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THE CO_2 ABATEMENT POTENTIAL OF CALIFORNIA'S MID-SIZED COMMERCIAL BUILDINGS

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Glossary

CA	California
CARB	California Air Resources Board
CEC	California Energy Commission
CEUS	California End-Use Survey
CHP	combined heat and power
DER	distributed energy resources
DER-CAM	Distributed Energy Resources Customer Adoption Model
DG	distributed generation
FC	fuel cell
FiT	feed-in tariff
GAMS	General Algebraic Modeling System
GHG	greenhouse gas
GW	gigawatt
HX	heat exchanger
ICE	internal combustion engine
LADWP	Los Angeles Department of Water and Power
LBNL	Lawrence Berkeley National Laboratory (Berkeley Lab)
MILP	mixed integer linear program
MW	megawatt
PG&E	Pacific Gas and Electric
PQR	power quality and reliability
PV	photovoltaics
SCE	Southern California Edison
SCAQMD	South Coast Air Quality Management District
SDG&E	San Diego Gas and Electric
SGIP	self generation incentive program
tNOx	metric ton of NOx
tCO_2	metric ton of CO_2
TNRCC	Texas Natural Resources and Conservation Commission

TOU	Time-of-Use tariff

Abstract

The Ernest Orlando Lawrence Berkeley National Laboratory (LBNL) is working with the California Energy Commission (CEC) to determine the potential role of commercial sector distributed generation (DG) with combined heat and power (CHP) capability deployment in greenhouse gas emissions (GHG) reductions. CHP applications at large industrial sites are well known, and a large share of their potential has already been harvested. In contrast, relatively little attention has been paid to the potential of medium-sized commercial buildings, i.e. ones with peak electric loads ranging from 100 kW to 5 MW. We examine how this sector might implement DG with CHP in cost minimizing microgrids that are able to adopt and operate various energy technologies, such as solar photovoltaics (PV), on-site thermal generation, heat exchangers, solar thermal collectors, absorption chillers, and storage systems. We apply a mixed-integer linear program (MILP) that minimizes a site's annual energy costs as its objective. Using 138 representative mid-sized commercial sites in California (CA), existing tariffs of three major electricity distribution ultilities, and performance data of available technology in 2020, we find the GHG reduction potential for this CA commercial sector segment, which represents about 35% of total statewide commercial sector sales. Under the assumptions made, in a reference case, this segment is estimated to be capable of economically installing 1.4 GW of CHP, 35% of the California Air Resources Board (CARB) statewide 4 GW goal for total incremental CHP deployment by 2020. However, because CARB's assumed utilization is far higher than is found by the MILP, the adopted CHP only contributes 19% of the CO_2 target. Several sensitivity runs were completed. One applies a simple feed-in tariff similar to net metering, and another includes a generous self-generation incentive program (SGIP) subsidy for fuel cells. The feed-in tariff proves ineffective at stimulating CHP deployment, while the SGIP buy down is more powerful. The attractiveness of CHP varies widely by climate zone and service territory, but in general, hotter inland areas and San Diego are the more attractive regions because high cooling loads achieve higher equipment utilization. Additionally, large office buildings are surprisingly good hosts for CHP, so large office buildings in San Diego and hotter urban centers emerge as promising target hosts. Overall the effect on CO_2 emissions is limited, never exceeding 27 % of the CARB target. Nonetheless, results suggest that the CO_2 emissions abatement potential of CHP in mid-sized CA buildings is significant, and much more promising than is typically assumed.

1.0 Introduction

A *microgrid* is herein defined as a cluster of electricity sources and (possibly controllable) loads in one or more locations that are connected to the traditional wider power system, or *macrogrid*, but which may, as circumstances or economics dictate, disconnect from it and operate as an island, at least for short periods (see Microgrid Symposiums 2005-2009, and Hatziargyriou et al. 2007). Please note that microgrids can consist of multiple buildings/locations or just of a single building/location and in this work microgrids are considered to be a single building. The successful deployment of microgrids will depend heavily on the economics of distributed energy resources (DER) in general, and upon the early success of small clusters of mixed technology generation, grouped with storage, and controllable loads. The potential benefits of microgrids are multi-faceted, but from the adopters' perspective, there are two major groupings: 1) the cost, efficiency, and environmental benefits (including possible emissions credits) of combined heat and power (CHP), which is the focus of this study, and 2) the power quality and reliability (PQR) benefits of on-site generation with semiautonomous control.

In previous work, the Berkeley Lab has developed the Distributed Energy Resources Customer Adoption Model (DER-CAM) (Siddiqui et al. 2003 and Stadler et al. 2008). Its optimization techniques find both the combination of equipment and its operation over a typical year that minimize the site's total energy bill, typically for electricity plus natural gas purchases, as well as amortized equipment purchases. Although not used in this work, DER-CAM can also minimize CO_2 emissions, or a combination of cost and CO_2. The chosen equipment and its schedule should be economically attractive to a single site or to members of a microgrid consisting of a cluster of sites.

This report describes recent efforts using DER-CAM to analyze buildings in the California Commercial End-Use Survey (CEUS) database to estimate the potential impact of mid-sized building CHP systems on CO_2 emissions. The application of CHP at large industrial sites is well known, and much of its potential is already being realized (Darrow et al. 2009). Conversely, commercial sector CHP, especially in the mid-size building range (100 kW to 5 MW peak electricity load) is widely overlooked. Only 150 MW of CHP capacity is currently installed in that sector (EEA 2009). Well recognized candidates for CHP installations are hospitals, colleges, and hotels because of the balanced and simultaneous requirements for electricity and heat for hot water, space heating, and cooling. But, other buildings, such as large office structures, can also favor CHP, often with absorption chillers that use waste heat for cooling (Stadler et al. 2009 and Marnay et al. 2008). Based on the CEUS database, which contains 2790 premises, the role of distributed generation (DG) and CHP in greenhouse gas (GHG) abatement is determined. Since it is computationally expensive to solve multiple buildings, 138 representative CA sites[1] in different climate zones were picked. Together, these sample buildings represent roughly 35% of CA commercial electricity demand. Simulating these selected buildings requires a total DER-CAM run time of less than 12 hours, which allowed for multiple sensitivities. For this research, more than 25 sensitivity runs[2] with different technology costs, tariffs, interest rates, incentive

[1] Hospitals, colleges, schools, restaurants, warehouses, retail stores, groceries, offices, and hotels in different sizes.

[2] This number also includes calibration runs. Appendix D shows the final results for the commercial sector in 2020.

levels, etc. have been performed. The Global Warming Solutions Act of 2006 (AB-32) designates the California Air Resources Board (CARB) to be the lead implementing agency. CARB has prepared a scoping plan for achieving reductions in GHG emissions (see also CARB 2009), which considers CHP as an important option. Consequently, the major results reported here are relative to CARB's goal of 4 MW of statewide incremental installed CHP capacity in 2020.

2.0 The Distributed Energy Resources – Customer Adoption Model (DER-CAM)

DER-CAM (Stadler et al. 2008) is a mixed-integer linear program (MILP) written and executed in the General Algebraic Modeling System (GAMS). Its objective is to minimize the annual costs or CO_2 emissions for providing energy services to the modeled site, including utility electricity and natural gas purchases, plus amortized capital and maintenance costs for any distributed generation (DG) investments. The approach is fully technology-neutral and can include energy purchases, on-site conversion, both electrical and thermal on-site renewable harvesting, and end-use efficiency investments[3]. Furthermore, this approach considers the simultaneity of the building cooling problem; that is, results reflect the benefit of electricity demand displacement by heat-activated cooling, which lowers building peak load and, therefore, the on-site generation requirement. Site-specific inputs to the model are end-use energy loads,[4] detailed electricity and natural gas tariffs, and DG investment options. The following supply technologies are currently considered in the DER-CAM model:

- natural gas-fired reciprocating engines, gas turbines, microturbines, and fuel cells;
- photovoltaics (PV) and solar thermal collectors;
- conventional batteries, flow batteries, and heat storage;
- heat exchangers for application of solar thermal and recovered heat to end-use load;
- direct-fired natural gas chillers; and
- heat-driven absorption chillers.

Figure 1 shows a high-level schematic of the building energy flows modeled in DER-CAM. Available energy inputs to the site are solar radiation, utility electricity, utility natural gas, biofuels, and geothermal heat. For a given site, DER-CAM selects the economically or environmental optimal combination of utility electricity purchase, on-site generation, storage and cooling equipment required to meet the site's end-use loads at each time step. The end-uses are as follows:

- electricity-only loads, e.g. lighting and office equipment;

[3] End-use efficiency is not considered in this work (see also Stadler 2009b).

[4] Three different day-long profiles are used to represent the set of daily profiles for each month: weekday, peak day, and weekend day. DER-CAM assumes that three weekdays of each month are peak days.

- cooling loads that can be met either by electricity powered compression or by heat activated absorption cooling, direct-fired natural gas chillers, waste heat or solar heat;
- refrigeration loads that can be met either by standard equipment or absorption equivalents;
- hot-water and space-heating loads that can be met by recovered heat or by natural gas;
- natural gas-only loads, e.g. primarily cooking that can be met only by natural gas.

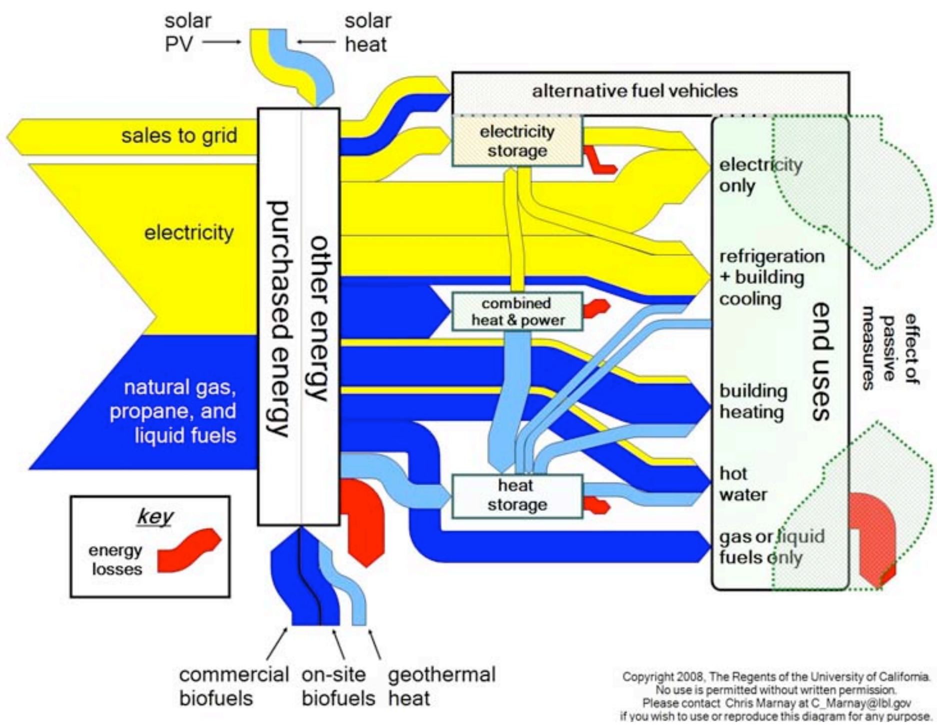

Figure 1. Schematic of Energy Flows Represented in DER-CAM

The outputs of DER-CAM include the optimal DG/storage adoption and an hourly operating schedule, as well as the resulting costs, fuel consumption, and CO_2 emissions (Figure 2).

Optimal combinations of equipment involving PV, thermal generation with heat recovery, thermal heat collection, and heat-activated cooling can be identified in a way that would be intractable by trial-and-error enumeration of possible combinations. The economics of storage are particularly complex, both because they require optimization across multiple time steps and because of the influence of complex tariff structures featuring fixed charges, on-peak, off-peak, and shoulder energy prices, and demand or power charges. Note that facilities with on-site generation will incur electricity bills more biased toward fixed and demand charges and less toward energy charges, thereby making the timing and control of chargeable peaks of particular operational importance.

One major feature not applied in this work is the efficiency investment and demand response module. As can be seen from Figure 1, the end-uses can be directly influenced by efficiency measures and demand reduction measures. Batteries or other storage can act as load shifting devices, another technology choice that can be investigated with DER-CAM. For more information on this module see Stadler 2009b.

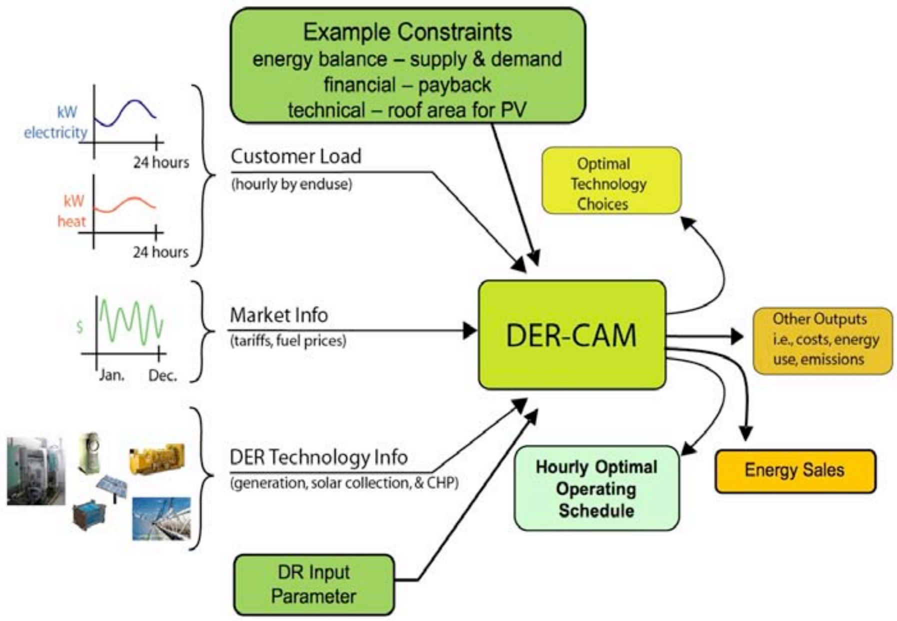

Figure 2. Schematic of Information Flow in DER-CAM

The MILP solved by DER-CAM is shown in pseudocode in Figure 3. In minimizing the site's objective function, DER-CAM also has to take into account various constraints. Among these, the most fundamental ones are the energy-balance and operational constraints, which require that every end-use load has to be met and that the thermodynamics of energy production and transfer are obeyed. The storage constraints are essentially inventory balance constraints that state that the amount of energy in a storage device at the beginning of a time period is equal to the amount available at the beginning of the previous time period plus any energy charged minus any energy discharge minus losses. Finally, investment and regulatory constraints may be included as needed. A limit on the acceptable simple payback period is imposed to mimic typical investment decisions made in practice. Only investment options with a payback period less than 12 years are considered acceptable in this study. For a complete mathematical formulation of the MILP with energy storage solved by DER-CAM, please refer to Stadler et al. 2008.

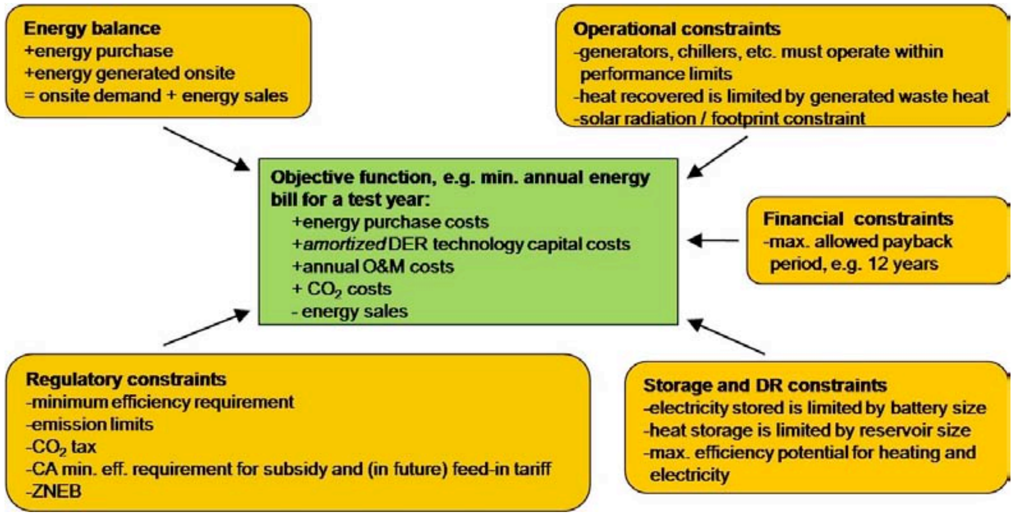

Figure 3. MILP Solved by DER-CAM[5]

3.0 Data Sources

The starting point for the load profiles used within DER-CAM is the California Commercial End-Use Survey (CEUS) database which contains 2790 premises in total. As can been seen from Figure 4, not all utilities participated in CEUS, the most notable absence being the Los Angeles Department of Water and Power (LADWP) and FZ14+15. For this study, the small zones FZ2 and 6 were also excluded, and we also eliminated the miscellaneous building types for which there is insufficient information for simulation. The remaining solid red slices of the pie represent 68% of the total commercial electric demand. Because the focus here is on mid-sized buildings almost half of the red slices were also eliminated, leaving 35% of the total commercial electric demand in the service territories of Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego and Gas Electric (SDG&E) (see CEUS database at http://capabilities.itron.com/ceusweb/).

The menu of available equipment options, their cost and performance characteristics, and example applicable SDG&E tariffs for this DER-CAM analysis are shown in Table 1, Table 2, Table 3, and Table 4. Technology options in DER-CAM are categorized as either continuously or discretely sized. This distinction is important to the economics of DER because some equipment is subject to strong diseconomies of small scale. Continuously sized technologies are available in such a large variety of sizes that it can be assumed that close to optimal capacity could be implemented, e.g. batteries. The installation cost functions for these technologies are assumed to consist of an unavoidable cost (intercept) independent of installed capacity that represents the fixed cost of the infrastructure required to adopt such a device, plus a variable cost proportional to capacity. Discrete technologies must be chosen in exact integer numbers with costs and performance exactly reflecting a specific technology. Please note that both continuous and discrete technologies exhibit economies of scale, but the discrete ones can be more complex and dramatic. Since this particular study focuses on CHP, it is clearly critical that CHP generators

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[5] Not all constraints are shown, e.g. flow batteries have more constraints than simple electric storage.

are represented as discrete technologies, but batteries not so. A half of a 100 kW engine makes no sense, and therefore, finding the integer choice of gensets that minimizes costs is important. Lead-acid batteries on the other hand, are relatively small and are available in many sizes, so assuming that the exact optimal capacity can be deployed does not detract much from the accuracy of the solution. Please consider Figure 5. The left panel shows a discrete technology with three available sizes, k1, k2, and k3 kW. The cost of larger units is greater but costs per kW decline, as shown by the slopes of the rays to the origin. The right panel shows a continuous technology which can be chosen at any capacity. Nonetheless, note that with an intercept and a constant slope, the costs as shown by the rays to the origin do decline in large sizes.

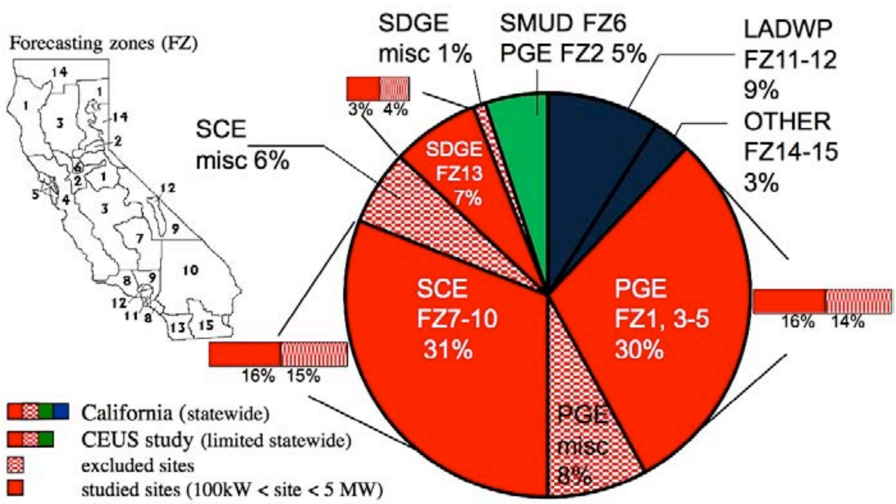

Figure 4. Commercial Electric Demand Fractions

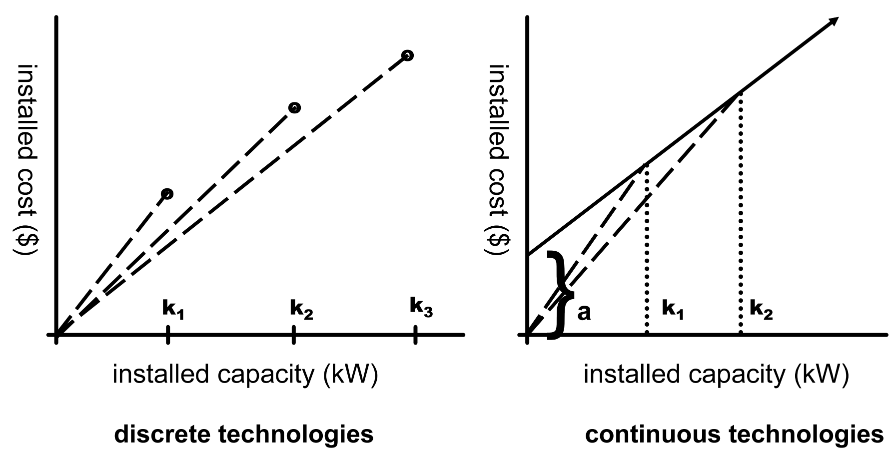

Figure 5. Discrete versus Continuous Technologies

Table 1. Menu of Available Equipment Options in 2020, Continuous Investments[6]

	thermal storage	lead acid batteries	absorption chiller	solar thermal	photo-voltaics
intercept costs (US$)	10000	295	93912	0	3851
variable costs (US$/kW or US$/kWh)	100 US$/kWh	193 US$/kWh	685 US$/kW[7]	500 US$/kW	3237 US$/kW
lifetime (a)	17	5	20	15	20

Sources: Firestone 2004, EPRI-DOE Handbook 2003, Mechanical Cost Data 2008, SGIP 2008, Stevens and Corey 1996, Symons and Butler 2001, Electricity Storage Association, own calculations

Table 2. Menu of Available Equipment Options in 2020, Discrete Investments[8]

	capacity (kW)	installed costs (US$/kW)	installed costs with heat recovery (US$/kW)	Variable maintenance (US$/kWh)	electric efficiency [9] (%), (HHV)	lifetime (a)
ICEsmall	60	2721	na	0.02	0.29	20
ICE-med	250	1482		0.01	0.30	20
GT	1000	1883		0.01	0.22	20
MT-small	60	2116		0.02	0.25	10
MT-med	150	1723		0.02	0.26	10
FC-small	100	2382		0.03	0.36	10
FC-med	250	1909		0.03	0.36	10
ICE-HX-small	60	na	3580	0.02	0.29	20
ICE-HX-med	250		2180	0.01	0.30	20
GT-HX	1000		2580	0.01	0.22	20
MT-HX-small	60		2377	0.02	0.25	10
MT-HX-med	150		1936	0.02	0.26	10
FC-HX-small	100		2770	0.03	0.36	10
FC-HX-med	250		2220	0.03	0.36	10
MT-HX-small-wSGIP[10]	60		2217	0.02	0.25	10
MT-HX-med-wSGIP	150		1776	0.02	0.26	10
FC-HX-small-wSGIP	100		2270	0.03	0.36	10
FC-HX-med-wSGIP	250		1720	0.03	0.36	10

Sources: Goldstein et al. 2003, Firestone 2004, SGIP 2008, own calculations

[6] All cost data in this project are expressed in 2008 US$.

[7] In kW electricity of an equivalent electric chiller.

[8] ICE: Internal combustion engine, GT: Gas turbine, MT: Microturbine, FC: Fuel cell, HX: Heat exchanger. Technologies with HX can utilize waste heat for heating or cooling purposes.

[9] Please note that the California macrogrid efficiency is assumed to be 34%.

[10] SGIP: Considers the California self generation incentive program, which is basically a first cost subsidy.

As is typical for Californian utilities, the electricity tariff has a fixed charge plus time-of-use (TOU) pricing for both energy and power (demand) charges. The latter are proportional to the maximum rate of electricity consumption (kW), regardless of the duration or frequency of such consumption over the billing period. Demand charges may be assessed daily, e.g. for some New York DG customers, or monthly (more common) and may be for all hours of the month or assessed only during certain periods, e.g. on, mid, or off peak, or be assessed at the highest monthly hour of peak system-wide consumption.

There are five demand types in DER-CAM applicable to daily or monthly demand charges:

- non-coincident: incurred by the maximum consumption in any hour;
- on-peak: incurred only during on-peak hours;
- mid-peak: incurred only during mid-peak hours;
- off-peak: incurred only during off-peak hours; and
- coincident: based only on the hour of peak systemwide consumption.

The demand charge in $/kW/mo is a significant determinant of technology choice and sizing of DG and electric storage system installations (Stadler et al. 2008).

For the PG&E service territory three different tariffs were used (see PG&E A-1, PG&E A-10, and PG&E E-19):

- electric peak load 0 – 199 kW: flat tariff A-1, no demand charge, seasonal difference between winter and summer months is a factor of 1.45;
- electric peak load 200 kW – 499 kW: TOU tariff A-10, seasonal demand charge; and
- electric peak load 500 kW and above: TOU tariff E-19, seasonal demand charge.

For SCE service territory also three different tariffs were used (see SCE GS-2, SCE TOU-GS-3, SCE TOU-8):

- electric peak load 20 – 200 kW: flat tariff GS-2, seasonal difference between winter and summer months is a factor of 1.1 (energy) and 2.83 (demand charge);
- electric peak load 200 kW – 499 kW: tariff TOU-GS-3, seasonal demand charge; and
- electric peak load 500 kW and above: tariff TOU-8, seasonal demand charge.

Table 3. Applied 2020 SDG&E Commercial Sector Natural Gas Prices

Natural Gas	
0.03	US$/kWh[11]
112.18/11.22[12]	fixed (US$/month)

Source: SDG&E Tariffs and own calculations[13]

Table 4. Applied 2020 SDG&E Commercial Sector Electricity Prices

Electricity	Summer (May – Sep.)		Winter (Oct. – Apr.)	
	electricity (US$/kWh)	demand (US$/kW)	electricity (US$/kWh)	demand (US$/kW)
non-coincident	na	12.80	na	12.80
on-peak	0.13	13.30	0.13	4.72
mid-peak	0.11		0.12	
off-peak	0.08		0.09	
Fixed (US$/month)	232.87/58.22[14]			

summer on-peak: 11:00 – 18:00 during weekdays

summer mid-peak: 06:00 – 11:00 and 18:00 – 22:00 during weekdays

summer off-peak: 22:00 – 06:00 during weekdays and all weekends and holidays

winter on-peak: 17:00 to 20:00 during weekdays

winter mid-peak: 06:00 – 17:00 and 20:00 – 22:00 during weekdays

winter off-peak: 22:00 – 06:00 during weekdays and all weekends and holidays

Please note that standby tariffs are not part of this research. The interested reader can find some sensitivity runs on standby charges at Stadler et al. 2008. It is found that the adopted CHP capacity changes only slightly when standby charges are applied to a nursing home facility in the San Francisco Bay Area. The major difference is that the energy bill goes up because of the standby charges, but the optimal equipment does not change much. With standby charges, CHP is still one of the best options to reduce demand charges by running the units during times with high prices.

Please see Appendix A for the assumed CA 2020 macrogrid marginal CO_2 emission rates. The solar data necessary for PV and solar thermal simulation were gathered from NREL's

[11] 1 kWh = 0.0341 therm.

[12] Customers with a natural gas consumption above 615,302 kWh/month pay $112.18/month. Customers with a natural gas consumption less than 615,302 kWh/month pay $11.22/month.

[13] For most runs the average natural gas price between 2006 and 2008 is used as estimate for 2020, and therefore, this also considers the spike in natural gas prices in 2008. Please see also Appendix C + D.

[14] Customers with an electric peak load above 500 kW pay $232.87/month. Customers with a peak less than 500 kW pay $58.22/month.

PVWATTS database. Appendix C shows the different tariffs for the three service territories used in this study.

4.0 Major 2020 Results

Using data and assumptions described in the previous section, this study estimates that the mid-sized commercial building sector can economically install 1.4 GW[15] of CHP capacity towards the 4 GW CARB goal. Coincidentally, medium-sized buildings with roughly 35% of the total commercial electric demand contribute a similar amount to the 4 GW goal. However, the CARB study assumes a high fixed capacity factor of 86%, which results in a 30 TWh/a goal[16]. By using DER-CAM, which calculates capacity factors endogenously, the estimated average capacity factor is only approximately 60%. This lower capacity factor results in a lower electricity contribution, just 24%, towards the CARB estimated CHP contribution of 7.2 TWh/a. Finally, because of the lower capacity factors and assumed macrogrid CO_2 emissions in 2020 (see appendix A), the CO_2 reduction potential is just 19% of the goal. However, because only economic adoption occurs under strictly cost minimizing optimization, the sample buildings can reduce their annual energy bill, which includes amortized investment costs, by $190M/a. Also, the results indicate that internal combustion engines (ICEs) with heat exchangers (HXs) are a strongly dominant technology even in 2020. Please note that these calculations also consider solar thermal and photovoltaics (PV), but they are less likely to be installed than ICEs. In this case, 183 MW of PV and 416 MW of solar thermal are adopted and contribute to the CO_2 number reported in Figure 6. Also, no storage systems are adopted since their costs are prohibitive.

These results demonstrate that a high fixed assumed capacity factor results in overly optimistic CO_2 abatement estimates because they do not capture the economics of a microgrid, including the possibility of curtailing engines when they are not economically attractive to operate or when they are in competition with PV and/or solar thermal during the day.

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[15] Installed CHP capacity in midsized buildings with electric peak loads between 100 kW and 5 MW was roughly 150 MW in 2008. Source: EEA 2009 and LBNL calculations.

[16] TWh/a are equivalent to billions of kWh per year.

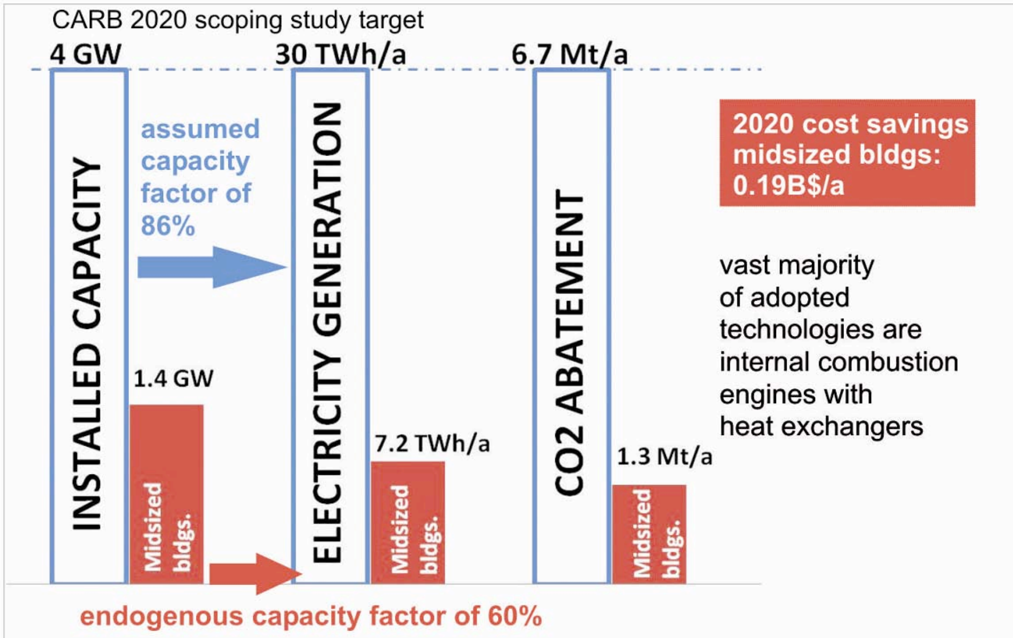

Figure 6. Mid-sized Commercial Building Contribution to the CARB 2020 Goal, Reference Case[17]

The impact of a CHP only feed-in tariff (FiT) is shown by the results of a second scenario presented by the green bars in Figure 7. Assuming a FiT that allows sales back to the macrogrid of CHP generated power at a price slightly below the purchase price (pure net-metering) and without the Self Generation Incentive Program (SGIP), which is basically an investment cost buy down, the FiT has only a moderate impact on installed CHP capacity. The majority of adopted CHP systems are also ICEs with HXs and the FiT does not effectively favor fuel cells. The opportunity of selling into the macrogrid should favor more efficient generating technologies such as fuel cells, but in this case, it is not enough to incent more deployment. As can be seen from Figure 7, the FiT increases the energy production from CHP systems compared to the reference case from Figure 6, 8 TWh/a compared to 7.2 TWh/a, and yet carbon abatement is lower, 1 Mt/a compared to 1.3 Mt/a.

A third scenario, Figure 7 red bars, was performed in which solar thermal and PV are included. In this case, solar contributes to higher total DG energy output, although CHP is slightly reduced to 7.5 TWh/a. In this case, 423 MW of PV and 329 MW of solar thermal are adopted, which is reflected in the improved CO_2 result of Figure 7 (red bars).

[17] For more details on the reference case please see Appendix D, Table D7 run M, as well as Table D12.

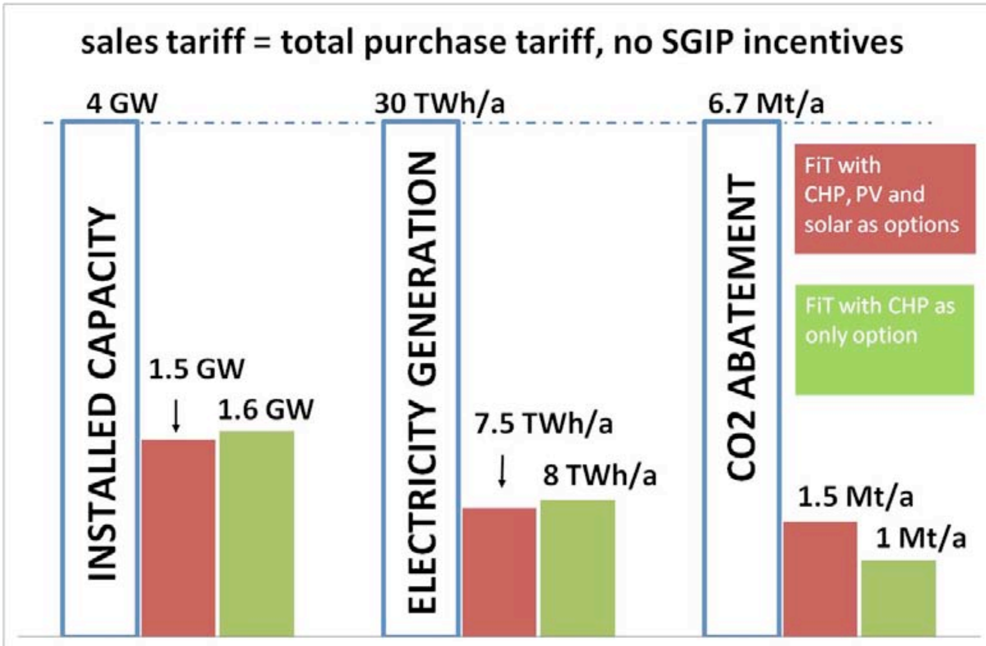

Figure 7. Mid-sized Commercial Building Contribution to the CARB 2020 Goal, Using a Feed-in Tariff Equal to the Purchase Tariff[18]

The reason for the limited CO_2 emission reduction potential is that ICEs have a low conversion efficiency of roughly 30%, which is even lower than the macrogrid efficiency of 34%, and natural gas is the marginal fuel on both sides of the meter. Increasing the electricity production due to electric sales without increasing the opportunity to utilize all the waste heat just reduces the overall energy efficiency. The higher the FiT, the more DG sites will act as power plants with low efficiency. To achieve significant CO_2 emission reductions in this circumstance, it is necessary to use CHP technologies with a higher electric efficiency or add an efficiency or power limit.

A fourth scenario, considers the impact of a high investment subsidy of $1500/kW[19] for fuel cells (FCs), which operate with an electric efficiency above the macrogrid efficiency. Results are shown in Figure 8. It is assumed that to qualify for the $1500/kW SGIP subsidy, the FCs must operate with a minimum total annual efficiency of 60%. This combination has a tremendous impact on CHP adoption as well as CO_2 reduction potential. Almost 73% of the 4 MW CARB goal is achieved by mid-sized commercial buildings alone. Also, electricity production from CHP systems soars to 10.3 TWh/a. Due to the usage of more efficient FCs and the annual efficiency constraint, this sensitivity run delivers the highest CO_2 reduction potential for CA. Also note that, although not explicitly shown in Figure 8, the installed PV capacity and solar

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[18] For more details on the FiT runs please refer to Appendix D, Table D10 run M-FiT and Table D11 run M-FiT noPVSolar.

[19] Note however that this $1500/kW future case represents a lower incentive than the current California SGIP support levels for stationary fuel cells of $2500/kW for natural gas fueled units and $4500/kW for renewable fueled units.

thermal capacities are reduced to 95 MW and 247 MW, respectively, compared to 423 MW and 329 MW in the 3rd scenario from Figure 7.

Does this competition between FCs and PV/solar thermal change if natural gas is made more expensive by a CO_2 pricing scheme? Figure 9 shows the CO_2 reduction compared to a do-nothing case without any investments in DG. With CHP, PV, and solar thermal as possible options, the CO_2 reduction increases rapidly, but shows a saturation at high CO_2 prices, partly due to limited space for PV and solar thermal in commercial buildings[20]. However, most interesting is the fact that CHP adoption also increases with increasing CO_2 prices (see red line in Figure 9). Although not shown in Figure 9, detailed analyses show that with increasing CO_2 prices more and more ICEs are replaced by efficient FCs. Also, since CHP is an efficiency measure the adopted capacity also increases and can reach overall efficiency levels of 80%. Note however, the very high carbon costs that are covered in Figure 9, all the way up to 400-500 $/$tCO_2$.[21]

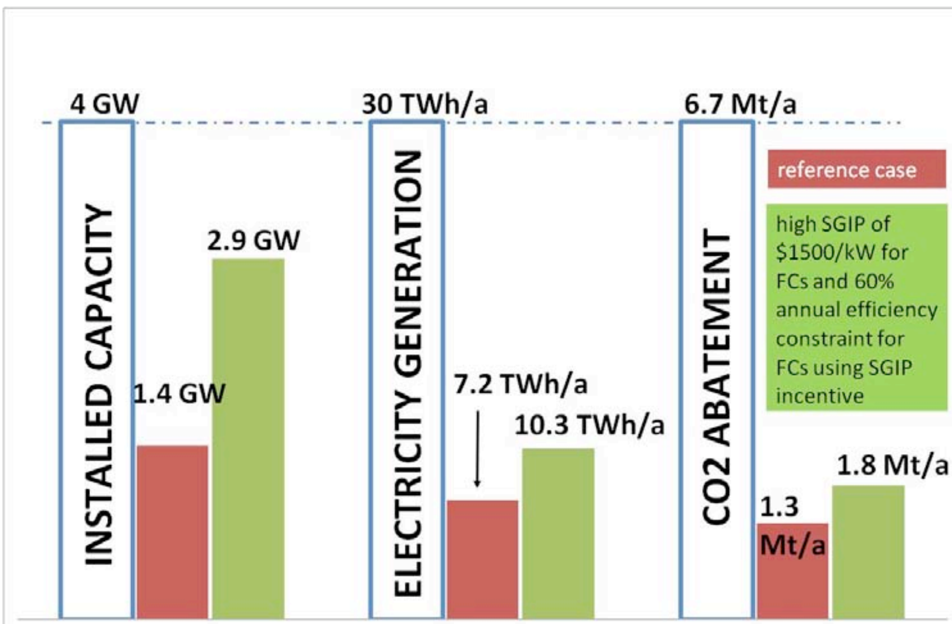

Figure 8. Mid-sized Commercial Building Contribution to the CARB 2020 Goal, with a $1500/kW SGIP Support Level for Stationary Fuel Cell Systems[22]

[20] The PV and solar thermal area constraint within DER-CAM and the used data for this study are subject to further research.

[21] "tCO_2" is equivalent to a metric ton of CO_2.

[22] For more details on this scenario please refer to Appendix D, Table D11 run M-SGIP60% and Table D13.

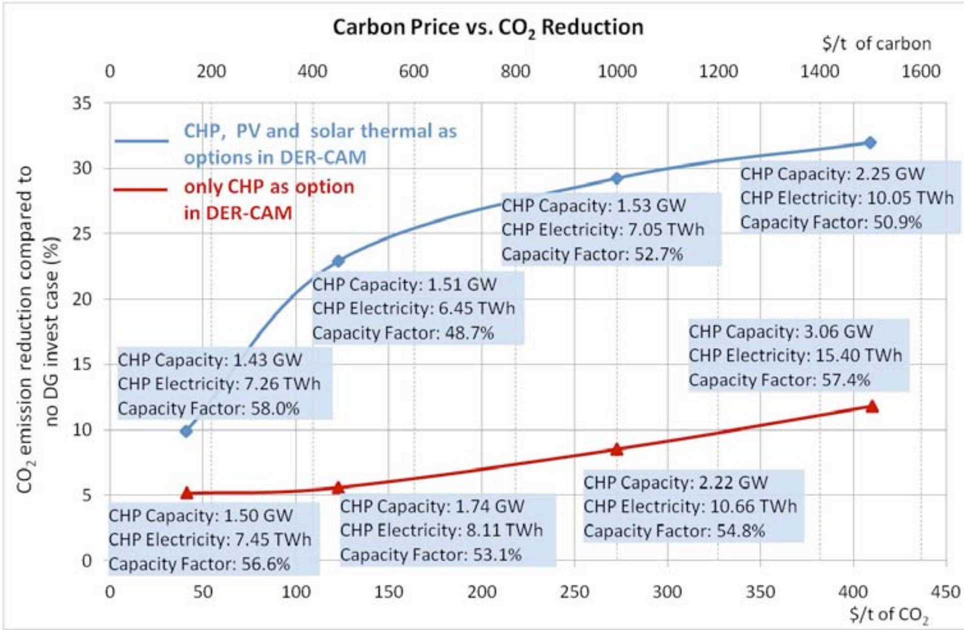

Figure 9. Influence of a CO_2 Pricing Scheme[23]

A more detailed analysis of the reference case[24] that adopts 1.4 GW of CHP capacities in 2020 can be found in Figure 10 and Figure 11. The figures show the attractive physical and economic climate for CHP systems in the SDG&E service territory. In fact, the analysis predicts that 36% of potential CHP capacity is added in SDG&E's FZ 13. The northern California zone PG&E FZ 01, as well as southern California zone SCE FZ 07 play only a marginal role in new CHP adoption. However, despite the fact that PG&E FZ 03 only adopts 25.8 MW of CHP by 2020, it delivers an impressive CHP capacity factor of 75% followed by PG&E FZ 04 and SDG&E FZ 13 (see also Figure 12). Note that capacity utilization varies considerably by climate zone, and in general, the higher capacity factors are achieved in the hotter areas. The only coastal area that is attractive is San Diego, which is located in a favorable climate zone.

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[23] For more details on these runs please refer to Appendix D, Table D9, run M-lowCtax, run M-lowCtax-noPVSolar, and run M-medCtax as well as Table D10, run M-medCtaxnoPVSolar, run M-highCtax, and run M-highCtaxnoPVSolar.

[24] Please see also Appendix D, Table D7 run M, as well as Table D12.

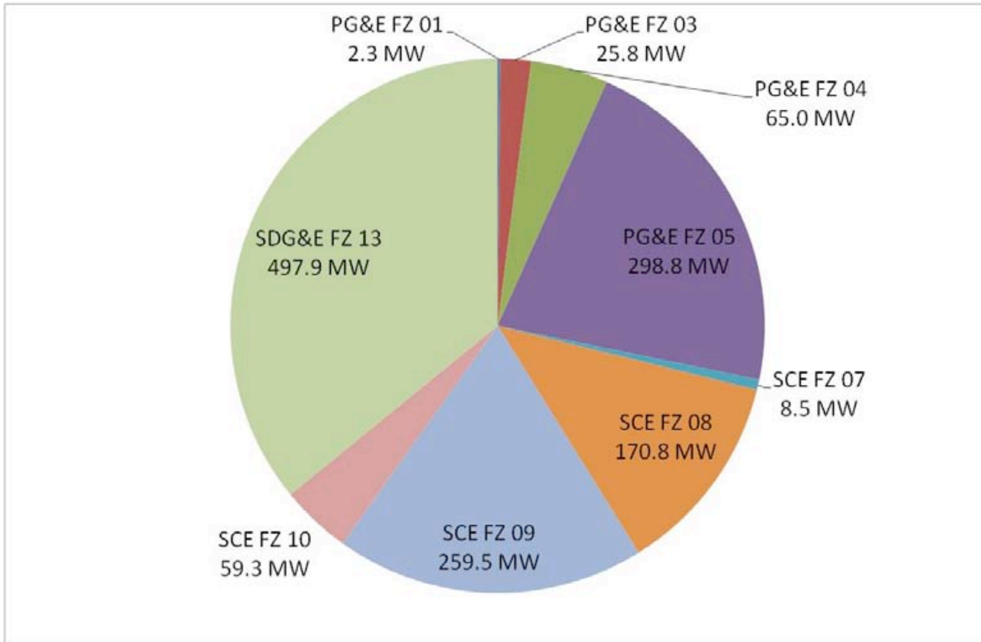

Figure 10. Adopted CHP Capacities by Forecasting Zones (FZs), Reference Case

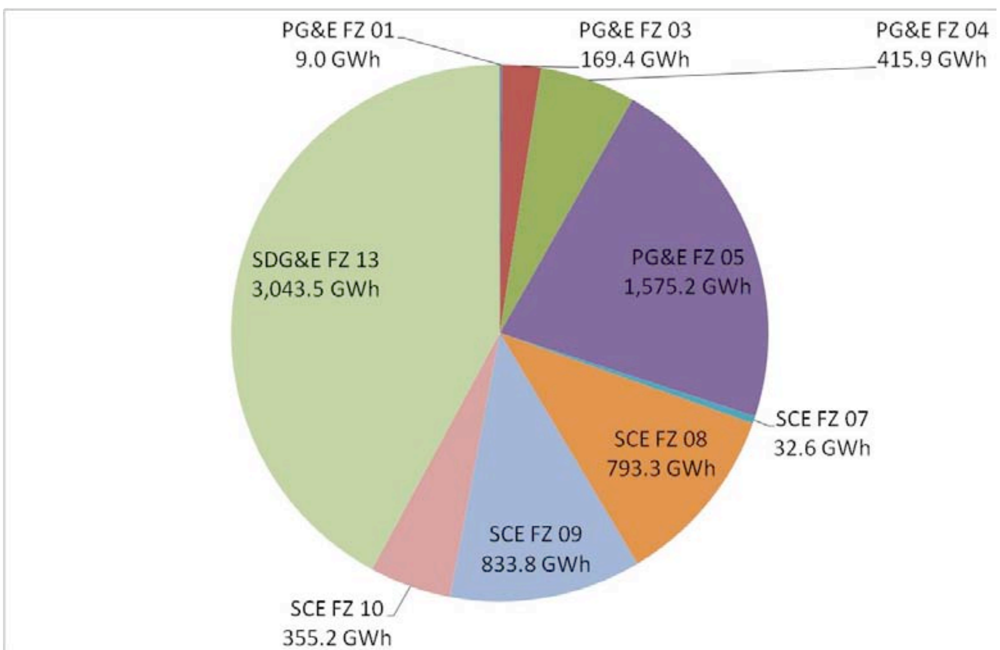

Figure 11. Electricity Generation from CHP by Forecasting Zones (FZs), Reference Case

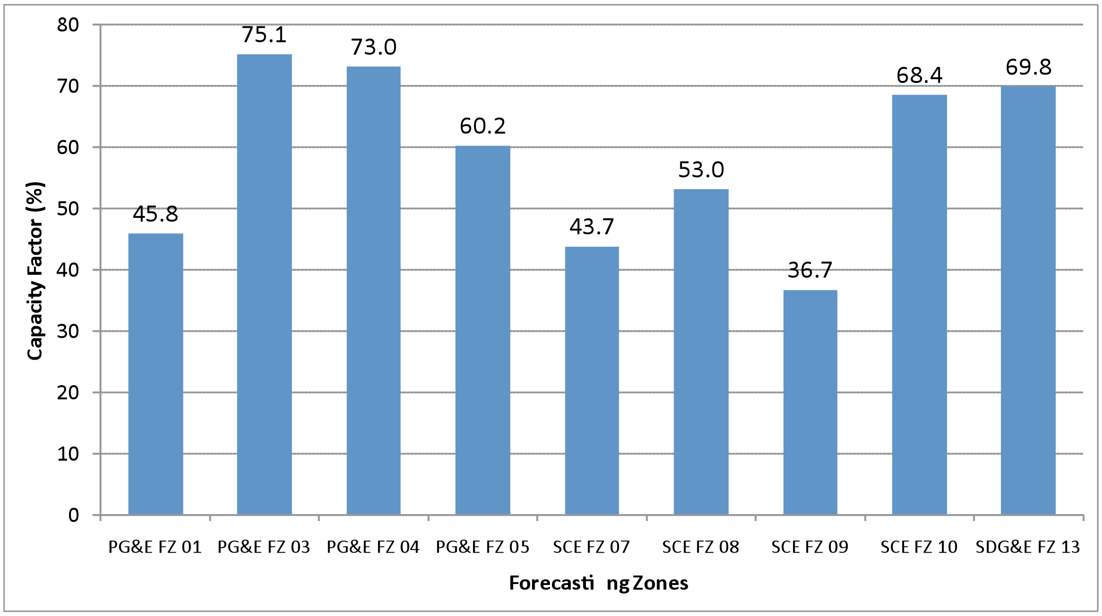

Figure 12. Capacity Factors for CHP by Forecasting Zones (FZs), Reference Case

Figure 13 and Figure 14 again show the importance of the SDG&E service territory. In the reference case SDG&E customers[25] can reduce their energy costs by 129 M$ and bring the costs down to 599 M$. This represents a cost reduction of 18% compared to the do-nothing case where all energy needs to be purchased from the utility. Also, in terms of relative CO_2 reduction SDG&E leads with a yearly reduction of 350 Mt, which represents a 13.4% CO_2 reduction compared to the do-nothing case. SCE is the least attractive utility territory for CHP adoption and based on that it contributes the least to the CARB 2020 CO_2 goal. However, in absolute terms the highest CO_2 reduction of 616 Mt/a can be achieved in PG&E service territory.

In Figure 15 and Figure 16 we show building type based results. Figure 15, depicts the adopted CHP capacity for every major building type in this study for the reference case that adopts 1.4 GW of CHP in 2020. Large offices (LOFF) are favorable for CHP adoption and 44% of the 1.4 GW are installed in them. They are followed by health care (HLTH) facilities, which constitute 21%, colleges (COLL) and lodging (LOGD), which together are responsible for 24% of the potential. Small offices (SOFF), warehouses (WRHS), and restaurants (REST) do not appear in the results of this study. Figure 16 shows a very similar result compared to the adopted CHP capacity. Large offices (LOFF) are favorable for CHP adoption and 37% of the 7.2 TWh are generated in them. They are followed by health care (HLTH) facilities, which constitute 26%, colleges (COLL) and lodging (LOGD), which together are responsible for 26% of the generation. Small offices (SOFF), warehouses (WRHS), and restaurants (REST) do not appear in the results of this study.

[25] Buildings with electric loads between 100 kW and 5 MW.

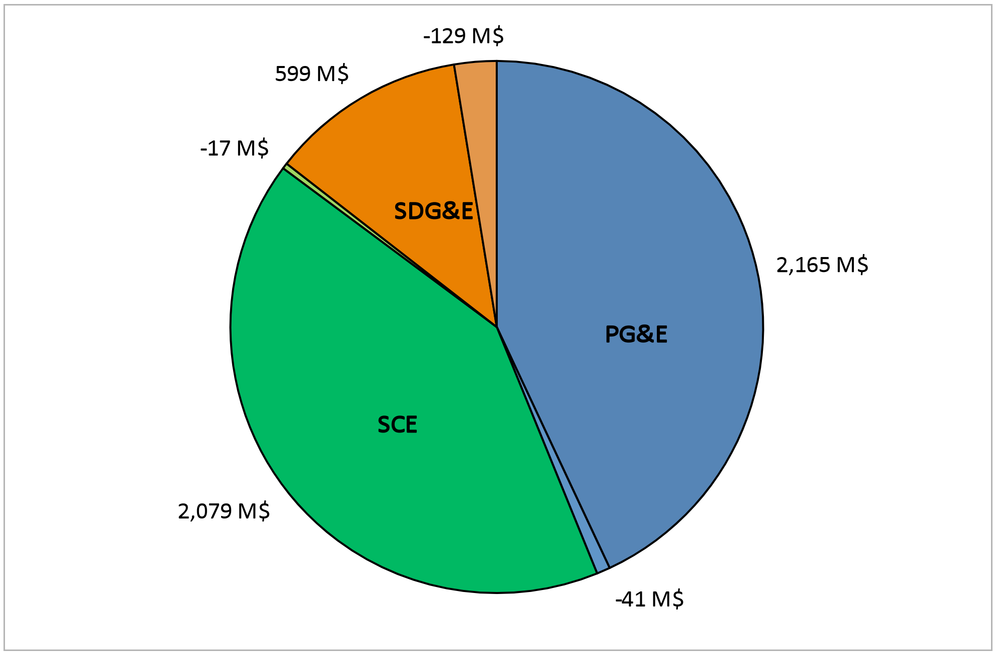

Figure 13. Total Cost Reductions for CHP Adopters for Different Utilities, Reference Case

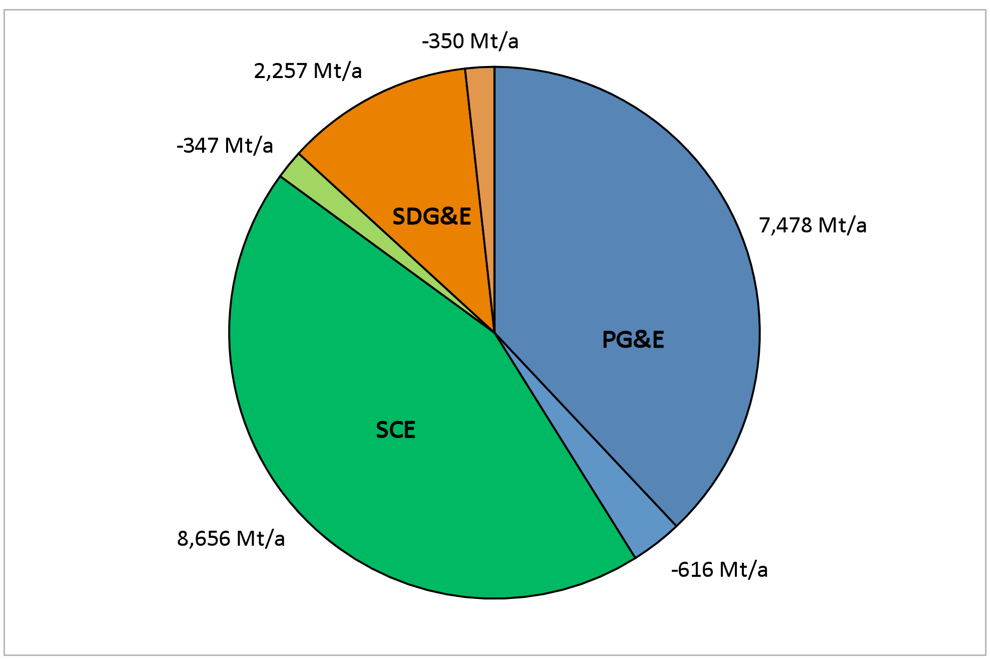

Figure 14. Total CO_2 Reductions for CHP Adopters for Different Utilities, Reference Case

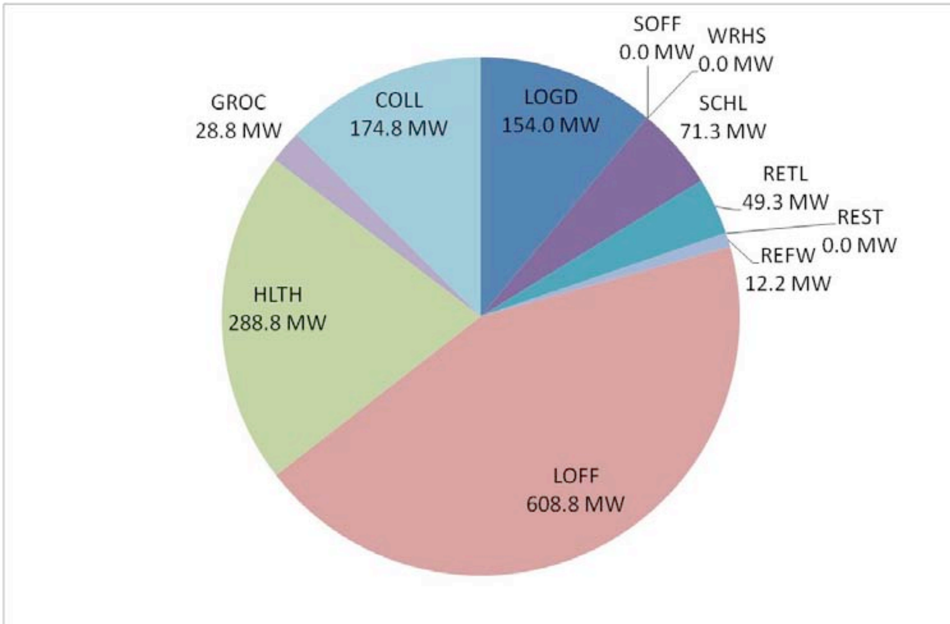

Figure 15. Adopted CHP Capacities by Building Types[26], Reference Case[27]

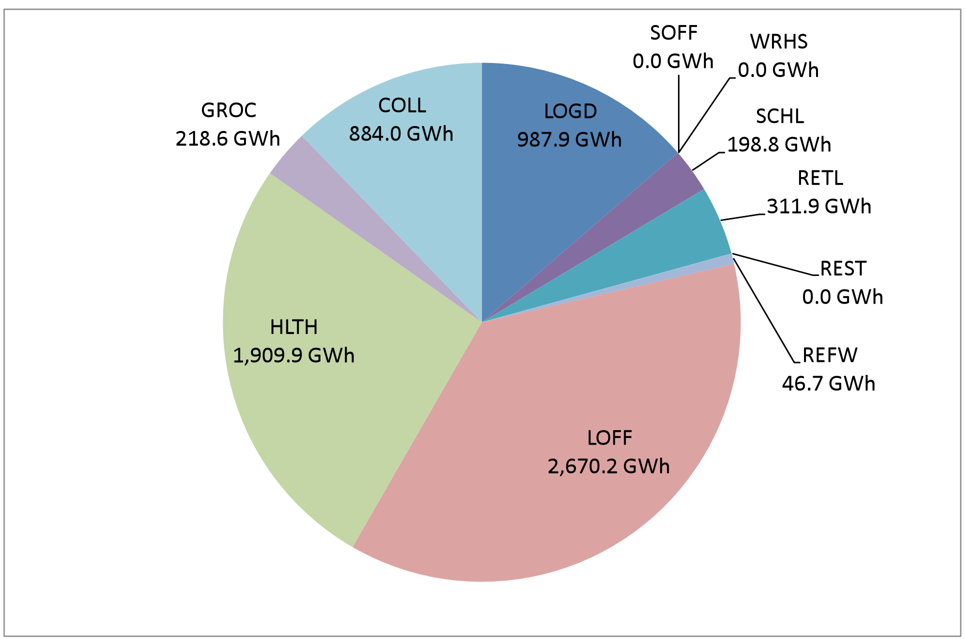

Figure 16. Electricity Generation from CHP by Building Types, Reference Case[28]

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[26] Please note that only one restaurant was considered in this study since mostly the electric peak load is less than 100 kW.

[27] SOFF: Small Office, WRHS: Warehouse, SCHL: School, RETL: Retail Store, REST: Restaurant, REFW: Refrigerated Warehouse, LOFF: Large Office, HLTH: Health Care, GROC: Grocery (Food and Liquor in CEUS), COLL: College, LOGD: Lodging (Hotel plus Motel in CEUS).

Combining the regional results for every utility with the building specific results creates Figure 17 and Figure 18. For Figure 17 the best of every building category, in terms of cost saving, was identified and shows impressively that 9 of the major building categories have their best buildings in FZ 13 (SDG&E). Also, Figure 17 shows the dominance of large office buildings (LOFF). Please note that the "Cost savings" plus the "Costs with DER adoption" from Figure 17 deliver the original energy costs for the do-nothing case where all energy is bought from the local utility. Finally, in Figure 18 the CO_2 abatement for the best buildings are shown and again large office buildings (LOFF) in FZ 13 show the biggest CO_2 reduction potential making it a prime target for CHP adoption. Both Figures show that large offices, health care facilities, colleges, and hotels/motels should be considered as prime candidates for CHP adoption, especially in SDG&E service territory.

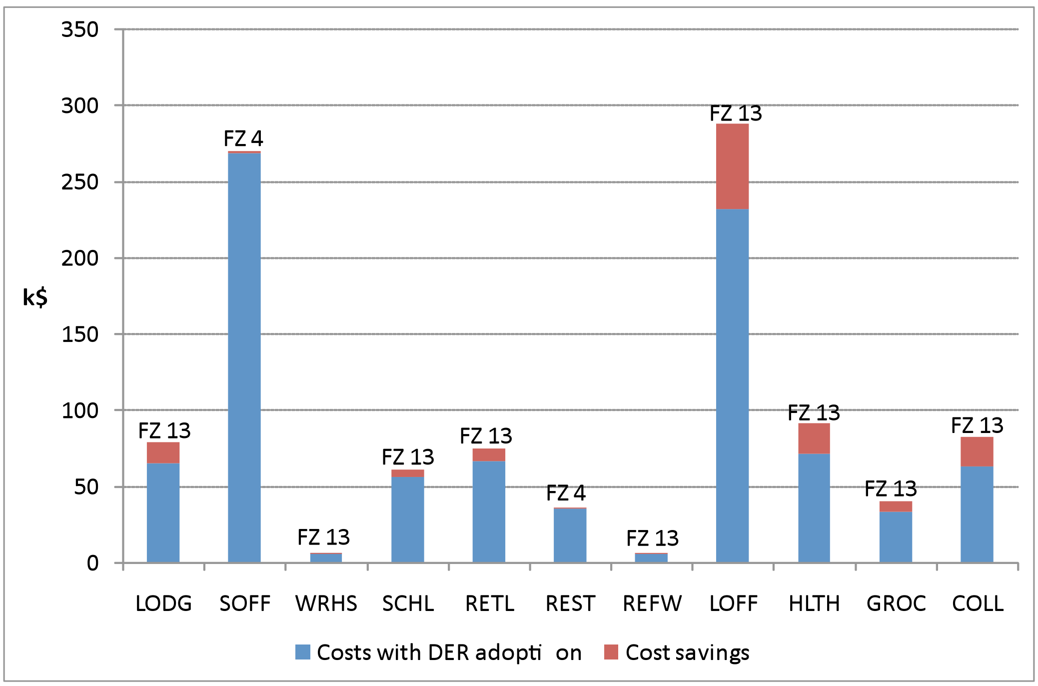

Figure 17. Best Buildings in Terms of Cost Saving and Related Forecasting Climate Zones, Reference Case

[28] SOFF: Small Office, WRHS: Warehouse, SCHL: School, RETL: Retail Store, REST: Restaurant, REFW: Refrigerated Warehouse, LOFF: Large Office, HLTH: Health Care, GROC: Grocery (Food and Liquor in CEUS), COLL: College, LOGD: Lodging (Hotel plus Motel in CEUS).

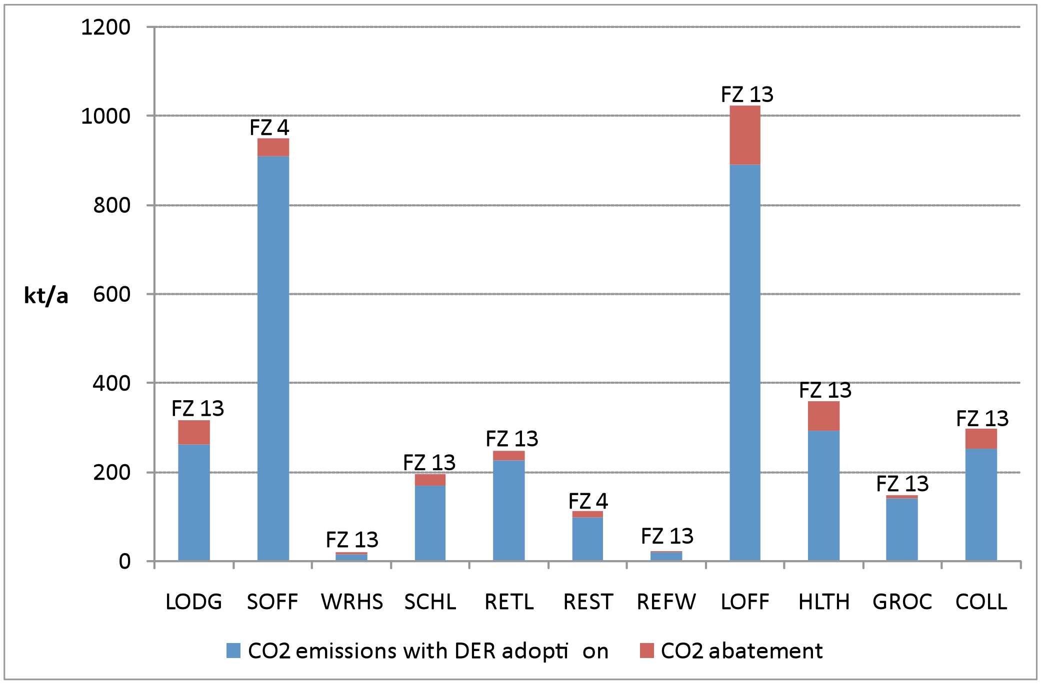

Figure 18. CO_2 Savings for Best Buildings, Reference Case

5.0 Conclusions

This study looks at the potential role of medium-sized commercial building CHP-enabled DG in reducing CA's GHG emissions over the next decade. How DG with CHP might be implemented in cost minimizing microgrids is analyzed by applying an optimization that minimizes example sites' annual energy costs. Using a representative sample of 138 mid-sized commercial buildings taken from CEUS, existing tariffs of three major electricity distribution ultilities plus a natural gas company, and performance data of available technology in 2020, the GHG reduction potential is estimated for a market segment representing about 35% of CA's commercial sector. In a reference case, this segment is estimated to be capable of economically installing 1.4 GW of CHP, 35% of the CARB statewide Scoping Study 4 GW goal. Because CARB's assumed utilization is far higher than is found by the optimization, the adopted CHP only contributes 19% of the target. Several sensitivity runs were completed. One applies a simple feed-in tariff similar to net metering, and another includes a generous self-generation incentive program (SGIP) subsidy for fuel cells. The feed-in tariff proves ineffective at stimulating CHP deployment, while the SGIP buy down is more powerful.

Additional key findings and conclusions include:

- the attractiveness of CHP varies widely by climate zone and service territory, but in general, hotter inland areas and San Diego are the more attractive areas because high cooling loads achieve higher equipment utilization;
- additionally, large office buildings are surprisingly good hosts for CHP, so large office buildings in San Diego and the hotter urban centers in the SCE and PG&E territories emerge as promising hosts worthy of further study;

- overall the effect on CO_2 emissions is limited, never exceeding 27 %[29] of the CARB target, nonetheless, results suggest the CO_2 emissions abatement potential of CHP in mid-sized CA buildings is significant, and much more than is typically assumed; and
- while they played a small role in this study, the potential for CHP in restaurants also merits closer study since they consume a considerable amount of natural gas (see also Appendix B, Figure B4).

Only one restaurant was included among our 138 buildings because of the low electric peak loads, but the sector consumes almost a quarter of state commercial sector natural gas use, so the potential heat sinks are significant. However, because the sector is highly heterogeneous, it would require a more precise and further disaggregated analysis than was possible herein.

Overall we find that the approach of using DER-CAM for building-by-building study of microgrid potential has proven viable. The use of the optimization modeling approach carries the major advantage of permitting analysis of multiple technologies in competition with each other. The computational burden of simulating hundreds of individual buildings is significant but feasible overnight using ordinary laptops, and would be quite manageable on faster platforms. Based on the promising overall findings from this study, further investigation would appear to be warranted to further explore key nuances associated with building types, climate zones, and utility service territories. A wider range of policy instruments should be analyzed, including potential capital cost buy-downs, e.g. SGIP, tax credits, carbon emissions cost internalization, and FiT policy programs.

Note that efficiency and behavioral response may contribute towards meeting future energy services requirements, however, these were not taken into account in this study. Additionally, the area constraint for PV and solar thermal systems needs a more detailed analysis since they vary with climate zone as well as building ownership. Finally, we believe the ownership of buildings and the issue of project decision-making authority needs special attention since it might constitute a major barrier for DG adoption and dampen the DG / CHP potential identified in this study.

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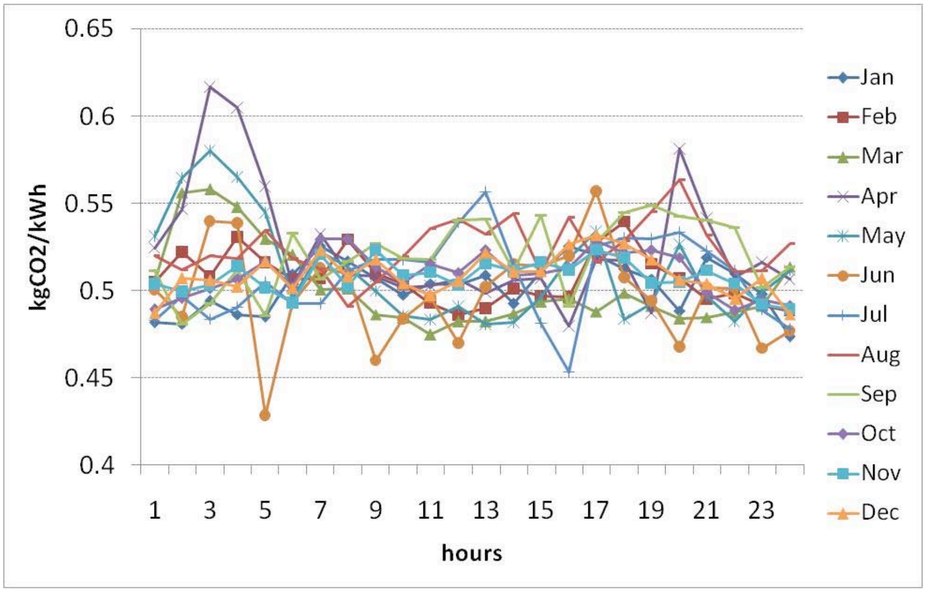
7.0 Appendix A: Hourly Marginal CO_2 Rates



Source: Mahone et al. 2008 and LBNL calculations

Figure A1. Average Hourly Marginal Macrogrid CO_2 Rates in 2020

8.0 Appendix B: CEUS Building Data

The CEUS dataset contains 2790 premises from 4 local service entities (LSEs), energy data collected in year 2000:

- PG&E: 1001 premises
- SMUD: 300 premises
- SCE: 1144 premises
- SDG&E: 345 premises

The 2790 premises are subdivided into

- 12 building types, 4 sizes for each building type as small (S), medium (M), large (L), and Census; the later is not considered in this work
- 13 end-uses (3 HVAC, 10 Non-HVAC); the samples contain simulated hourly estimates of end-use consumption as of electricity and natural gas alone, i.e. no propane
- 12 Forecasting Climate Zones (FZ); using 10 year normalized weather, and the
- data is based on eQUEST simulations

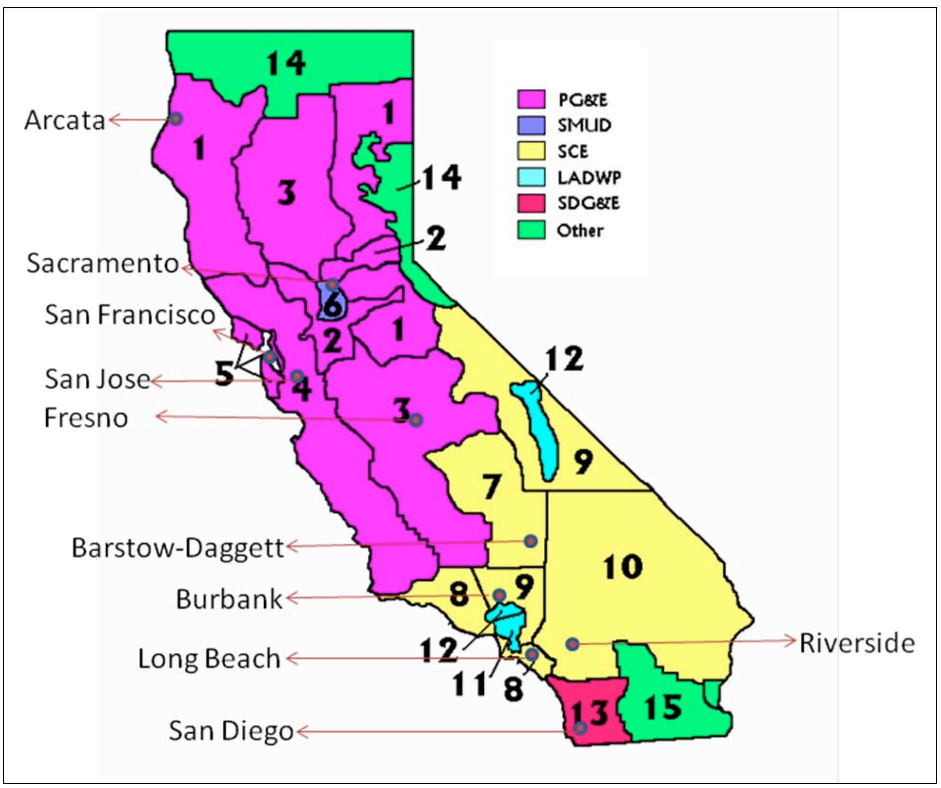


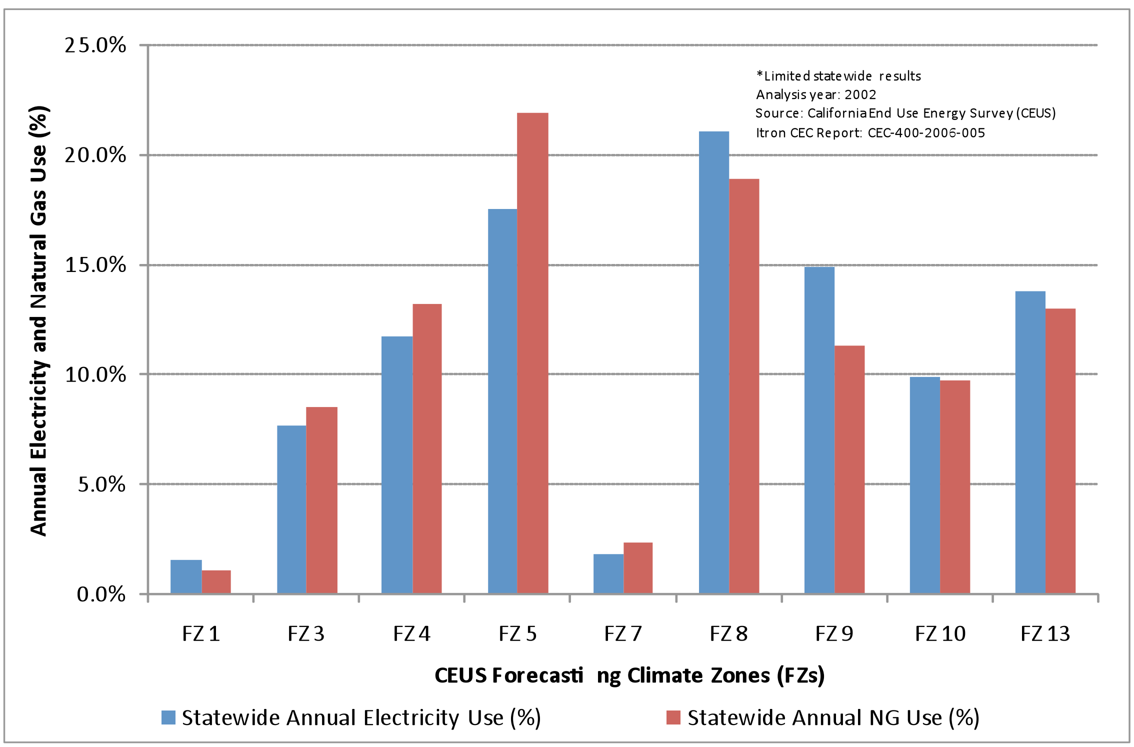
Figure B1. CA Climate Zones, Weather stations, and Utilities

Table B1. Forecasting Climate Zones (FZs) and Utilities

Forecasting Climate Zones (FZ), Red and green FZs are in CEUS database (*statewide* sample), red is covered by this study in principle, black FZs are not covered	Utility
1, 2, 3, 4, 5	PG&E
6	SMUD
7, 8, 9, 10	SCE
11, 12	LADWP
13	SDG&E
14, 15	Other

The *statewide* sample refers to CEUS study area: PG&E, SCE, SDG&E, & SMUD control areas. Note that LADWP as well as FZ 14 and 15 are not covered by CEUS.

The *limited statewide* samples refers to PG&E without FZ 2, SCE, & SDG&E, control areas, and no misc. building types and this constitutes 35% of the total commercial electric demand.

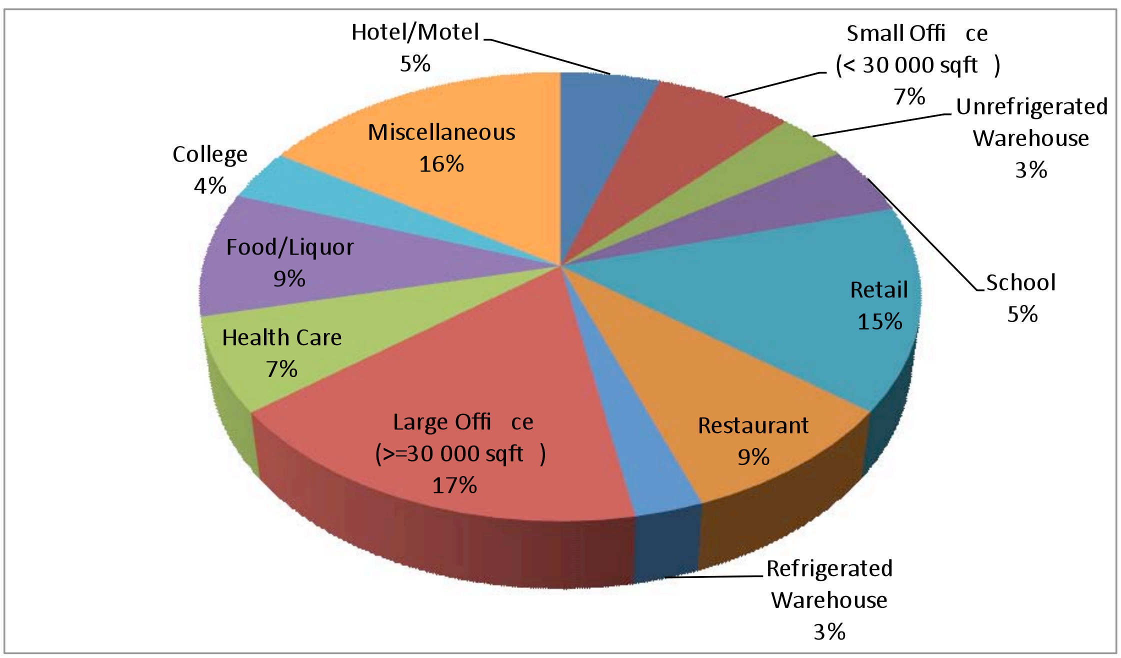


Source: CEUS, Itron CEC Report: CEC-400-2006-005

Figure B2. *Statewide* Annual Electricity and Natural Gas Use for the Forecasting Climate Zones

The 12 commercial building types considered in CEUS are:

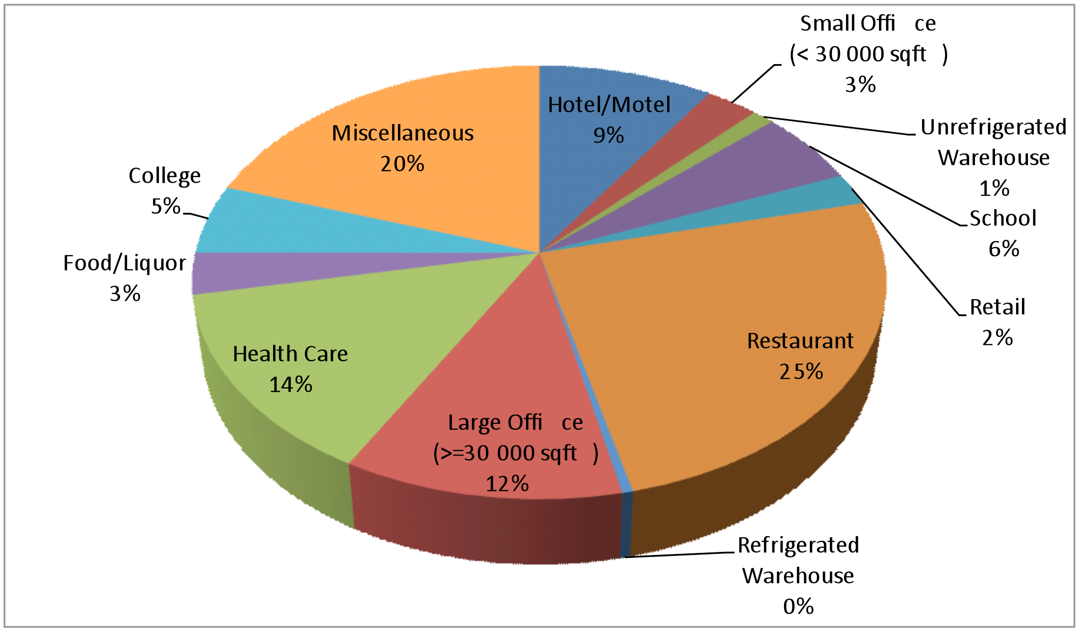
- Small Office (<30 000 sqft)
- Large Office (≥30 000 sqft)
- Restaurant
- Retail
- Food/Liquor
- Unrefrigerated Warehouse
- Refrigerated Warehouse
- School
- College
- Health Care
- Hotel/Motel
- Miscellaneous (not considered in this study)



Source: CEUS and LBNL calculations

Figure B3. Electricity Use by Building Type[30]

[30] The miscellaneous building type is not considered in this study.



Source: CEUS and LBNL calculations

Figure B4. Natural Gas Use by Building Type[31]

138 representative CA sites in different climate zones with an electric peak load between 100 kW and 5 MW were picked. These sample buildings represent roughly 35% of CA commercial electricity demand. Simulating these selected buildings requires a total DER-CAM run time of less than 12 hours, which allowed for multiple sensitivities.

[31] The miscellaneous building type is not considered in this study.

Table B2. Electric Peak Loads for Various Building Types and Climate Zones (Green Cells are Represented in this Study)

		Peak electric load (kW)								
Category	**Size**	**FZ 01**	**FZ 03**	**FZ 04**	**FZ 05**	**FZ 07**	**FZ 08**	**FZ 09**	**FZ 10**	**FZ 13**
Hotel/Motel	S	5.8	39.5	14.0	12.9	9.9	16.9	21.4	29.9	20.5
	M	46.4	278.9	118.1	138.2	87.4	143.9	215.4	252.4	191.8
	L	503.0	1535.4	578.8	835.5	461.2	847.7	1122.4	1387.9	1052.7
Small Office	S	1.4	1.3	5.9	0.7	1.2	1.0	1.3	1.4	0.9
	M	9.8	10.2	41.6	4.9	7.4	7.1	8.1	8.5	5.9
	L	56.9	63.7	242.3	33.0	43.4	48.6	53.8	53.8	37.8
Unref. Warehouse	S	-	0.9	4.0	1.7	-	2.8	5.7	6.1	2.5
	M	-	11.9	44.4	20.0	-	30.2	66.7	68.4	28.5
	L	-	120.2	333.9	198.9	-	331.0	568.4	588.1	235.0
School	S	21.8	18.0	28.0	23.7	23.8	23.5	25.8	25.3	17.2
	M	163.9	128.6	153.8	152.3	148.8	139.9	164.7	186.4	143.0
	L	641.2	614.7	556.6	550.4	597.8	518.7	652.6	760.7	515.8
Retail Store	S	4.1	7.2	5.6	4.3	7.3	5.1	3.9	5.5	4.7
	M	56.3	89.7	63.4	52.8	76.8	56.9	47.9	59.1	53.5
	L	547.1	740.3	494.0	475.7	678.3	501.1	386.4	549.0	505.3
Restaurant	S	8.1	7.4	10.2	8.0	9.1	9.4	9.0	8.0	7.5
	M	33.2	30.2	37.0	31.4	35.1	31.8	32.0	27.2	28.6
	L	76.5	84.5	111.2	93.6	95.1	96.6	92.8	77.9	94.3
Ref. Warehouse	S	56.3	58.6	41.4	47.2	10.5	25.2	73.8	54.1	16.2
	M	973.6	556.5	408.6	462.1	137.1	366.3	953.7	780.3	217.7
	L	-	2484.5	2238.3	2618.6	1030.0	1501.1	4233.1	3066.0	973.2
Large Office	S	128.0	423.3	264.3	372.6	102.0	299.8	1307.4	250.7	376.4
	M	354.8	981.4	665.8	912.7	288.0	731.4	3450.7	639.1	962.8
	L	-	2542.4	1640.3	2359.9	608.5	1708.5	8715.0	1369.6	2516.7
Health Care	S	28.0	14.2	18.2	22.7	31.0	33.7	31.7	31.3	24.5
	M	335.3	170.2	203.1	0.3	403.8	391.5	311.0	371.7	399.3
	L	2027.7	1174.4	1333.1	1891.9	2447.2	2250.8	2251.3	2345.7	2197.3
Food/Liquor	S	8.4	8.8	9.2	8.2	11.7	8.9	9.1	9.7	11.0
	M	67.7	52.5	63.5	64.4	77.8	59.5	70.5	66.0	87.0
	L	291.2	285.2	307.6	291.2	399.0	323.7	352.0	318.1	371.9
College	S	8.1	22.4	15.3	26.5	8.5	19.0	21.6	12.4	33.1
	M	301.5	362.3	480.9	654.4	206.3	505.3	543.2	275.2	730.7
	L	2030.4	2529.5	2420.1	3146.8	762.8	2945.2	3204.6	1937.3	4663.2

Source: CEUS and LBNL calculations

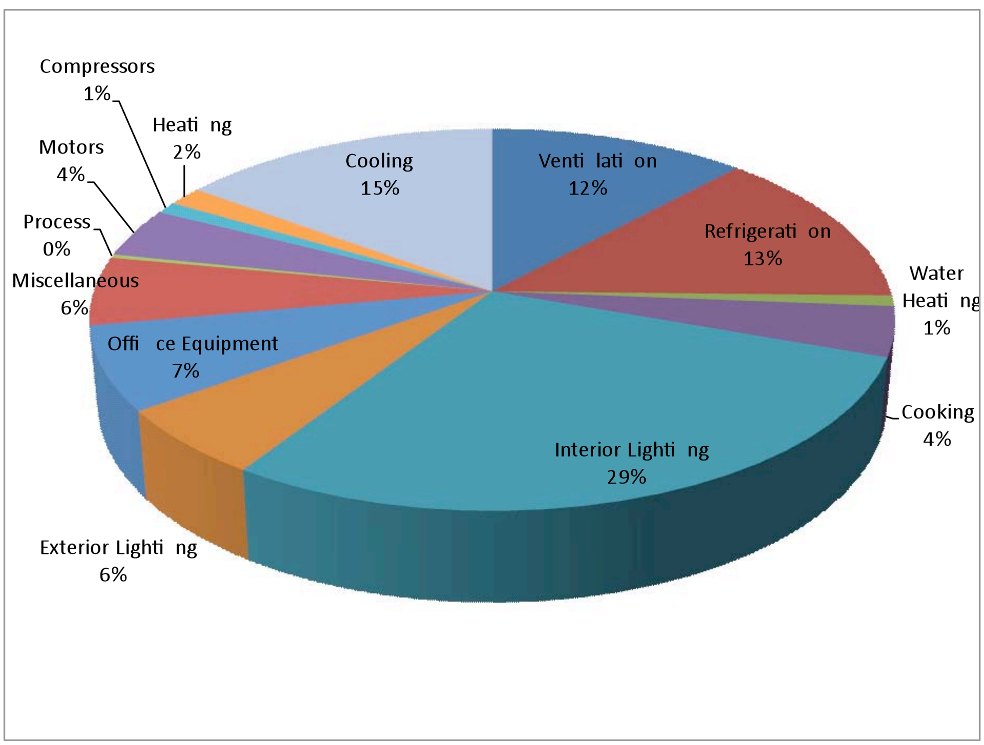
Table B3. CEUS Sample Frame Numbers for every Building Type and FZ

Category	Size	Sample frame numbers								
		FZ 1	FZ 3	FZ 4	FZ 5	FZ 7	FZ 8	FZ 9	FZ 10	FZ 13
Hotel/Motel	S	531	459	922	879	223	642	623	541	649
	M	36	94	179	203	30	234	126	151	170
	L	2	3	17	55	2	60	20	28	40
Small Office	S	3,581	10,506	10,945	15,552	2,178	18,844	14,863	9,182	22,042
	M	1,604	5,386	7,109	9,104	1,515	12,437	9,285	6,947	14,127
	L	223	1,084	1,785	2,780	273	4,139	2,259	1,516	3,135
Unref. Warehouse	S	892	3,653	2,818	5,188	538	5,878	5,347	2,437	4,092
	M	46	416	636	1,071	61	1,167	1,185	515	575
	L	4	39	60	101	1	116	113	71	46
School	S	487	1,194	1,215	1,594	327	1,158	1,102	536	899
	M	69	444	400	354	104	466	561	456	392
	L	6	65	70	54	17	107	115	83	116
Retail Store	S	2,159	5,246	7,308	10,917	1,579	13,337	10,283	6,596	8,866
	M	205	974	1,498	2,084	315	3,134	2,031	1,598	1,709
	L	13	110	187	235	35	406	318	246	197
Restaurant	S	1,019	2,202	3,572	7,030	568	5,153	3,900	1,987	4,123
	M	278	1,051	1,683	2,026	281	3,153	2,346	1,499	1,822
	L	32	348	362	450	89	846	626	458	421
Ref. Warehouse	S	48	187	137	211	37	186	161	61	282
	M	6	89	39	29	7	22	14	10	12
	L	0	14	12	4	3	7	7	6	4
Large Office	S	9	95	302	585	15	713	304	147	331
	M	3	16	139	252	8	266	94	34	109
	L	0	6	55	114	3	107	26	3	51
Health Care	S	201	596	655	1,041	145	774	763	489	865
	M	22	100	100	144	32	153	136	96	128
	L	4	17	31	45	6	32	25	13	19
Food/Liquor	S	574	2,049	2,350	4,148	428	3,059	3,390	1,471	1,963
	M	129	581	521	599	145	631	572	357	554
	L	36	102	173	191	27	289	224	159	115
College	S	67	164	284	392	89	659	661	288	456
	M	6	19	24	55	6	59	36	24	40
	L	1	6	13	12	1	17	13	7	13

Source: CEUS and LBNL calculations

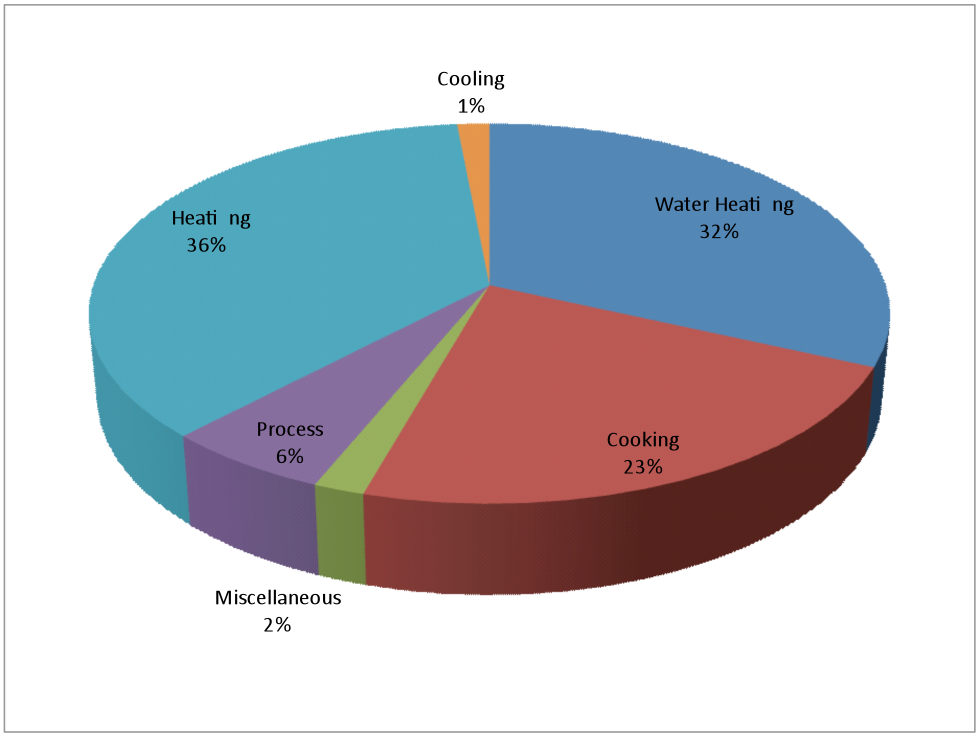
Every building with an electric peak load between 100 kW and 5 MW (green cells from Table B2) is optimized with DER-CAM and the results are inflated to the state level by using the sample frame numbers from Table B3. The following 13 end-uses are considered within CEUS and also within this study:

- 3 HVAC end-uses
    - Space Heating
    - Space Cooling
    - Ventilation
- 10 Non-HVAC end-uses
    - Water Heating
    - Cooking
    - Refrigeration
    - Interior Lighting
    - Exterior Lighting
    - Office Equipment
    - Miscellaneous Equipment
    - Air Compressors
    - Motors (non-HVAC)
    - Process Equipment



Source: CEUS and LBNL calculations

Figure B5. Electricity Consumption by End-Use



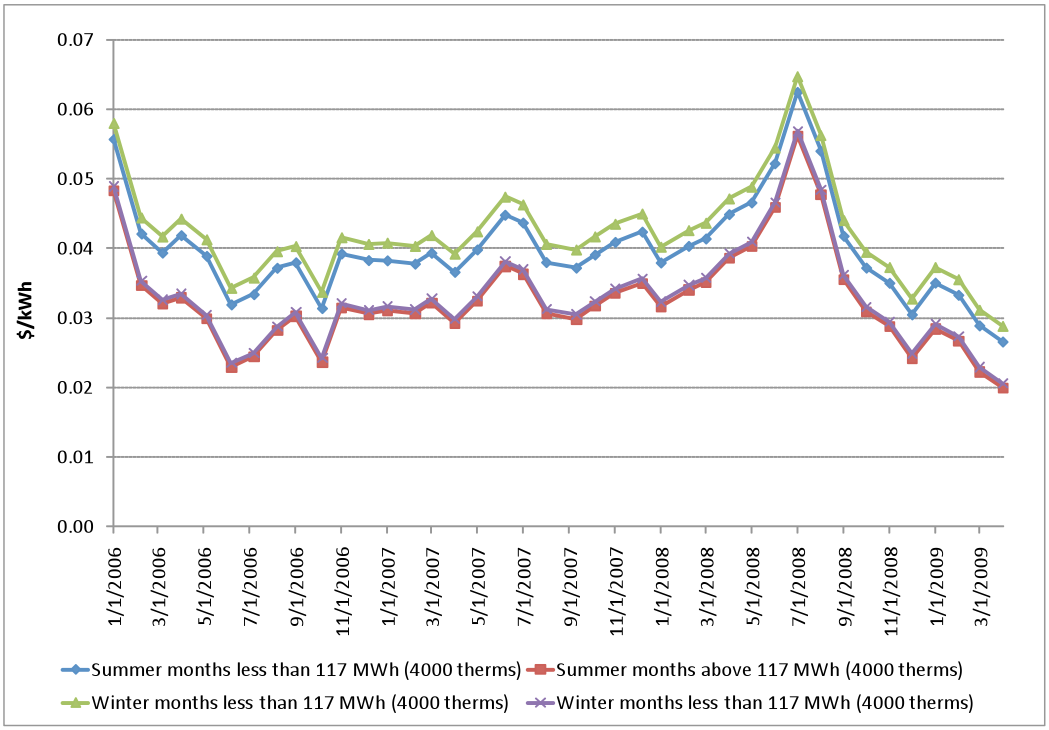
Source: CEUS and LBNL calculations

Figure B6. Natural Gas by End-Use

For more information on CEUS please refer to the California Commercial End-Use Survey database, ITRON at http://capabilities.itron.com/ceusweb/.

9.0 Appendix C: 2020 Tariffs Used in this Study

Please note that all cost data in this project is expressed in 2008 US$. In other words, the 2008 or 2009 observed electric tariffs for PG&E, SCE and SDG&E service territories are kept constant in real terms and are used as estimates for 2020. However, for the natural gas rates, a different approach has been used since the last two years have experienced volatile natural gas markets. Early 2009 natural gas rates are likely not a good estimate for 2020 natural gas price since this was in the middle of the recession and might be too low although estimates of U.S. gas reserves are rising rapidly at the moment. On the other hand, 2008 natural gas prices were extremely high due to the boom on the commodity markets and might be also not a good estimate. PG&E natural gas prices from March 2009 show roughly a 55% - 60% reduction compared to July 2008 (see Figure C1). Based on that observation, the average natural gas price between January 2006 and March 2009 was used as an estimate for 2020.



Source: PG&E G-NR1 and LBNL calculations

Figure C1. Historic PG&E Natural Gas G-NR1 Tariffs

9.1. PG&E Electric Rates

For the PG&E service territory three different tariffs were used (see also PG&E A-1, PG&E A-10, and PG&E E-19):

- for buildings with electric peak load 0 – 199 kW: flat tariff A-1, no demand charge, seasonal difference between winter and summer months is a factor of 1.45

Table C1. Applied 2020 PG&E Commercial Sector Electricity Prices, Electric Peak Load < 200 kW

Electricity	Summer (May – Oct.)		Winter (Nov. – Apr.)	
	electricity (US$/kWh)	demand (US$/kW)	electricity (US$/kWh)	demand (US$/kW)
Variable	0.20		0.14	
Fixed (US$/month)	13.31			

Source: PG&E A-1 and own calculations

- for buildings with electric peak load 200 kW – 499 kW: TOU tariff A-10, seasonal demand charge

Table C2. Applied 2020 PG&E Commercial Sector Electricity Prices, Electric Peak Load from 200 kW to 499 kW

Electricity	Summer (May – Oct.)		Winter (Nov. – Apr.)	
	electricity (US$/kWh)	demand (US$/kW)	electricity (US$/kWh)	demand (US$/kW)
non-coincident	na	10.27	na	5.76
on-peak	0.16			
mid-peak	0.14		0.11	
off-peak	0.13		0.10	
Fixed (US$/month)	118.28			

Source: PG&E A-10 and own calculations

summer on-peak: 12:00 – 18:00 during weekdays

summer mid-peak: 08:00 – 12:00 and 18:00 – 21:00 during weekdays

summer off-peak: 21:00 – 08:00 during weekdays and all weekends and holidays

winter mid-peak: 08:00 – 21:00 during weekdays

winter off-peak: 21:00 – 08:00 during weekdays and all weekends and holidays

- for buildings with electric peak load 500 kW and above: TOU tariff E-19, seasonal demand charge

Table C3. Applied 2020 PG&E Commercial Sector Electricity Prices, Electric Peak Load 500 kW and above

Electricity	Summer (May – Oct.)		Winter (Nov. – Apr.)	
	electricity (US$/kWh)	demand (US$/kW)	electricity (US$/kWh)	demand (US$/kW)
non-coincident	na	7.70	na	7.70
on-peak	0.16	13.51		
mid-peak	0.11	3.07	0.09	1.04
off-peak	0.09		0.08	
Fixed (US$/month)	406.57			

Source: PG&E E-19 and own calculations

summer on-peak: 12:00 – 18:00 during weekdays

summer mid-peak: 08:00 – 12:00 and 18:00 – 21:00 during weekdays

summer off-peak: 21:00 – 08:00 during weekdays and all weekends and holidays

winter mid-peak: 08:00 – 21:00 during weekdays

winter off-peak: 21:00 – 08:00 during weekdays and all weekends and holidays

9.2. PG&E Natural Gas Rates for all Building Sizes

Table C4. Applied 2020 PG&E Commercial Sector Natural Gas Prices

Natural Gas	
0.04	US$/kWh
64.48	fixed (US$/month)

Source: PG&E tariffs and LBNL calculations

9.3. SCE Electric Rates

For SCE service territory also three different tariffs were used (see also SCE GS-2, SCE TOU-GS-3, SCE TOU-8):

- for buildings with electric peak load 20 – 200 kW: flat tariff GS-2, seasonal difference between winter and summer months is a factor of 1.1 (energy) and 2.83 (demand charge)

Table C5. Applied 2020 SCE Commercial Sector Electricity Prices, Electric Peak Load between 20 kW and 200 kW

Electricity	Summer (June – Sept.)		Winter (Oct. – May.)	
	electricity (US$/kWh)	demand (US$/kW)	electricity (US$/kWh)	demand (US$/kW)
non-coincident	na	28.76	na	10.16
Variable	0.08		0.07	
Fixed (US$/month)	92.34			

Source: SCE GS-2 and own calculations

- for buildings with electric peak load 200 kW – 499 kW: tariff TOU-GS-3, seasonal demand charge

Table C6. Applied 2020 SCE Commercial Sector Electricity Prices, Electric Peak Load from 200 kW to 499 kW

Electricity	Summer (June – Sept.)		Winter (Oct. – Apr.)	
	electricity (US$/kWh)	demand (US$/kW)	electricity (US$/kWh)	demand (US$/kW)
non-coincident	na	10.47	na	10.47
on-peak	0.11	16.35		
mid-peak	0.09	5.61	0.09	
off-peak	0.06		0.06	
Fixed (US$/month)	358.05			

Source: SCE TOU-GS-3 and own calculations summer on-peak: 12:00 – 18:00 during weekdays

summer mid-peak: 08:00 – 12:00 and 18:00 – 23:00 during weekdays

summer off-peak: 23:00 – 08:00 during weekdays and all weekends and holidays

winter mid-peak: 08:00 – 21:00 during weekdays

winter off-peak: 21:00 – 08:00 during weekdays and all weekends and holidays

- for buildings with electric peak load 500 kW and above: tariff TOU-8, seasonal demand charge

Table C7. Applied 2020 SCE Commercial Sector Electricity Prices, Electric Peak Load 500 kW and above

Electricity	Summer (June – Sept.)		Winter (Oct. – Apr.)	
	electricity (US$/kWh)	demand (US$/kW)	electricity (US$/kWh)	demand (US$/kW)
non-coincident	na	11.54	na	11.54
on-peak	0.11	15.22		
mid-peak	0.09	5.14	0.09	
off-peak	0.06		0.06	
Fixed (US$/month)	446.85			

Source: SCE TOU-8 and own calculations

summer on-peak: 12:00 – 18:00 during weekdays

summer mid-peak: 08:00 – 12:00 and 18:00 – 23:00 during weekdays

summer off-peak: 23:00 – 08:00 during weekdays and all weekends and holidays

winter mid-peak: 08:00 – 21:00 during weekdays

winter off-peak: 21:00 – 08:00 during weekdays and all weekends and holidays

9.4. SCE Natural Gas Rates for all Building Sizes

Table C8. Applied 2020 SCE Commercial Sector Natural Gas Prices

Natural Gas	
0.03	US$/kWh
14.79	fixed (US$/month)

Source: SCE Tariffs and LBL calculations

9.5. SDG&E Electric Rates & Natural Gas Rates

Table C9. Applied 2020 SDG&E Commercial Sector Electricity Prices

Electricity	Summer (May – Sep.)		Winter (Oct. – Apr.)	
	electricity (US$/kWh)	demand (US$/kW)	electricity (US$/kWh)	demand (US$/kW)
non-coincident	na	12.80	na	12.80
on-peak	0.13	13.30	0.13	4.72
mid-peak	0.11		0.12	
off-peak	0.08		0.09	
Fixed (US$/month)	232.87/58.22[32]			

Source: SDG&E Tariffs and LBNL calculations

summer on-peak: 11:00 – 18:00 during weekdays

summer mid-peak: 06:00 – 11:00 and 18:00 – 22:00 during weekdays

summer off-peak: 22:00 – 06:00 during weekdays and all weekends and holidays

winter on-peak: 17:00 to 20:00 during weekdays

winter mid-peak: 06:00 – 17:00 and 20:00 – 22:00 during weekdays

winter off-peak: 22:00 – 06:00 during weekdays and all weekends and holidays

Table C10. Applied 2020 SDG&E Commercial Sector Natural Gas Prices

Natural Gas	
0.03	US$/kWh
112.18/ 11.22[33]	fixed (US$/month)

Source: SDG&E Tariffs and LBNL calculations

[32] Customers with an electric peak load above 500 kW pay $232.87/month. Customers with a peak less than 500 kW pay $58.22/month.

[33] Customers with a natural gas consumption above 615,302 kWh/month pay $112.18/month. Customers with a natural gas consumption less than 615,302 kWh/month pay $11.22/month.

10.0 Appendix D: Optimization Runs Performed

For every set of parameters two different runs were performed:

- A *do-nothing* case which does not allow any distributed generation (DG) or combined heat and power (CHP), and all energy needs to be purchased from the utility. This serves as reference case for the *invest* case.
- The *invest* case allows DG and CHP and is compared to the *do-nothing* case, and in this way cost reductions and CO_2 reductions can be calculated. Please note that strictly minimized building energy costs are found and only investments that result in a net cost reduction for the building are allowed.

Major Scenarios:

- Low natural gas (NG) prices in 2020, spring 2009 NG prices are kept constant in real terms, self generation incentive program (SGIP) of $500/kW for FCs, *run L.* Please note that this run does not use the NG prices from Appendix C. Instead, the following tariffs were used as sensitivity inputs

Table D1. Applied 2020 PG&E Commercial Sector Low Natural Gas Prices

Natural Gas	
0.03	US$/kWh
64.48	fixed (US$/month)

Source: PG&E tariffs and LBNL calculations

Table D2. Applied 2020 SCE Commercial Sector Low Natural Gas Prices

Natural Gas	
0.02	US$/kWh
14.79	fixed (US$/month)

Source: SCE Tariffs and LBL calculations

Table D3. Applied 2020 SDG&E Commercial Sector Low Natural Gas Prices

Natural Gas	
0.02	US$/kWh
112.18/ 11.22[34]	fixed (US$/month)

Source: SDG&E Tariffs and LBNL calculations

[34] Customers with a natural gas consumption above 615,302 kWh/month pay $112.18/month. Customers with a natural gas consumption less than 615,302 kWh/month pay $11.22/month.

- High NG prices in 2020, maximum NG prices in 2008 are kept constant in real terms, SGIP of \$500/kW for FCs, *run H.* Please note that this run does not use the NG prices from Appendix C. Instead, following tariffs were used as sensitivity inputs.

Table D4. Applied 2020 PG&E Commercial Sector <u>High</u> Natural Gas Prices

Natural Gas	
0.07	US\$/kWh
64.48	fixed (US\$/month)

Source: PG&E tariffs and LBNL calculations

Table D5. Applied 2020 SCE Commercial Sector <u>High</u> Natural Gas Prices

Natural Gas	
0.05	US\$/kWh
14.79	fixed (US\$/month)

Source: SCE Tariffs and LBL calculations

Table D6. Applied 2020 SDG&E Commercial Sector <u>High</u> Natural Gas Prices

Natural Gas	
0.05	US\$/kWh
112.18/ 11.22[35]	fixed (US\$/month)

Source: SDG&E Tariffs and LBNL calculations

- Medium NG prices in 2020, average of the NG prices between January 2006 and March 2009 are constant in real terms, SGIP of \$500/kW for FCs, *run M , "Reference Case"*. As also discussed in Appendix C this seems to be the most realistic assumption for the natural gas price, and therefore, we consider this as the *"Reference Case"*.
- Medium NG prices in 2020 and higher marginal CO_2 emission rates during off-peak hours in southern CA, SGIP of \$500/kW for FCs, *run M-hc*. This sensitivity run considers higher marginal CO_2 rates during off-peak hours of the electric tariff of 0.79kgCO_2/kWh for southern California (FZ 7, 8, 9, 10, and 13). See also Marnay et al. 2002.

[35] Customers with a natural gas consumption above 615,302 kWh/month pay \$112.18/month. Customers with a natural gas consumption less than 615,302 kWh/month pay \$11.22/month.

Table D7. Aggregate Results for 35% of California's Commercial Electric Demand, Runs Set 1[36]

do-nothing	run L	run H	run M	run M-hc
total annual costs (M$)	4859.7	5381.8	5030.8	5030.8
total annual CO_2 emissions (Mt/a)	19.7	19.7	19.7	21.4

invest	run L	run H	run M *Reference Case*	run M-hc
total annual costs (M$)	4103.6	5257.0	4843.1	4843.1
total annual CO_2 emissions (Mt/a)	18.5	18.7	18.4	19.7
total installed CHP capacity (GW)	4.7	0.1	1.4	1.4
total electricity produced by CHP (TWh)	24.1	0.4	7.2	7.2
total cooling offset[37] (TWh)	2.2	0.0	0.4	0.4
changed costs compared to do-nothing (%)	-15.6	-2.3	-3.7	-3.7
changed CO_2 compared to do-nothing (%)	-6.2	-4.9[38]	-6.7	-7.9
average CHP capacity factor (%)	58.8	55.5	59.5	59.5

- Medium NG prices in 2020 and higher marginal CO_2 emission rates during off-peak hours in southern CA as in the run before and SGIP incentive of $750/kW for FCs, *run M-hc-SGIP.*
- Medium NG prices in 2020 and no min. load constraint, SGIP of $500/kW for FCs, *run M-no-min.* Please note that for all other runs a minimum load constraint of 0.5 is imposed and the DG units, e.g. ICEs or FCs cannot operate with less than 50% nameplate capacity.
- Medium NG prices in 2020 and only FCs are allowed, SGIP of $500/kW for FCs, *run M-onlyFC*.
- Medium NG prices in 2020, high marginal CO_2 missions in Southern CA, no PV and no solar thermal is allowed, SGIP of $500/kW for FCs, *run M-hc-noPVSolar*
- Medium NG prices in 2020 and a 4% interest rate, SGIP of $500/kW for FCs, *run M-4%i.* Please note that all other runs use 6% interest rate
- $150/tC (= $40.1/tCO2) carbon tax run with PV / solar thermal as possible option, SGIP of $500/kW for FCs, *run M-lowCtax*
- $150/tC (= $40.1/tCO2) carbon tax run without PV / solar thermal as possible option, SGIP of $500/kW for FCs, *run M-lowCtax-noPVSolar*
- $450/tC (= $122.7/tCO2) carbon tax run with PV / solar thermal as possible option, SGIP of $500/kW for FCs, *run M-medCtax*

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[36] Numbers have been rounded.

[37] Due to absorption chillers.

[38] Due to increased PV and solar thermal adoption.

Table D8. Aggregate Results for 35% of California's Commercial Electric Demand, Runs Set 2[39]

do-nothing	run M-hc-SGIP	run M-no-min	run M-onlyFC	run M-hc-noPVSolar
total annual costs (M$)	5030.8	5030.8	5030.8	5030.8
total annual CO_2 emissions (Mt/a)	21.4	19.7	19.7	21.4
invest	**run M-hc-SGIP**	**run M-no-min**	**run M-onlyFC**	**run M-hc-noPVSolar**
total annual costs (M$)	4842.0	4838.5	4921.1	4857.6
total annual CO_2 emissions (Mt/a)	19.6	18.3	18.5	20.0
total installed CHP capacity (GW)	1.4	1.5	0.7	1.5
total electricity produced by CHP (TWh)	7.3	7.5	3.7	7.4
total cooling offset (TWh)	0.4	0.3	0.0	0.4
changed costs compared to do-nothing (%)	-3.8	-3.8	-2.2	-3.4
changed CO_2 compared to do-nothing (%)	-8.1	-6.9	-6.1	-6.4
average CHP capacity factor (%)	60.0	55.3	63.6	57.9

Table D9. Aggregate Results for 35% of California's Commercial Electric Demand, Runs Set 3[40]

do-nothing	run M-4%i	run M-lowCtax	run M-lowCtax-noPVSolar	run M-medCtax
total annual costs (M$)	5030.8	5837.4	5837.4	7449.0
total annual CO_2 emissions (Mt/a)	19.7	19.7	19.7	19.7
invest	**run M-4%i**	**run M-lowCtax**	**run M-lowCtax-noPVSolar**	**run M-medCtax**
total annual costs (M$)	4757.0	5574.5	5624.5	6885.8
total annual CO_2 emissions (Mt/a)	17.5	17.8	18.7	15.2
total installed CHP capacity (GW)	1.4	1.4	1.5	1.5
total electricity produced by CHP (TWh)	7.4	7.3	7.5	6.5
total cooling offset (TWh)	0.4	0.4	0.4	0.2
changed costs compared to do-nothing (%)	-5.4	-4.5	-3.6	-7.6
changed CO_2 compared to do-nothing (%)	-10.9[41]	-9.9	-5.2	-22.9
average CHP capacity factor (%)	58.8	58.0	56.6	48.7

39 Numbers have been rounded.

40 Numbers have been rounded.

41 Due to increased PV and solar thermal adoption.

- \$450/tC (= \$122.7/tCO_2) carbon tax run without PV / solar thermal as possible option, SGIP of \$500/kW for FCs, *run M-medCtax-noPVSolar*
- \$1000/tC (= \$272.7/tCO_2), carbon tax run with PV / solar thermal as possible option, SGIP of \$500/kW for FCs, *run M-highCtax*
- \$1000/tC (= \$272.7/tCO_2), carbon tax run without PV / solar thermal as possible option, SGIP of \$500/kW for FCs, *run M-highCtax-noPVSolar*
- Medium NG prices in 2020 and a Feed-in Tariff (FiT), which reflects the whole purchase tariff, the FiT applies to all DG technologies, no SGIP is used, *run M-FiT*. Please note that also a purchase constraint, purchase 👓 sales is used. This constraint is needed to prevent some sites from installing CHP without limits, which can drive the energy conversion efficiency near the macrogrid efficiency of ca. 34% since most of the waste heat could not be utilized because of limited onsite heat loads.

Table D10. Aggregate Results for 35% of California's Commercial Electric Demand, Runs Set 4[42]

do-nothing	run M-medCtax-noPVSolar	run M-highCtax	run M-highCtax-noPVSolar	run M-FiT
total annual costs (M\$)	7449.0	10408.1	10408.1	5030.8
total annual CO_2 emissions (Mt/a)	19.7	19.7	19.7	19.7

invest	run M-medCtax-noPVSolar	run M-highCtax	run M-highCtax-noPVSolar	run M-FiT
total annual costs (M\$)	7147.2	9068.2	9934.4	4828.0
total annual CO_2 emissions (Mt/a)	18.6	13.9	18.0	18.2
total installed CHP capacity (GW)	1.7	1.5	2.2	1.5
total electricity produced by CHP (TWh)	8.1	7.0	10.7	7.5
total cooling offset (TWh)	0.4	0.1	0.2	0.4
changed costs compared to do-nothing (%)	-4.1	-12.9	-4.6	-4.0
changed CO_2 compared to do-nothing (%)	-5.6	-29.2[43]	-8.5	-7.7
average CHP capacity factor (%)	53.1	52.7	54.8	58.5

- Medium NG prices in 2020 and a FiT, which reflects the whole purchase tariff, the FiT applies to all CHP technologies, no SGIP is used, without PV / solar thermal as possible option, *run M-FiT noPVSolar*

[42] Numbers have been rounded.

[43] Due to increased PV and solar thermal adoption.

- Medium NG prices in 2020 and a high SGIP incentive of $1500/kW (=60% of the 2008 incentive value) for FCs and a 60% annual efficiency constraint for FCs using SGIP, which requires that the FCs run above 60% total efficiency on an annual basis, *run M-SGIP60%*.

Table D11. Aggregate Results for 35% of California's Commercial Electric Demand, Runs Set 5[44]

do-nothing	run M-FiT noPVSolar	run M-SGIP60%
total annual costs (M$)	5030.8	5030.8
total annual CO_2 emissions (Mt/a)	19.7	19.7
invest	**run M-FiT noPVSolar**	**run M-SGIP60%**
total annual costs (M$)	4848.9	4706.9
total annual CO_2 emissions (Mt/a)	18.7	17.9
total installed CHP capacity (GW)	1.6	2.9
total electricity produced by CHP (TWh)	8.0	10.3
total cooling offset (TWh)	0.5	0.6
changed costs compared to do-nothing (%)	-3.6	-6.4
changed CO_2 compared to do-nothing (%)	-5.1	-9.3
average CHP capacity factor (%)	57.7	40.8

[44] Numbers have been rounded.

Table D12. Forecasting Climate Zone Results for run M, *Reference Case*[45]

do-nothing	FZ01 PG&E	FZ03 PG&E	FZ04 PG&E	FZ05 PG&E	FZ07 SCE	FZ08 SCE	FZ09 SCE	FZ10 SCE	FZ13 SDG&E
total annual costs (M$)	39.98	306.24	866.21	993.56	55.05	859.99	819.00	362.54	728.23
total annual CO_2 emissions (Mt/a)	0.14	1.10	3.15	3.70	0.23	3.73	3.49	1.55	2.61

invest	FCZ01 PG&E	FCZ03 PG&E	FCZ04 PG&E	FCZ05 PG&E	FCZ07 SCE	FCZ08 SCE	FCZ09 SCE	FCZ10 SCE	FCZ13 SDG&E
total annual costs (M$)	39.76	301.70	852.60	970.84	54.63	854.33	811.94	358.38	598.93
total annual CO_2 emissions (Mt/a)	0.14	1.03	2.94	3.37	0.23	3.58	3.38	1.47	2.26
total installed CHP capacity (MW)	2.25	25.75	64.99	298.80	8.50	170.75	259.50	59.25	497.89
total electricity produced by CHP (GWh)	9.03	169.38	415.88	1575.18	32.57	793.33	833.77	355.24	3043.55
total cooling offset (GWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.87	349.86
changed costs compared to do-nothing (%)	-0.55	-1.48	-1.57	-2.29	-0.78	-0.66	-0.86	-1.15	-17.75
changed CO_2 compared to do-nothing (%)	-3.63	-6.24	-6.79	-8.87	-3.24	-4.06	-3.03	-5.28	-13.44
average CHP capacity factor (%)	45.82	75.09	73.05	60.18	43.75	53.04	36.68	68.44	69.78

[45] Numbers have been rounded.

Table D13. Forecasting Climate Zone Results for run M-SGIP60%[46]

do-nothing	FZ01 PG&E	FZ03 PG&E	FZ04 PG&E	FZ05 PG&E	FZ07 SCE	FZ08 SCE	FZ09 SCE	FZ10 SCE	FZ13 SDG&E
total annual costs (M$)	39.38	306.24	866.21	993.56	55.05	859.99	819.00	362.54	728.23
total annual CO_2 emissions (Mt/a)	0.14	1.10	3.15	3.70	0.23	3.73	3.49	1.55	2.61
invest	**FCZ01 PG&E**	**FCZ03 PG&E**	**FCZ04 PG&E**	**FCZ05 PG&E**	**FCZ07 SCE**	**FCZ08 SCE**	**FCZ09 SCE**	**FCZ10 SCE**	**FCZ13 SDG&E**
total annual costs (M$)	39.38	295.50	847.80	945.30	52.98	832.27	774.55	351.23	567.87
total annual CO_2 emissions (Mt/a)	0.14	1.02	2.94	3.34	0.22	3.51	3.23	1.41	2.06
total installed CHP capacity (MW)	14.75	173.25	265.15	553.05	34.25	355.25	591.00	254.25	652.45
total electricity produced by CHP (GWh)	30.47	410.11	825.38	1701.54	97.39	1224.00	1700.18	839.52	3509.82
total cooling offset (GWh)	1.96	20.11	17.49	38.83	2.70	77.48	141.21	45.80	216.75
changed costs compared to do-nothing (%)	0.00	-3.51	-2.13	-4.86	-3.76	-3.22	-5.43	-3.12	-22.02
changed CO_2 compared to do-nothing (%)	-4.30	-7.97	-6.63	-9.55	-6.81	-5.93	-7.27	-8.92	-21.13
average CHP capacity factor (%)	23.59	27.02	35.54	35.12	32.46	39.33	32.84	37.69	61.41

11.0 Appendix E: Discussion of NOx emissions

Because of the dominance of internal combustion engines, a discussion of the nitrogen oxides (NOx) emissions is presented. California has regulations on NOx emissions and requires that fossil based DG/CHP systems sold in California be certified to meet 0.32 g/MWh (0.07 lb/MWh) emissions standards, based on the electric output. However, CHP units may take a credit to meet the emission standard above. To take the credit, the CHP units have to achieve a minimum energy efficiency of 60 percent (see also CARB 2006).

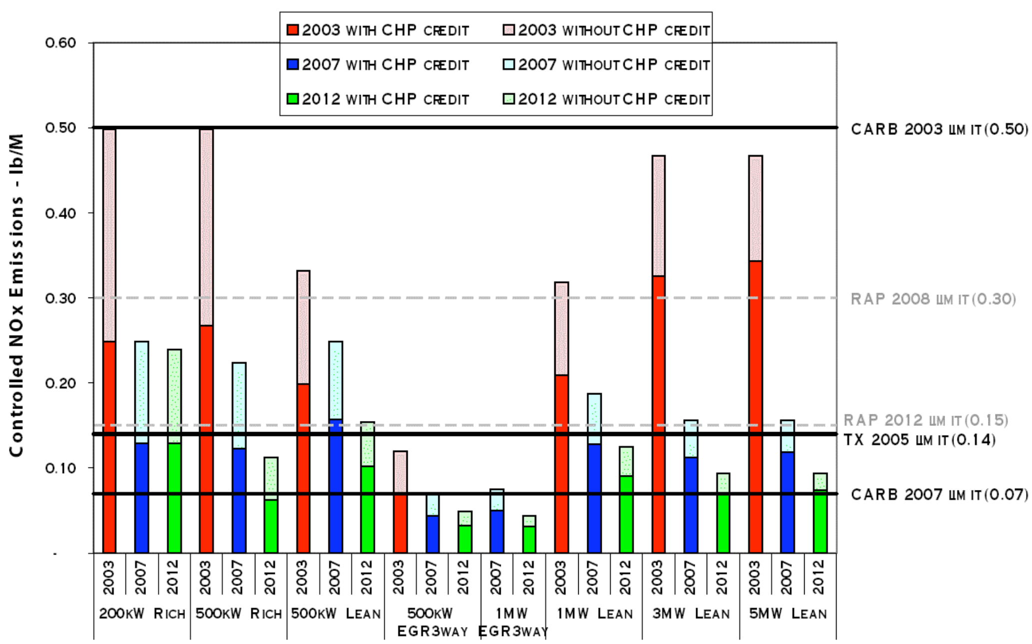
To account for expensive emission control systems, the capital costs for ICEs in this work are assumed to be at the upper end of the cost range. A 250 kW ICE CHP system with extravagant NOx emission control system can cost up to $2180/kW. Comparing these costs to Goldstein et al. 2003, these result in approximately 70% higher capital costs for the ICE CHP systems and should be sufficient to account for any expensive NOx control systems. Also, the

[46] Numbers have been rounded.

technology data used in this work are partly based on SGIP data and these data also contains costs for emission control systems and other air quality related costs. However, please note that despite the high capital costs ICEs are still very dominant and would create the largest potential in 2020 (please see Appendix D, run M *Reference Case*).

Based on DE Solutions, Inc. and the Figure below, the 500 kW rich burn engines with three-way catalyst will probably meet the CARB 2007 limit by 2012. In the accelerated case[47], which is not shown in Figure E1, the 200 kW rich burn engine will also meet the CARB 2007 standard by 2012. However, none of the lean burn engines will meet the CARB standard by 2012, except for the large engines which are right at the limit of 0.07 lb/MWh with the CHP credit. The 1, 3, and 5 MW lean burn engines would meet the CARB 2007 limits by 2012 in the accelerated case with heat recovery credit, which is not shown in the Figure below.

Based on DE Solutions, Inc., the reciprocating engines with exhaust gas recirculation and three way catalysts show good potential to meet CARB 2007 limits in CHP applications after the year 2012.



Source: DE Solutions, Inc. 2004, page 28

Figure E1. NOx Emissions (lb/MWh) for ICEs, Californa Air resources Board (CARB) and Texas Natural Resources and Conservation Commission (TNRCC)

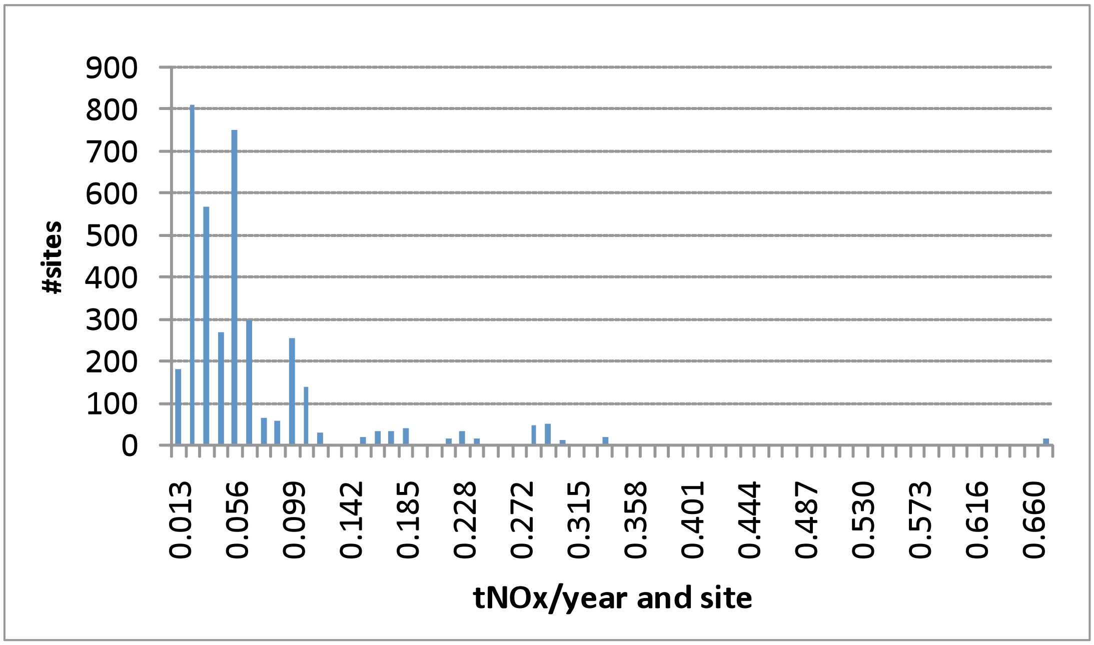
Based on these findings it is assumed that ICEs meet CARB 2007 limits in 2020.

The DER-CAM runs deliver a maximum annual NOx emission of 0.67tNOx/site[48] and year for the reference case with ICEs as dominant technology (please see Appendix D,

[47] Different scenarios were performed from DE Solutions, Inc.: a) limited, b) base, and c) accelerated. For a detailed description of the cases please refer to DE Solutions, Inc. 2004.

[48] Metric tons.

run M *Reference Case)*. The site with the maximum NOx emissions is a large College (COLL) in FZ13 SDG&E with a capacity factor of 0.6. Please note that DER-CAM does not assume a certain capacity factor. In reality, capacity factors vary depending on the site, and therefore, the NOx emissions can be very different for different sites and climate zones. Figure E2 shows the NOx emission distribution for the different sites simulated in this work. The vast majority of sites emit less than 0.1tNOx/site. The large College in FZ13 SDG&E with the maximum NOx emissions of 0.67tNOx/site is shown at the right hand side of Figure E2.



Source: LBNL calculations

Figure E2. NOx Emission Histogram for Simulated Buildings/Sites

According to Rule 1304 (see also SCAQMD) new facilities do not need offsets if they have the *potential* to emit less than 3.6tNOx/year[49]. However, if a fossil based DG/CHP system emits more than 3.6tNOx/year, then it would be required to offset the NOx emissions. Assuming that the potential emissions are calculated based on a capacity factor of 100%, the optimization run for the large College in FZ13 SDG&E delivers 1.11tNOx/year and would comply with Rule 1304.

It can be assumed that ICEs meet the current strict air quality regulation in California by 2020, but stricter regulations on NOx might create a problem for ICE adoption. Also, as shown by the FiT runs[50] the low electric efficiency of ICEs might create a CO_2 problem and will limit the benefit of a FiT for CHP systems. Therefore, the case with a high SGIP incentive of $1500/kW

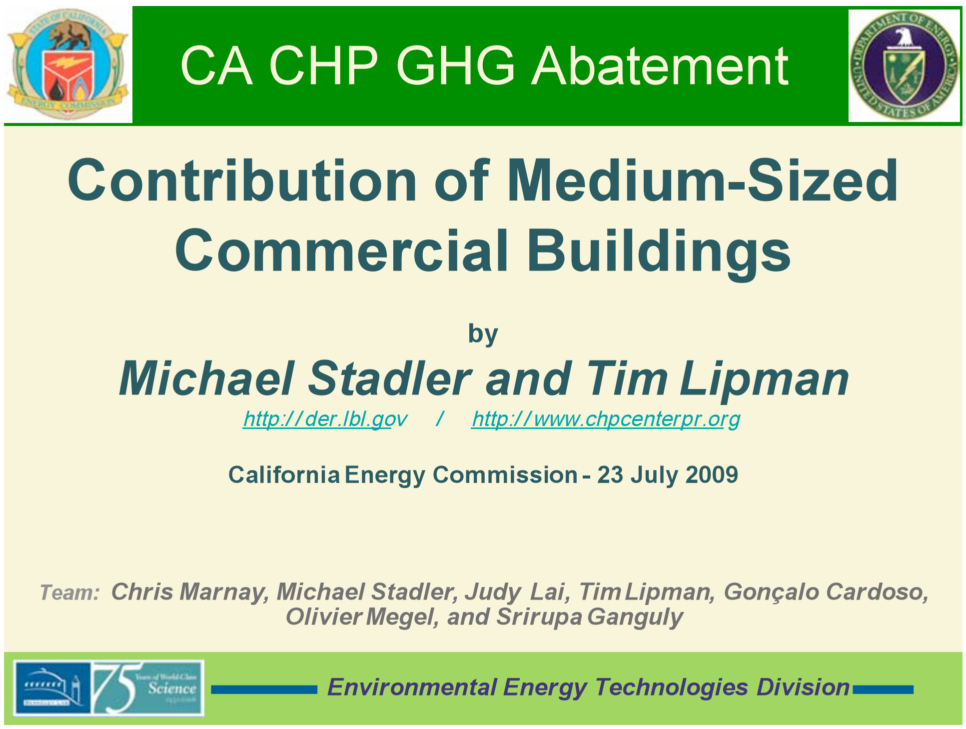
[49] Metric tons.

[50] Please refer to Appendix D, Table D10 run M-FiT and Table D11 run M-FiT noPVSolar.

for fuel cells[51] will limit any NOx as well as CO_2 problem in 2020 (see also Section 4 and fourth scenario).

12.0 Appendix F: IEPR Committee Workshop Presentation

Following presentation was given at the IEPR Committee Workshop, CHP to Support California's AB32 Climate Change Scoping Plan at the California Energy Commission on July 23rd 2009. Please note that some results shown at the IEPR workshop might slightly deviate from the final results because some data has been updated since July 2009.



[51] For more details please refer to Appendix D, Table D11 run M-SGIP60%.

Outline

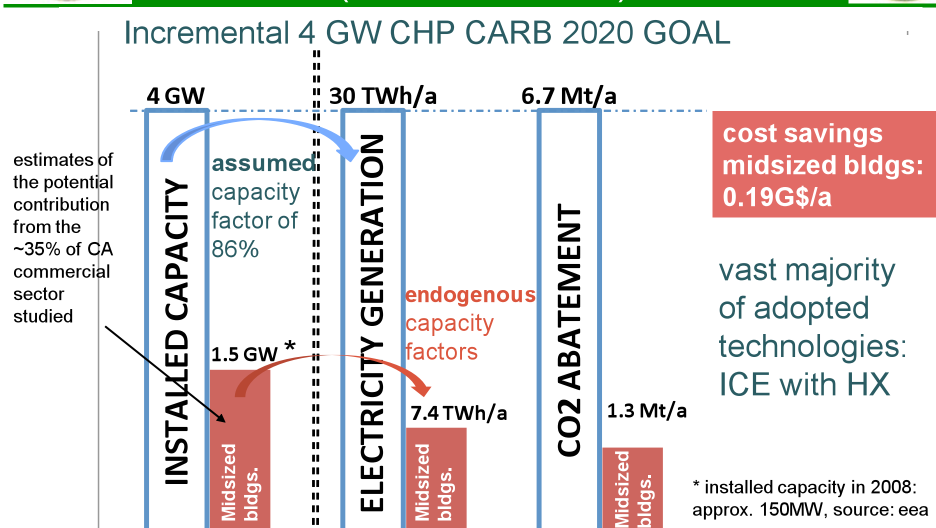
- Study Overview
- DER-CAM Overview, the **D**istributed **E**nergy **R**esources **C**ustomer **A**doption **M**odel
- CEUS Database
- Results for Medium-Sized Commercial Buildings
- PRAC Update
- "Appendix": More CEUS / Result Background

Study Overview:
CHP in CA Medium-Sized Commercial Buildings

Study Summary

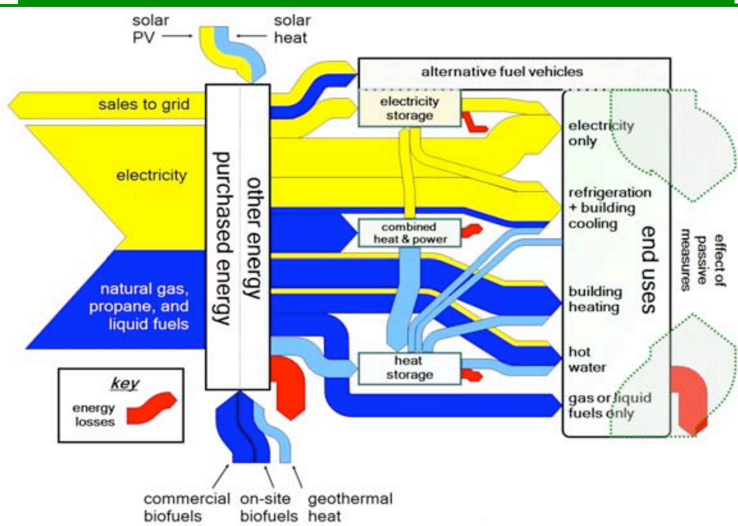
- objective: to estimate the 2020 CO_2 abatement potential of CHP for medium-sized CA commercial buildings (100 kW – 5 MW electric peak load)
- pick a sample of representative buildings from CEUS
- use DER-CAM to examine CHP attractiveness in sample, with competition from other technologies, e.g. PV
- estimate and report CO_2 results relative to CARB goals
- model reference case and alternative scenarios including carbon taxes and "feed-in tariff" (FiT) cases in relation to AB 32 and AB 1613
- propose further work in this under-explored sector

Results Summary
(Reference Case)



Distributed Energy Resources Customer Adoption Model (DER-CAM)

DER-CAM Concept

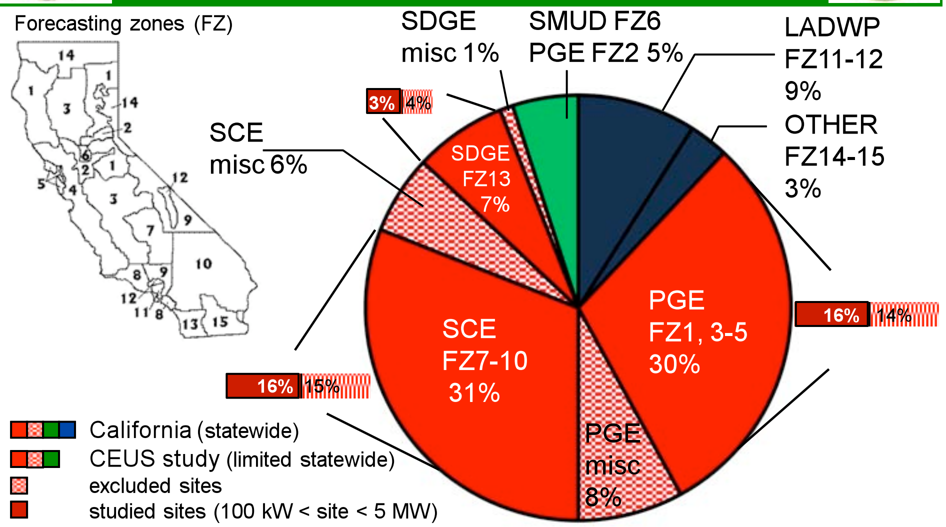


Key Features DER-CAM

- considers multiple technologies as CHP, PV, solar thermal, and storage at the same time
- optimizes costs and / or CO_2 emissions
- uses a bottom up approach, every single building is considered in detail
- can also analyze zero-net energy buildings by adding that as a constraint

CEUS Database

35% of Commercial Electric Demand



Building Data Sample

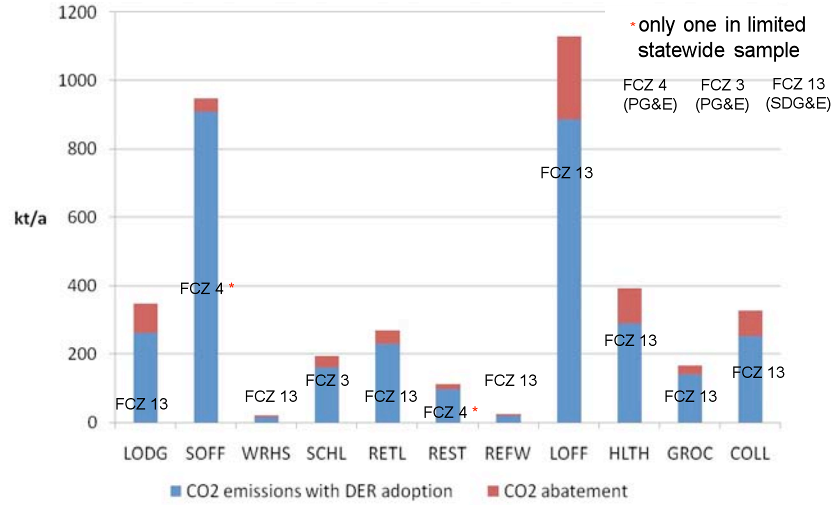
- Objective: to estimate the 2020 CO_2 abatement potential of CHP for medium-sized CA commercial buildings (100 kW – 5 MW electric peak load)
- Scope: buildings with electricity peak within range of 100 kW – 5 MW (35% of total electric demand)
- Building sample: 138 buildings of different types and in various climate zones

Results for Medium-Sized Commercial Buildings

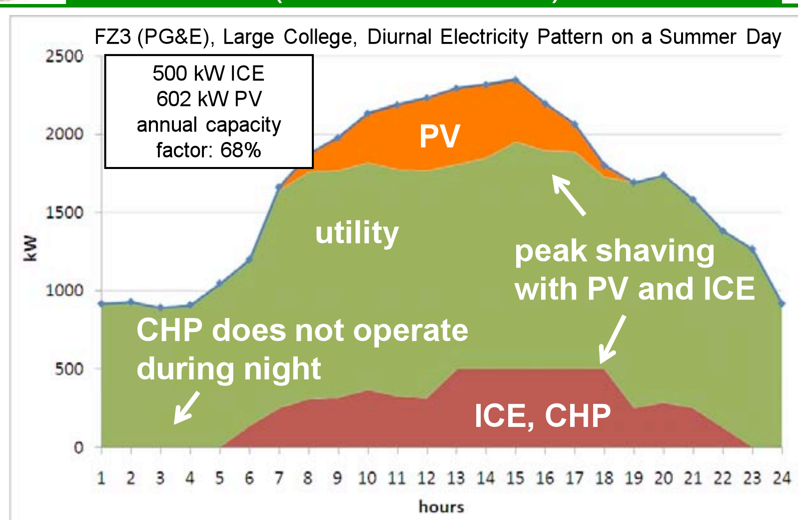
Key Assumptions

- not only CHP is considered, also PV, solar thermal
- technology costs in 2020 are based on "Assumptions to the Annual Energy Outlook", e.g.
  - FC with HX: $2220 - $2770/kW, lifetime: 10 years
  - ICE with HX: $2180 - $3580/kW, lifetime: 20 years
  - PV: $3237/kW, lifetime: 20 years
  - etc.
- natural gas tariffs are constant in real terms
- electricity tariffs from early 2009 / late 2008 are used and constant in real terms
- 6% real interest rate (except one sensitivity run)

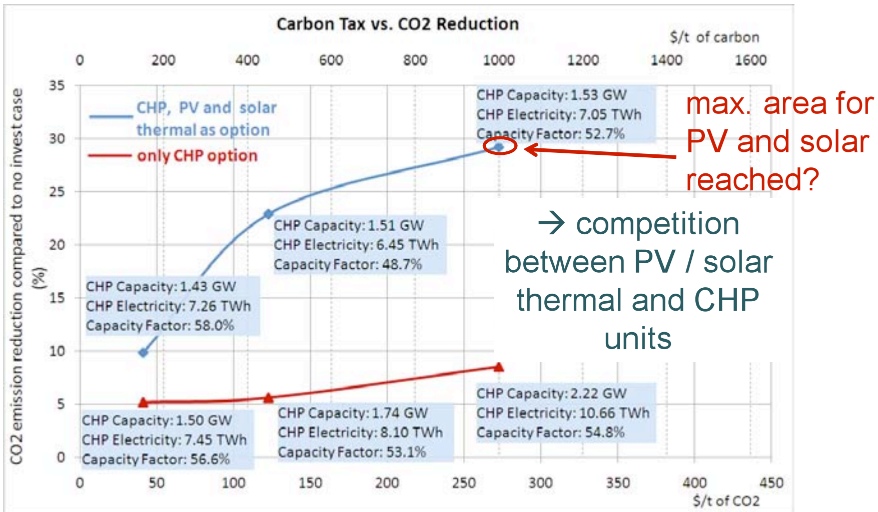
CO_2 Abatement Best Bldgs.
(Reference Case)



Electric Supply Results
(Reference Case)

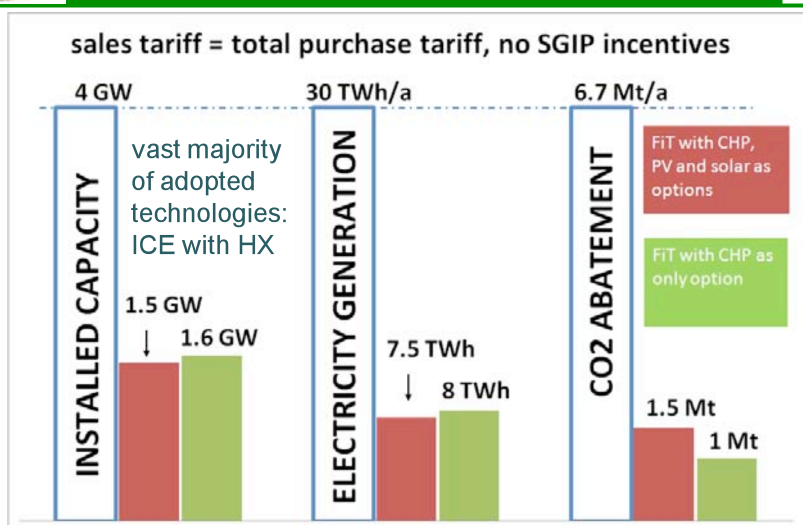


Carbon Tax Cases
(for Considered Midsized Bldgs.)



Environmental Energy Technologies Division 16

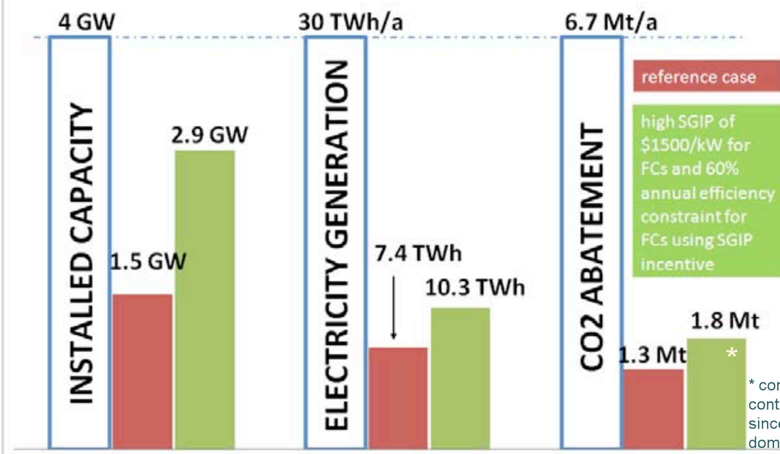
Feed-in Tariff



Environmental Energy Technologies Division 17

High SGIP for FCs versus Reference Case

High SGIP: vast majority of adopted technologies are FCs with HX



* contains a negligible contribution from PV since FCs are very dominant in this case

Observations

- DER-CAM delivers highly variable capacity factors between 30% and 88% depending on the considered site and tariff
  - an average capacity factor of 55% is observed in the reference case
  - high average capacity factors of 86% assumed by ARB in scoping plan appear unrealistic
- The lower observed capacity factors impact the electricity generation from CHP considerably
- Carbon taxes drive CHP and PV / solar thermal adoption

Conclusions

- In the reference case, 1.5 GW of CHP is adopted through 2020 in this analysis of the medium-size commercial sector
  - high SGIP case raises this to 2.9 GW
- FiT slightly increases the energy output from CHP
- SGIP for FCs has a big impact
- Future work:
  - more work on appropriate FiT tariffs and impacts on adoption and capacity factors
  - interaction between PV, solar thermal, and CHP
  - effect of inclusion of storage technologies

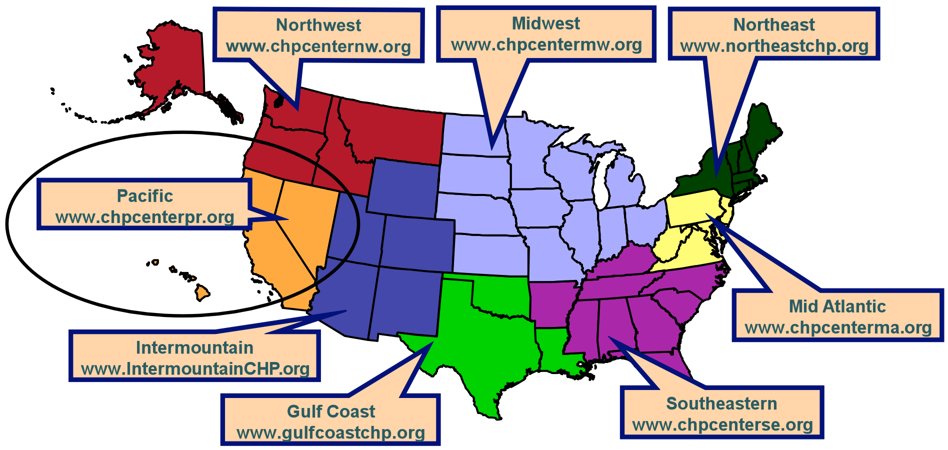
PRAC Update

PRAC Update

- PRAC is the Pacific Region Combined Heat and Power Application Center, operated by UC Berkeley, UC Irvine, and San Diego State University since 2005
- Sponsored by U.S. DOE and the CA Energy Commission, and with involvement from key partners including electric and gas utilities, Berkeley Lab, CA Clean DG Coalition, etc.
- One of eight DOE regional application centers for CHP
- Has conducted a range of educational, outreach, and direct project assistance activities to promote appropriate CHP adoption in the Pacific Region: CA, NV, HI
- PRAC: http://www.chpcenterpr.org

Regional CHP App. Centers

Promoting CHP technology and practices as well as identifying and implementing regional CHP projects



PRAC Update (cont'd)

Workplan for the new center phase:

- maintain and expand PRAC website
- target market workshops
- waste-heat-to-energy workshop
- revised state "baseline assessment and action plan" reports
- project case study profiles
- policy roadmapping with stakeholders
- identify and facilitate high impact projects
- project management

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Thank you!