed under the utilities' energy efficiency incentive and rebate programs. Institutional customers are eligible for interest-free loans of up to $250,000 for installation of qualifying efficient lighting, refrigeration and HVAC equipment, and LED streetlights. This program provides a powerful tool for federal managers looking for ways to complete more energy projects without a large outlay of cash. In some cases, the payments can be less than the monthly dollar savings from the energy efficiency measures, allowing project costs to be fully paid out of the savings. The loan term is determined by the payback period of the installed equipment and is calculated based on the estimated annual energy savings.

Detailed information about the on-bill financing programs can be found on the utilities' websites:
www.pge.com/mybusiness/energysavingsrebates/rebatesincentives/taxcredit/onbillfinancing/
www.sce.com/business/onbill/on-bill-financing.htm
www.sdge.com/business/rebatesincentives/programs/onbillfinancing.shtml
www.socalgas.com/for-your-business/rebates/zero-interest.shtml.

The Integrated Energy Audit: A No-risk Tool to Maximize Energy Saving Opportunities

The IOUs' integrated energy audits provide federal energy managers with a no-risk vehicle for uncovering the full range of available opportunities for demand-side strategies, including energy efficiency and conservation, demand response, time-of-use rate management and self-generation (including renewables). Investor-owned utilities are now making integrated audits and projects "business as usual." Integrated audits are typically available for no cost to larger customers (demand over 200 kW), and are ideal for planning appropriations-funded projects. PG&E also provides these services to smaller single-building facilities such as the U.S. EPA laboratory in Richmond, CA.

The GSA commissioned a study for the Chet Holifield Federal Building in Laguna Niguel which was completed in 2010. The integrated energy audit identified no- and low cost measures that could provide significant savings and short payback periods, as well as higher capital-intensive efficiency measures. Ten of fourteen recommended efficiency measures offered payback times of well under ten years, ranging from zero to 7.4 years and averaging just over 3.3 years. See **Table 4** for several of the key recommended measures with estimated annual energy savings and simple payback times (accounting for incentives).

Table 4. Chet Holifield Integrated Audit: Selected List of Recommended Efficiency Measures.

Measure	Investment Level	Estimated Annual Energy Savings	Simple Payback with Incentive (yrs)
Raise computer room setpoint temperature	No cost	26,400 kWh	0
Intall premium efficiency motors when existing motors need replacing or rewinding	Low cost	5,300 kWh	2.4
Control lighting fixtures based on computer room occupancy	Low cost	34,700 kWh	1.3
Install occupancy sensors on restroom lighting	Low cost	7,742 kWh	6.5
Install variable frequency drives (VFDs) for some exhaust fans	Low cost	8,500 kWh	7.4
Reduce lighting levels in overlit office areas	Capital investment	930,000 kWh	0.1
Install a higher efficiency chiller	Capital investment	44,000 kWh	5.6
Install VFDs on hot water pumps	Capital investment	27,700 kWh	5.8

Utilities Look to Dramatically Increase Rate of Building Benchmarking

The state's four IOUs began benchmarking all non-residential facilities participating in any of their energy efficiency or demand response programs starting January 1, 2010. In their first annual benchmarking report[12] the utilities report that they benchmarked a combined total of

[12] The "Joint IOU 2010 Benchmarking Report" was filed on July 1, 2011 by PG&E on behalf of all four of the state's IOUs. The report can be viewed on PG&E's website: www.pge.com/regulation/EnergyEfficiency2009-2011-Portfolio/Other-Docs/Joint/2011/EnergyEfficiency2009-2011-Portfolio_Other-Doc_Joint_20110701_212891.pdf

almost 4,800 buildings and conducted 47 customer workshops with nearly 1,000 participants in 2010. However, the results are trending far short of meeting benchmarking targets specified by the CPUC. See **Table 5** for a summary of the benchmarking requirements for the 2010-2012 program cycle and first year results.

Table 5. 2010-2012 California Commercial Building Benchmarking Requirements and First Year Results.

Utility	Number of buildings required to be benchmarked 2010-2012	Buildings benchmarked in 2010
PG&E	50,000	1,380
SCE	50,000	425
SDG&E	20,000	1,794
So Cal Gas	Not specified	1,218

In order to address more buildings without requiring customers to benchmark prior to participating in incentive programs, the IOUs will distribute proxy benchmarks using available data. However, the utilities strongly encourage customers to obtain more comprehensive benchmarking scores for their facilities and to use their Automated Benchmarking Service for the ongoing energy management benefits it provides.

Federal energy managers in California have a unique opportunity to receive technical assistance and training from their utilities to help them meet their building benchmarking requirements under the Energy Independence and Security Act of 2007 (EISA).[13] To get started, facility managers can sign up for the benchmarking service by creating an account with ENERGY STAR Portfolio Manager (www.energystar.gov/istar/pmpam/). More information is available on each of the utilities' benchmarking web pages:
PG&E: www.pge.com/benchmarking/
SCE: www.sce.com/business/energy-solutions/benchmarking.htm
SDG&E: www.sdge.com/business/rebatesincentives/benchmarking/
So Cal Gas: www.socalgas.com/for-your-business/conserve-energy/benchmarking.shtml.

[13] More information about EISA 2007 benchmarking requirements is available on FEMP's website: www1.eere.energy.gov/femp/regulations/eisa.html

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