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Disclaimer

The Influence of a CO_2 Pricing Scheme on Distributed Energy Resources in California's Commercial Buildings[1]

Michael Stadler[2], Chris Marnay[3], Judy Lai[4], Gonçalo Cardoso[5], Olivier Mégel[6], and Afzal Siddiqui[7]

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 energy resources (DER) with combined heat and power (CHP) in greenhouse gas emissions (GHG) reductions. Historically, relatively little attention has been paid to the potential of medium-sized commercial buildings with peak electric loads ranging from 100 kW to 5 MW. In our research, we examine how these medium-sized commercial buildings might implement DER and CHP. The buildings are able to adopt and operate various technologies, e.g., photovoltaics (PV), on-site thermal generation, heat exchangers, solar thermal collectors, absorption chillers, batteries and thermal storage systems.

We apply the Distributed Energy Resources Customer Adoption Model (DER-CAM), which is a mixed-integer linear program (MILP) that minimizes a site's annual energy costs and/or CO_2 emissions. Using 138 representative mid-sized commercial sites in California, existing tariffs of major utilities, and expected performance data of available technologies in 2020, we find the GHG reduction potential for these buildings. We compare different policy instruments, e.g., a CO_2 pricing scheme or a feed-in tariff (FiT), and show their contributions to the California Air Resources Board (CARB) goals of additional 4 GW CHP capacities and 6.7 Mt/a GHG reduction in California by 2020. By applying different price levels for CO_2, we find that there is competition between fuel cells and PV/solar thermal. It is found that the PV/solar thermal adoption increases rapidly, but shows a saturation at high CO_2 prices, partly due to limited space for PV and solar thermal. Additionally, we find that large office buildings are good hosts for CHP in general. However, most interesting is the fact that fossil-based CHP adoption also increases with increasing CO_2 prices. We will show service territory specific results since the attractiveness of DER varies widely by climate zone and service territory.

Keywords: combined heat and power, CHP, CO_2 emissions, distributed energy resources, GHG control, microgrids, policies

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1. Introduction

A microgrid is 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 Hatziargyriou et al. 2007 and Microgrid Symposiums 2005-2009). Please note that microgrids can consist of multiple buildings/locations or just of a single building/location and in this paper we consider microgrids on a building level at a single site.

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 paper, 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 (Stadler et al. 2009). 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 paper 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 it potential is already being realized (see also 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 (see also Combined Heat and Power Installation Database). 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, 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 (see also Stadler et al. 2009a 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[8] in different climate zones 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.

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

The Global Warming Solutions Act of 2006 (AB-32) designates the California Air Resource Board (CARB) to be the lead implementing agency. It has prepared a scoping plan for achieving reductions in GHG emissions (see also CARB 2009), which considers CHP as an important option. The CARB goal of 4MW of statewide incremental installed CHP capacity in 2020 translates into a 6.7Mt/a CARB GHG reduction goal. This research has shown that the attractiveness of DER and CHP varies considerably between the nine considered CA climate zones and utilities, and therefore, this paper reports on the policy differences in the three major electric utility territories considered in this work. We show Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego and Gas Electric (SDG&E) specific results for the major policies discussed, i.e. a CO_2 pricing scheme and a feed-in-tariff for DER and CHP technologies.

2. 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 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[9]. 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,[10] 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.

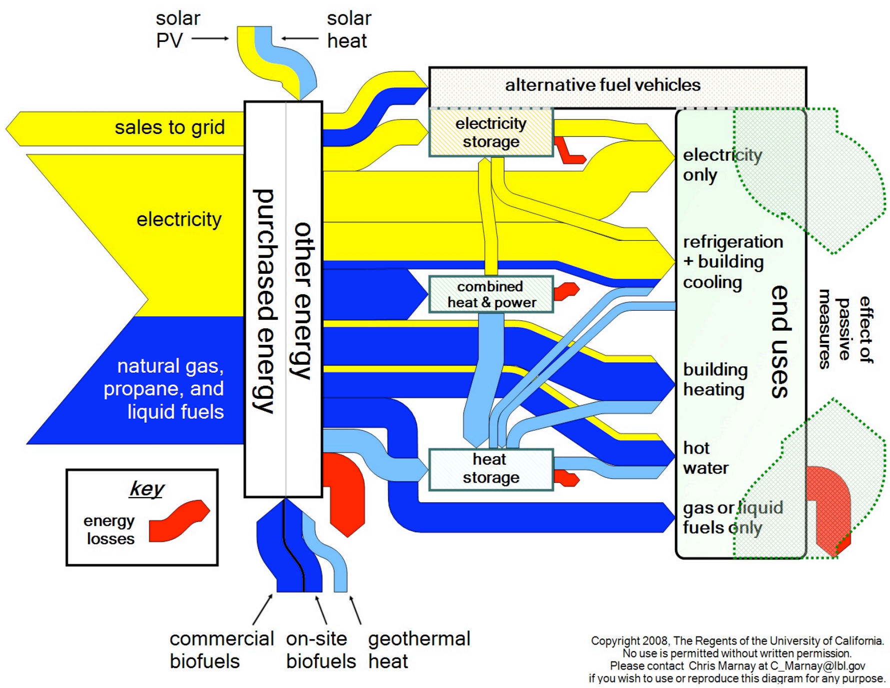
Figure 1 shows a high-level schematic of the building energy flows modeled in DER-CAM. Available energy inputs to the site are solar radiation, utility electricity, utility natural gas, biofuels, and geothermal heat. For a given site, DER-CAM selects the economically or environmental optimal combination 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;

[9] End-use efficiency is not considered in this paper (see also Stadler 2009).
[10] 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; and,
- 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.

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 discharged 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 paper. For a complete mathematical formulation of the MILP with energy storage solved by DER-CAM, please refer to Stadler et al. 2008.

Figure 2. Schematic of Information Flow in DER-CAM

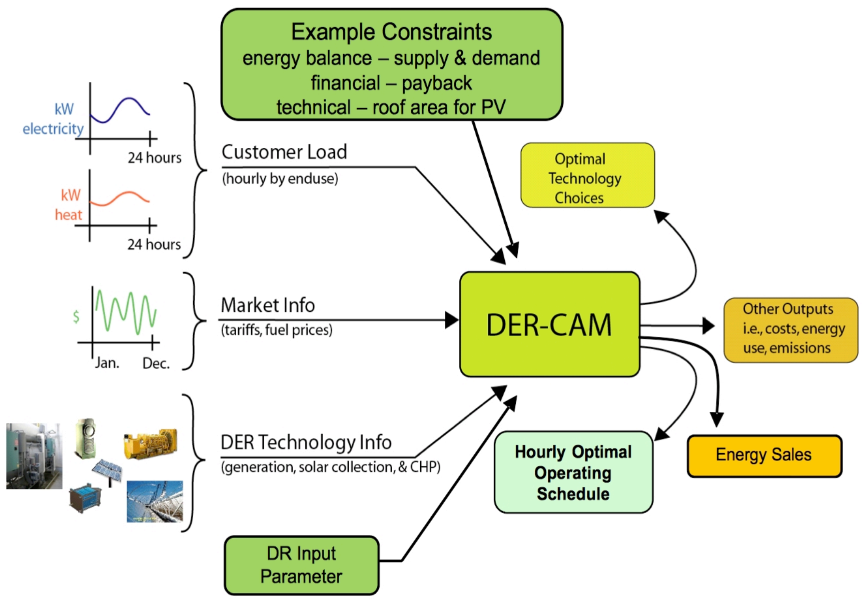
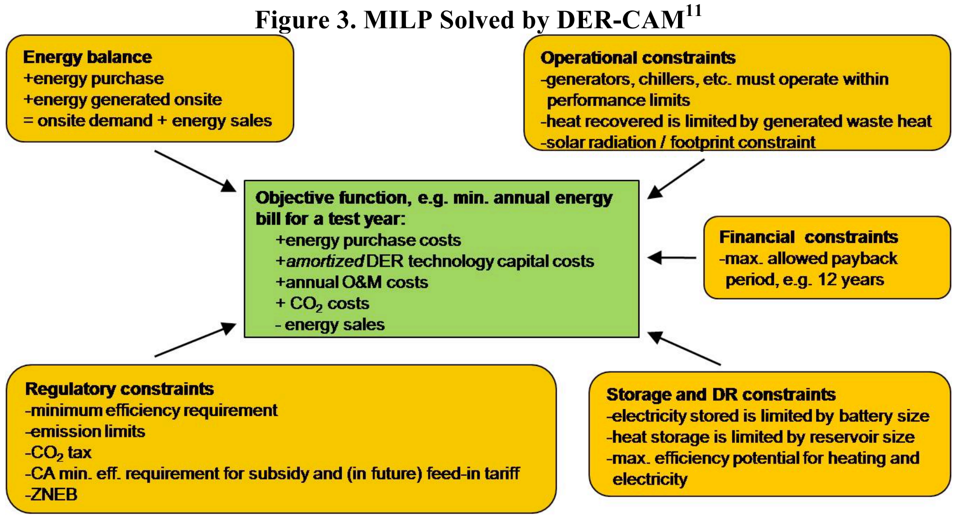


Figure 3. MILP Solved by DER-CAM[11]



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

3. Data

3.1. Commercial Buildings

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 subdivided into

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

The 12 commercial building types considered in CEUS are:

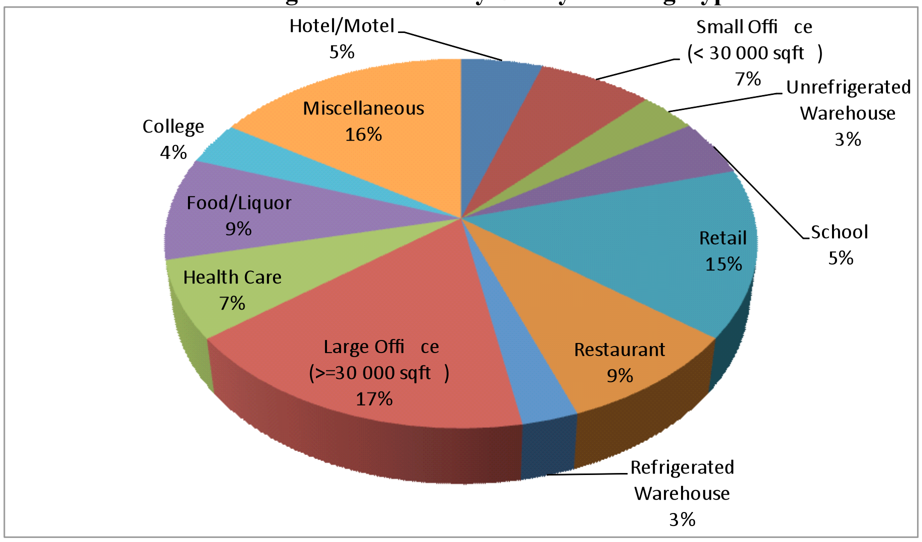
- small office (<30 000 sqft)
- large office (≥30 000 sqft)
- restaurant
- retail
- food/liquor
- unrefrigerated warehouse
- refrigerated warehouse
- school
- college
- health care
- hotel/motel
- miscellaneous (not considered in this study).

Figure 4 and Figure 5 show the electricity and natural gas use by building type and indicate that large offices and health care facilities might be good candidates for CHP systems since they show considerable natural gas and electric loads. However, the high natural gas use in restaurants would also suggest that restaurants would be good candidates for CHP systems, which turns out not being true within this work. The reason can be found in the typical size of a restaurant; only one restaurant in the CEUS database has an electric peak load above 100 kW, which is the cut off size within this study. This fragmentation will make it difficult to adopt CHP in this segment. However, more work on this building type, which demands 25% of the total natural gas in the commercial sector is planned.

Finally, it needs to be pointed out that the attractiveness of CHP is highly influenced by the simultaneity of electricity and heating/cooling loads on a daily basis; both demands need to occur roughly at the same time to be able to utilize waste heat from CHP systems. Of course, the use of electric and heat storage systems would remedy this, but as shown in the result section, storage systems are not economically attractive. Based on this reflection, health care, large office buildings, colleges/schools, and hotels/motels are good candidates for CHP systems. Figure 6 and Figure 7 show the simultaneity of the electricity, cooling, and domestic hot water load for a healthcare facility in SDG&E service territory, which creates the economic incentive to adopt CHP systems.

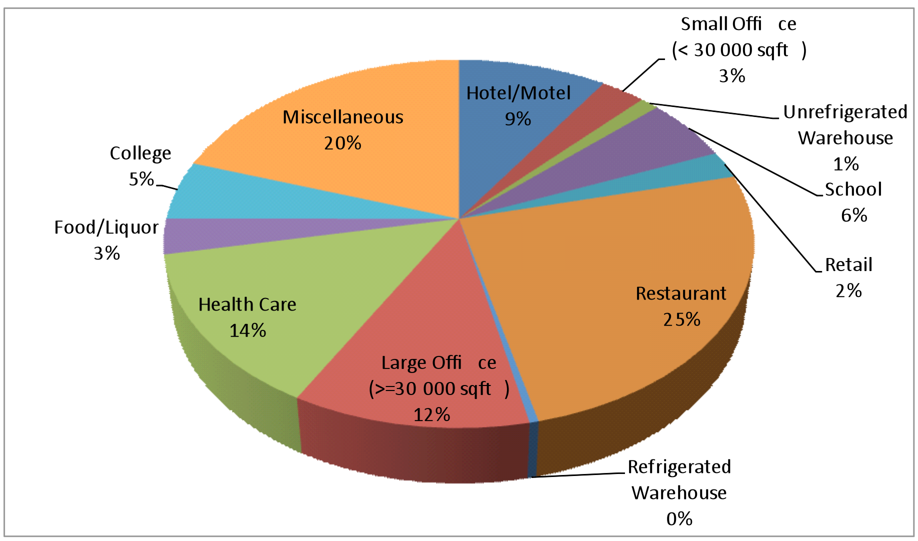
More information about the 13 end-uses and as well as used building types can be found at CEUS and Stadler et al. 2010.

Figure 4. Electricity Use by Building Type[12]



Source: CEUS and LBNL calculations

Figure 5. Natural Gas Use by Building Type[13]



Source: CEUS and LBNL calculations

Figure 6. Hourly July Load Profile for a Health Care Facility in San Diego

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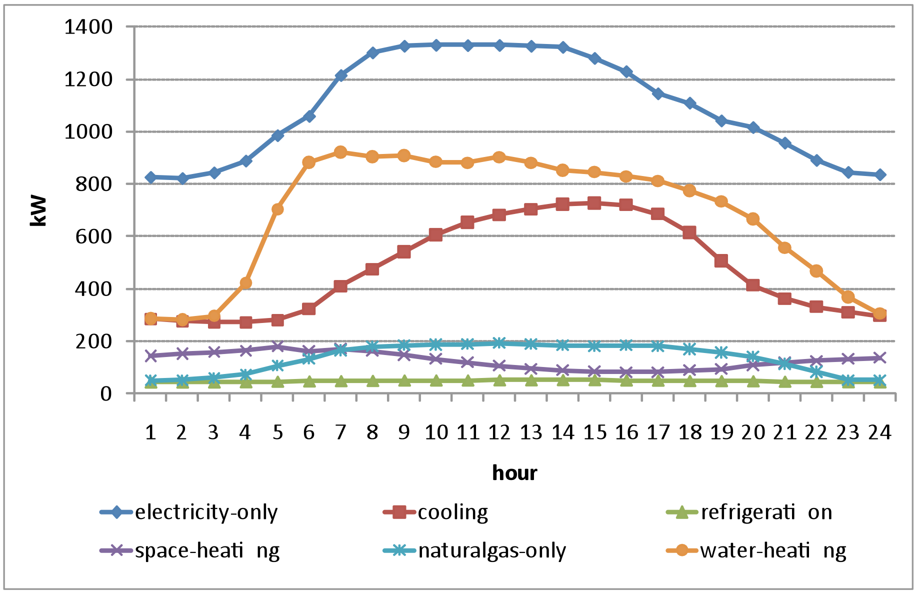
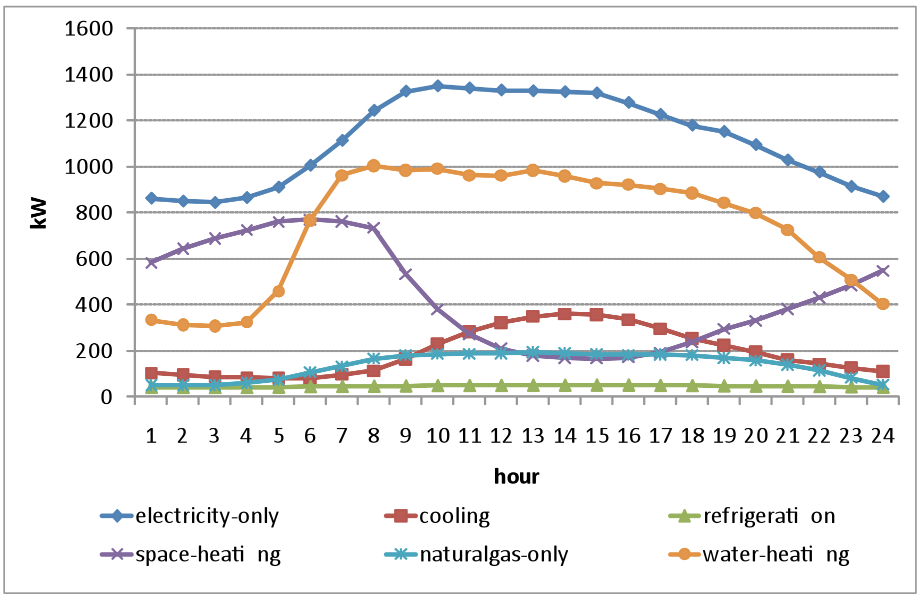
[12] The miscellaneous building type is not considered in this study.

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



Source: CEUS and LBNL calculations

Figure 7. Hourly December Load Profile for a Health Care Facility in San Diego

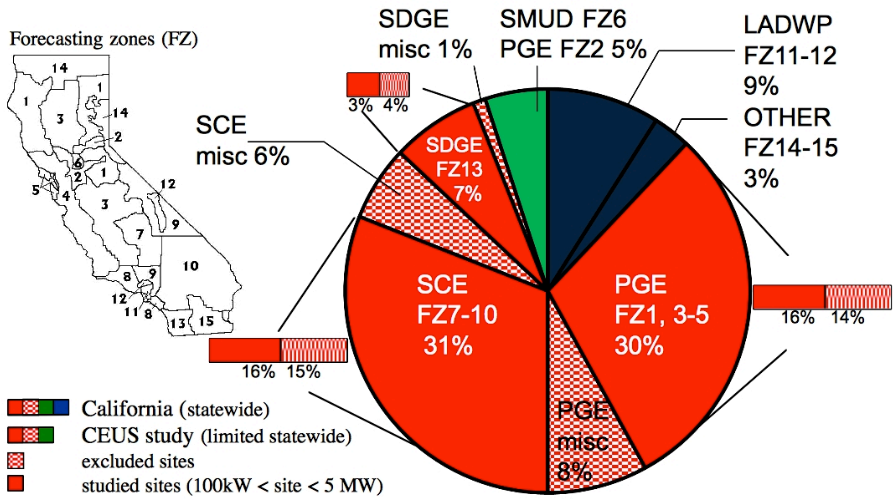


Source: CEUS and LBNL calculations

As can been seen from Figure 8, 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 PG&E, SCE, and SDG&E (see

CEUS database). As can be seen from Figure 8, PG&E service territory is composed by FZ1, 3, 4, and 5, SCE territory by FZ7 to 10, and SDG&E by FZ13.

Figure 8. Commercial Electric Demand Fractions



3.2. Used Utility Tariffs in 2020

As it 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/month 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):

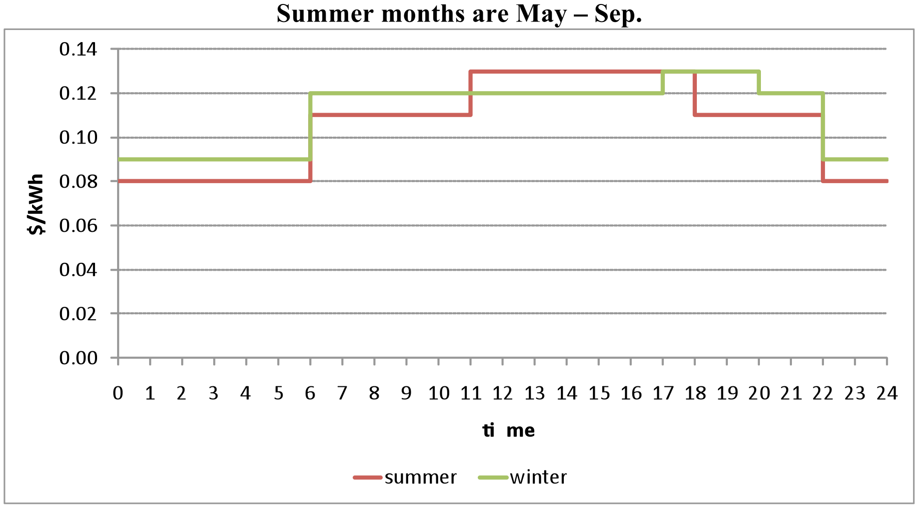
- electric peak load 0 – 199 kW: flat tariff A-1, no demand charge, seasonal difference between winter and summer months is a factor of 1.45;
- electric peak load 200 kW – 499 kW: TOU tariff A-10, seasonal demand charge; and
- electric peak load 500 kW and above: TOU tariff E-19, seasonal demand charge.

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.

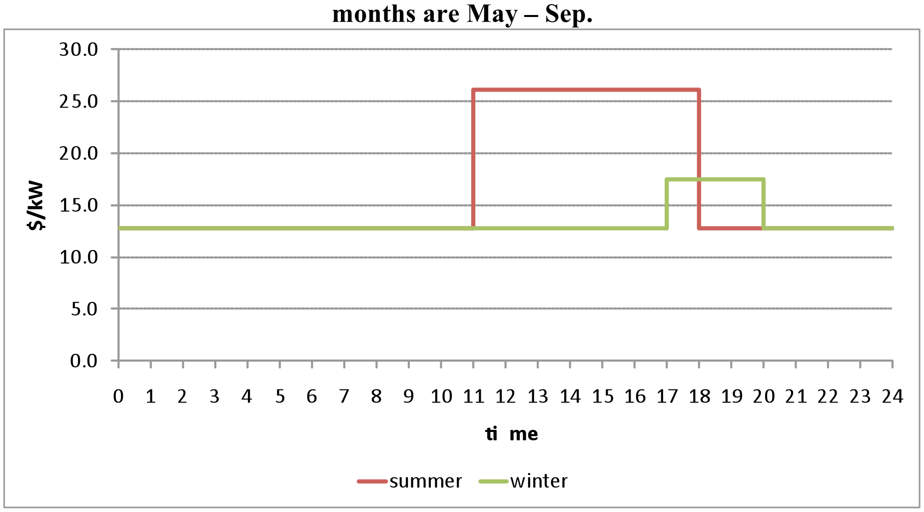
For SDG&E service territory two similar tariffs are used, which are just distinguished by the monthly fixed costs. Buildings with an electric peak load above 500 kW pay $233/month compared to $58/month for electric peak loads less than 500 kW (SDG&E Tariffs 2009).

Figure 9. Applied 2020 SDG&E Commercial Sector Electricity Prices, Electricity Component ($/kWh). Summer months are May – Sep.



Source: SDG&E Tariffs 2009

Figure 10. Applied 2020 SDG&E Commercial Sector Electricity Prices, Demand Charges ($/kW). Summer months are May – Sep.

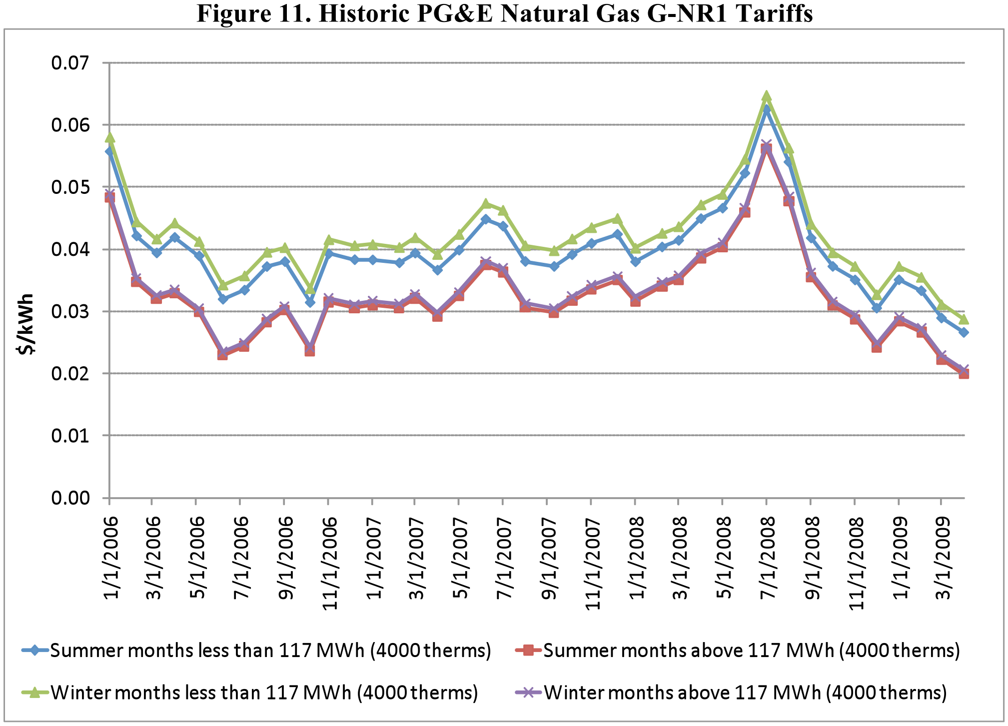


Source: SDG&E Tariffs 2009

3.3. Estimated Natural Gas Prices in 2020

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 it 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 11). Based on that observation, the average natural gas price between January 2006 and March 2009 was used as an estimate for 2020 and this delivers the natural gas prices for the three major service territories (see Table 1).

Figure 11. Historic PG&E Natural Gas G-NR1 Tariffs



Source: PG&E G-NR1 and LBNL calculations

The marginal macrogrid CO_2 emission rates in 2020 were gathered from Mahone et al. 2008 and do not show much hourly deviation around the average number of 0.51kgCO_2/kWh.

The solar data necessary for PV and solar thermal simulation were gathered from NREL's PVWATTS database.

Table 1. Applied 2020 Commercial Sector Natural Gas Prices

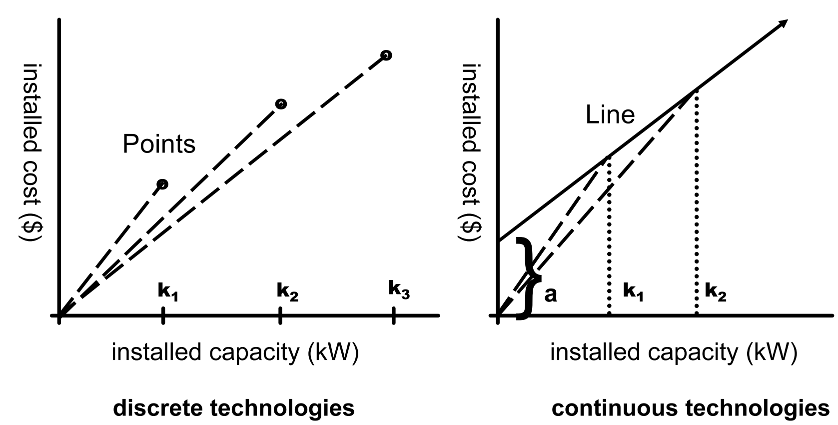
	Natural Gas		
	PG&E	SCE	SDG&E
US$/kWh	0.04	0.03	0.03
fixed (US$/month)	64.48	14.79	112.18/11.22[14]

Source: PG&E, SCE, SDG&E Tariffs and LBNL calculations

3.4. Estimated Technology Costs and Performance in 2020

The menu of available equipment options, their cost and performance characteristics are shown in Table 2 and Table 3. 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 size. Please note that both continuous and discrete technologies exhibit economies of scale, but the discrete ones can be more complex and dramatic. 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 12. 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 12. Discrete versus Continuous Technologies



[14] 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 2. Menu of Available Equipment Options in 2020, Continuous Investments[15]

	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[16]	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 3. Menu of Available Equipment Options in 2020, Discrete Investments[17]

	capacity (kW)	installed costs (US$/kW)	installed costs with heat recovery (US$/kW)	Variable maintenance (US$/kWh)	electric efficiency (%), (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[18]	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

4. Results for 2020

By using data and assumptions from the previous section and performing 1250 single DER-CAM runs in pure cost minimization mode[19] we find the results for five major scenarios. The five runs are the

[15] All cost data are expressed in 2008 US$.

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

[17] 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.

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

- base scenario, run 1, which does not consider any FiT or CO_2 pricing scheme
- FiT scenario, run 2, which applies a FiT to all DER technologies. The sales price is exactly the purchase tariff and the customer cannot be a net exporter of electricity
- CO_2 price scenario with \$40/tCO_2, run 3
- CO_2 price scenario with \$123/tCO_2, run 4, and
- CO_2 price scenario with \$273/tCO_2, run 5.

Please note that for every scenario a reference case, the no-invest case, was determined to be able to assess the five DER invest results.

For run 1 we find that fossil based internal combustion engines (ICE) with heat exchanger (HX) constitute the majority of adopted technologies in the base case without any CO_2 pricing scheme or feed-in tariff (FiT). Only 30.3 MW of fuel cell (FC) capacity is adopted in PG&E service territory in this base case (see Table 4, run 1). Almost all adopted absorption cooling capacity can be found in SDG&E service territory, which offsets 350 GWh of electricity demand. In general, SDG&E service territory seems to be very attractive for CHP. This attractiveness can be seen also in the energy cost reduction due to DER adoption. SDG&E commercial customers save almost 18% in annual energy costs, compared to the no-invest case in which all energy is purchased from the utility. Please note that the annual energy costs also include annualized capital costs for DER investments. Since CHP is an efficiency measure, which increases the overall system efficiency due to waste heat utilization, SDG&E service territory shows also the highest CO_2 reduction potential of 13% in this base case. Finally, the assumed costs for heat and electric storage systems prevent any adoption of storage systems and this situation is not changed by any CO_2 price or FiT.

By applying a FiT or net metering approach to all DER technologies, PV adoption increases, but only in the PG&E service territory (see run 2, from Table 4). The general attractiveness of CHP systems in the SDG&E region is amplified by the FiT and this reduces the adopted PV capacity from 73 MW to 61 MW. The adopted ICE-HX capacity increases by 17% compared to the base case run 1 in return. Because of this high penetration of ICEs and reduction in PV systems, the CO_2 reduction is only 7% compared to the no-invest reference case. The FiT, also applied to ICEs and FCs, creates the problem that not all heat can be utilized since not enough heat sinks exist at the local site. In other words, in the base case run 1 the adopted CHP system and electricity production are set up in a way that most of the heat can be used in heating or absorption cooling systems. However, as soon as the CHP system is allowed to sell electricity, it will be oversized and some heat will be wasted, and this reduces the overall system efficiency and increases the CO_2 emissions. The increased PV penetration for PG&E zones of 355 MW compensates for the high ICE adoption and slightly increases the CO_2 reduction to 8.8%. However, the second highest total CA CHP adoption of 1467 MW can be found in this FiT run. The CO_2 situation would change if the ICEs would be replaced by more electrically efficient FCs. Since FCs have a higher electrical efficiency, less heat is produced and this reduces the problem of heat dumping as described before. This means that a FiT can be CO_2 effective only if efficient FCs are adopted[20] (Stadler et al. 2010).

[19] This means any investment in DER must result in lower energy costs as in the no-invest case.

[20] Please note that this assessment depends on the macrogrid efficiency. In this work, we assume a macrogrid efficiency of 34%, which is higher than the electric efficiency of ICEs and lower than the electric efficiency of FCs.

Table 4. Regional Results for the Base Case and FiT Case

no-invest	reference case			reference case		
	PG&E	**SCE**	**SDG&E**	**PG&E**	**SCE**	**SDG&E**
total annual energy costs (M$)	2206.0	2097.0	728.2	2206.0	2097.0	728.2
total annual CO_2 emissions (ktCO2/a)	8094.1	9002.6	2607.1	8094.1	9002.6	2607.1
invest	**run 1, base case (no CO_2 price and feed-in tariff)**			**run 2, FiT for all DER**		
	PG&E	**SCE**	**SDG&E**	**PG&E**	**SCE**	**SDG&E**
adopted PV (MW)	102.0	7.9	73.0	355.4	7.9	60.6
adopted FC with HX (MW)	30.3	0.0	0.0	0.0	0.0	0.0
adopted ICE with HX (MW)	358.2	491.5	462.4	421.6	504.3	541.3
adopted lead acid batteries (MWh)	0.0	0.0	0.0	0.0	0.0	0.0
adopted solar thermal (MW)	260.1	152.5	3.2	236.5	152.5	1.7
adopted heat storage (MWh)	0.0	0.0	0.0	0.0	0.0	0.0
electricity provided by DER without PV (GWh)	2169.5	2014.9	3043.5	2210.6	1919.7	3387.7
cooling offset due to absorption chillers (GWh)	0.0	0.9	349.9	0.0	0.8	399.8
total annual energy costs (M$)	2164.9	2079.3	598.9	2153.6	2079.2	595.2
annual energy cost savings compared to the no-invest case (M$)	41.1	17.3	129.3	52.4	17.4	133.0
annual energy cost savings compared to the no-invest case (%)	1.9	0.8	17.8	2.4	0.8	18.3
total annual CO_2 emissions (ktCO2/a)[21]	7478.3	8656.0	2256.7	7380.6	8693.9	2413.5
annual total CO_2 emission reduction compared to the no-invest case ($ktCO_2/a$)	615.7	346.6	350.4	713.5	308.8	193.6
annual total CO_2 emission reduction compared to the no-invest case (%)	7.6	3.8	13.4	8.8	3.4	7.4

By applying three different CO_2 price levels we obtain the results in Table 5, which show that fossil based CHP systems are a very stable solution. Even in cases with extreme CO_2 prices of \$273/tCO$_2$ (\$1000/tC), 1519 MW of CHP is adopted in CA's commercial buildings, which is the highest total CA CHP adoption of all five cases in this paper. With increasing CO_2 prices more efficient FCs are adopted and the CHP capacity, which is the sum of ICE-HX and FC-HX, is in all three CO_2 pricing cases higher than in the base case run 1 form Table 4. It needs to be pointed out that there is competition between PV/solar thermal and FC systems since FC adoption is increasing with the CO_2 price.

[21] CO_2 emissions at the site, does not contain CO_2 offset due to electricity sales.

Due to the applied CO_2 price, PV and solar thermal adoption increases in all three service territories. However, one important finding for SDG&E regarding absorption cooling is that solar cooling is not a viable option since almost all cooling offset due to absorption chillers is removed in the very high CO_2 price case of $273/t$CO_2$. The higher solar thermal penetration does not directly support absorption cooling.

Table 5. Regional Results for the CO2 Pricing Scheme

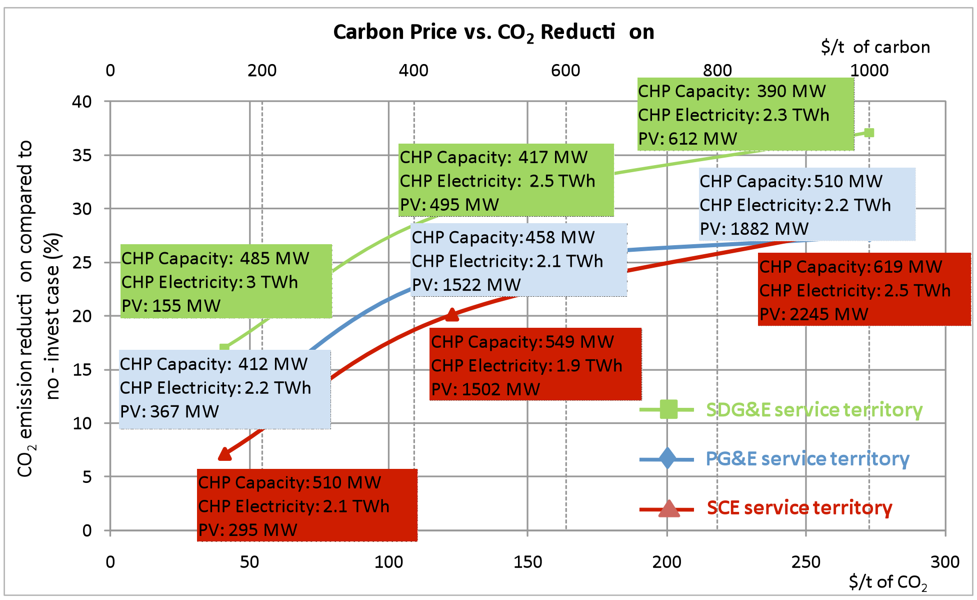
no-invest	reference case			reference case			reference case		
	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
total annual energy costs (M$)	2537.3	2465.1	835.0	3199.4	3201.5	1048.2	4414.9	4553.5	1438.7
total annual CO_2 emissions (ktCO_2/a)*	8094.1	9002.6	2607.1	8094.1	9002.6	2607.1	8094.1	9002.6	2607.1
invest	run 3, CO_2 price of $40/t$CO_2$			run 4, CO_2 price of $123/t$CO_2$			run 5, CO_2 price of $273/t$CO_2$		
	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
adopted PV (MW)	366.5	294.5	154.6	1522.2	1502.1	495.0	1882.4	2244.8	611.5
adopted FC with HX (MW)	30.3	0.0	18.2	48.2	0.0	62.9	205.8	307.9	332.9
adopted ICE with HX (MW)	381.7	509.8	467.0	437.0	548.5	354.3	303.3	311.0	58.0
adopted lead acid batteries (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
adopted solar thermal (MW)	309.7	185.0	7.9	564.0	304.7	76.7	685.5	443.3	142.0
adopted heat storage (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
electricity provided by DER without PV (GWh)	2178.2	2054.5	3031.1	2053.5	1939.1	2456.2	2198.0	2498.2	2349.4
cooling offset due to absorption chillers (GWh)	0.0	0.0	357.8	8.5	0.0	195.9	0.0	0.0	67.0
total annual energy costs (M$)	2462.7	2422.8	689.0	2982.7	3040.9	862.2	3889.2	4046.4	1132.6
annual energy cost savings compared to the no-invest case (M$)	74.6	42.3	145.9	216.7	160.5	186.0	525.8	507.1	307.1
annual energy cost savings compared to the no-invest case (%)	2.9	1.7	17.5	6.8	5.0	17.7	11.9	11.1	31.3
total annual CO_2 emissions (ktCO_2/a)*	7227.9	8366.6	2163.3	6169.4	7196.3	1830.4	5870.5	6435.9	1639.0
annual total CO_2 emission reduction compared to the no-invest case (ktCO_2/a)	866.2	636.0	443.8	1924.7	1806.3	776.6	2223.6	2566.8	968.1
annual total CO_2 emission reduction compared to the no-invest case (%)	10.7	7.1	17.0	23.8	20.1	29.8	27.5	28.5	37.1

Depending on the CO_2 price, DER and CHP adoption can contribute between 1.95 Mt/a and 5.75 Mt/a to GHG abatement in this mid-size commercial sector segment.

Also, SDG&E customers always save the most by adopting DER and the annual energy bill savings are always the biggest. SCE is always the least attractive service territory in terms of cost savings from DER adoption (see fourth row from the bottom in Table 4 and Table 5).

Figure 13 shows the CO_2 reduction compared to the no-invest case. 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[22]. However, most interesting is the fact that CHP adoption also increases with increasing CO_2 prices for PG&E as well as SCE regions. As shown in Table 5, more and more efficient FCs are adopted with increasing CO_2 prices. Also, since CHP is an efficiency measure the adopted capacity also increases and can reach overall efficiency levels of 80%. The electricity produced by CHP systems is only slightly reduced by medium-high CO_2 prices of \$123t/CO_2 compared to moderate CO_2 prices of \$40/t/CO_2. With very high CO_2 prices the CHP electricity supply for PG&E and SCE is even higher as in the moderate CO_2 price case. These results just underscore the efficiency increase obtained from FC adoption.

Figure 13. The Influence of a CO_2 Pricing Scheme on CHP/PV adoption and CO_2 emissions



Since we are most interested in the impact of a CO_2 price on DER adoption, we show CO_2 specific results for run 3 from Table 5. Figure 14 and Figure 15 show the importance of the SDG&E service territory again. In the moderate CO_2 price case of \$40/tCO_2, SDG&E customers can reduce their energy costs by 146 M\$ and bring the costs down to 689 M\$. This represents a cost reduction of roughly 18% compared to the no-invest 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 0.44 Mt/a, which represents a 17% CO_2 reduction compared to the no-invest case.

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

SCE is the least attractive utility territory for CHP adoption in relative terms. In absolute terms the highest CO_2 reduction of 866 Mt/a can be achieved in PG&E service territory.

Figure 14. Total Cost Reductions for DER Adopters for the three Different Utilities, Run 3, CO_2 Price of $40/tCO$_2$

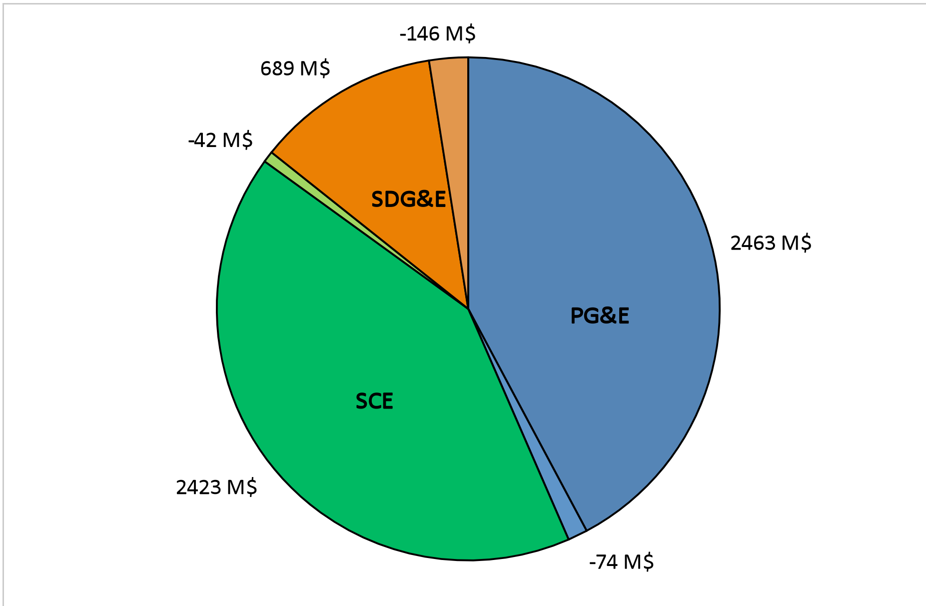
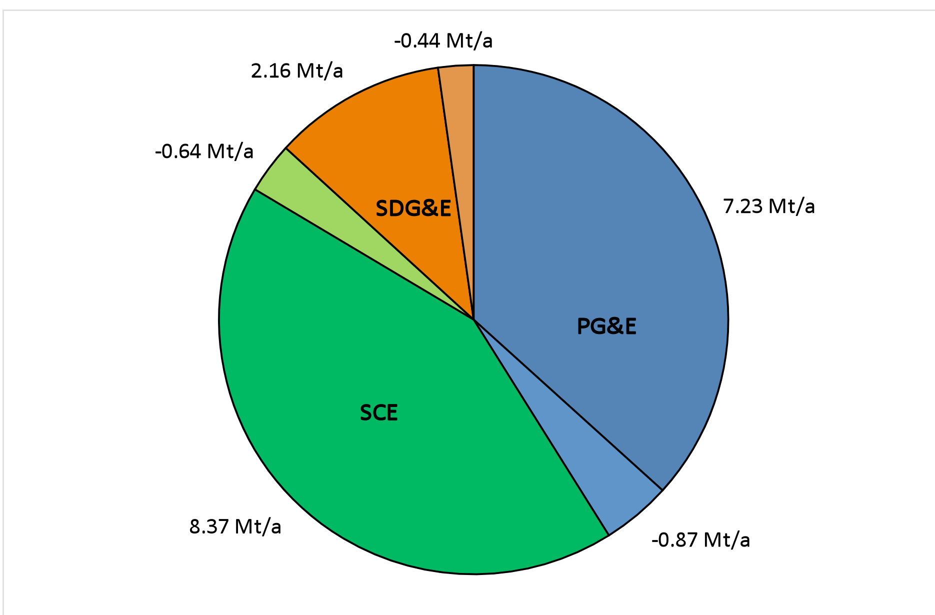


Figure 15. Total CO_2 Reductions for DER Adopters for the three Different Utilities, Run 3, CO_2 Price of $40/tCO$_2$



Finally, we show SDG&E building specific results for a CO_2 price of \$40/tCO_2 to emphasize the different DER attractiveness for different building types. The blue bars in Figure 16 show the costs for the buildings with DER adoption and the red bar show the costs savings compared to the no-invest case. Large office (LOFF), health care/hospital (HLTH), college (COLL) and lodging (LODG) buildings are very attractive hosts for DER. The same building types that are cost attractive also deliver the biggest GHG abatement potential (see Figure 17) and both Figures together show that large offices, health care facilities, colleges, and hotels/motels should be considered as prime candidates for CHP adoption.

Figure 16. Best Buildings in Terms of Cost Saving for SDG&E Service Territory, Run 3, CO_2 Price of $40/t$CO_2$

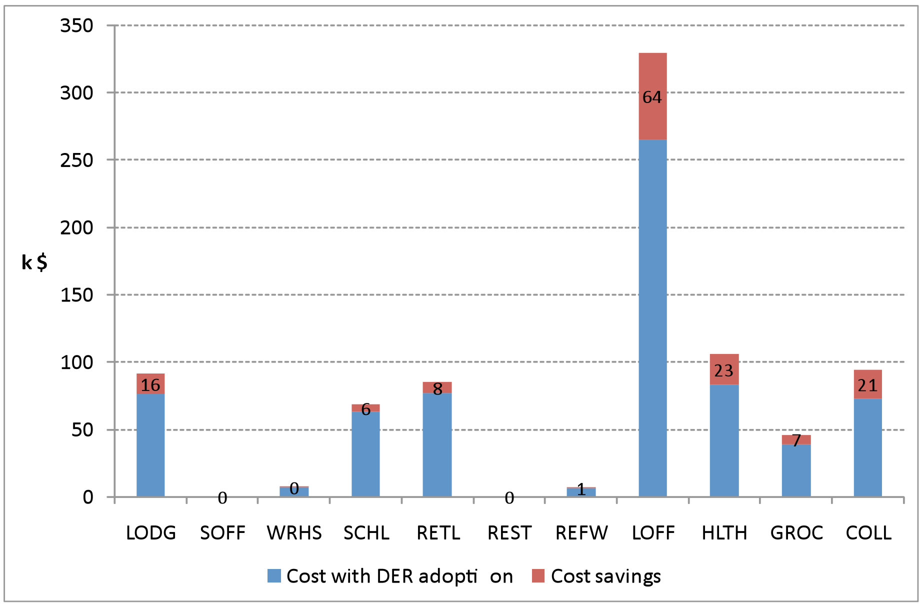
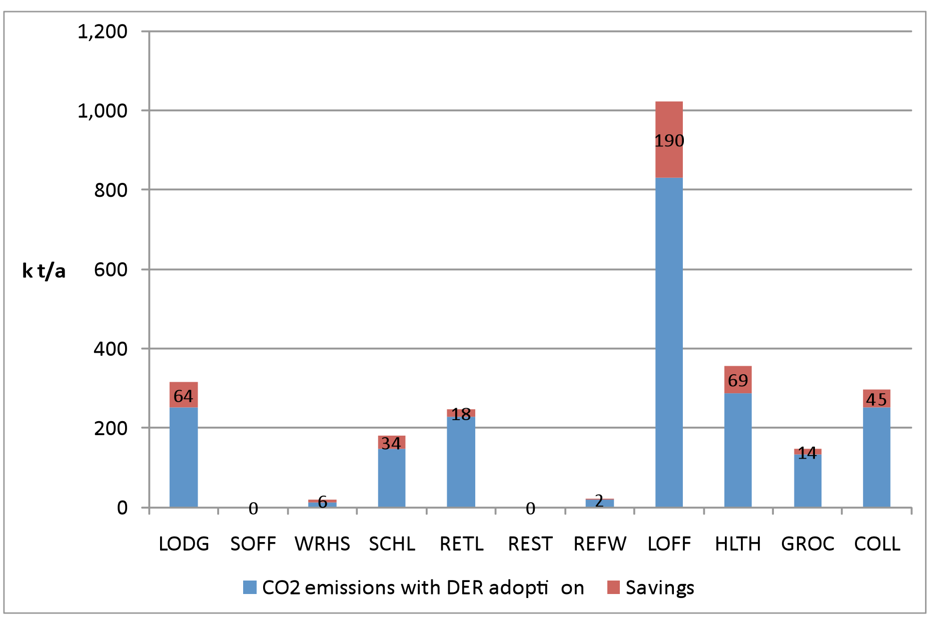


Figure 17. Building Type Specific CO_2 Savings for SDG&E Service Territory, Run 3, CO_2 Price of $40/t$CO_2$



5. Conclusions

This paper looks into the potential role of medium-sized commercial building CHP-enabled DG in GHG reduction. Two major policies, a FiT and a CO_2 pricing scheme, are applied to 138 representative commercial buildings in CA. By using utility tariff forecasts for PG&E, SCE, and SDG&E, combined with DER performance expectations for 2020, DER-CAM finds the cost optimal technology portfolio and delivers the GHG abatement potential. It is found that a FiT, applied to all DER technologies, is not the most effective way to stimulate CHP adoption as well as CO_2 reduction. The highest CHP adoption of 1519 MW can be found in the case with a very high CO_2 price of $273/tCO2 ($1000/tC). This high CO_2 price favors the adoption of efficient FC and PV/solar thermal systems. The highest GHG abatement potential of 5.75 Mt/a can be found also in this high CO_2 price case. Furthermore, the results are very utility specific and SDG&E service territory seems to be a very attractive region for CHP-enabled DG and shows always the highest costs savings due DER adoption. The assumption that high CO_2 prices would eliminate fossil based CHP systems is wrong and large office buildings, health care facilities, colleges, and motels/hotels are very attractive sites for CHP-enabled DG systems.

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