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The CO_2 Reduction Potential of Combined Heat and Power in California's Commercial Buildings[1]

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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 plus a natural gas company, 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] The work described in this report was funded by the California Energy Commission, Public Interest Energy Research Program, under Work for Others Contract No. 500-07-043 and by the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

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 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 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 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 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. 2009 and Marnay et al. 2008). Based on the CEUS database, which contains 2790 premises, the role of DG and CHP in greenhouse gas (GHG) abatement is determined. Since it is computationally expensive to solve multiple buildings, 138 representative CA sites[2] 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. For this research, more than 25 sensitivity runs with different technology costs, tariffs, interest rates, incentive levels, etc. have been performed. 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. Consequently, the major results reported here are relative to CARB's goal of 4 MW of statewide incremental installed CHP capacity in 2020.

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 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,

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

[3] An end-use efficiency investment module is currently under development, but not considered in this paper (see also Stadler 2009b).

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 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 loads;
- 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;
- 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.

The outputs of DER-CAM include the optimal DG and 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 currently under development but not applied in this work is an 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 new module see 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.

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

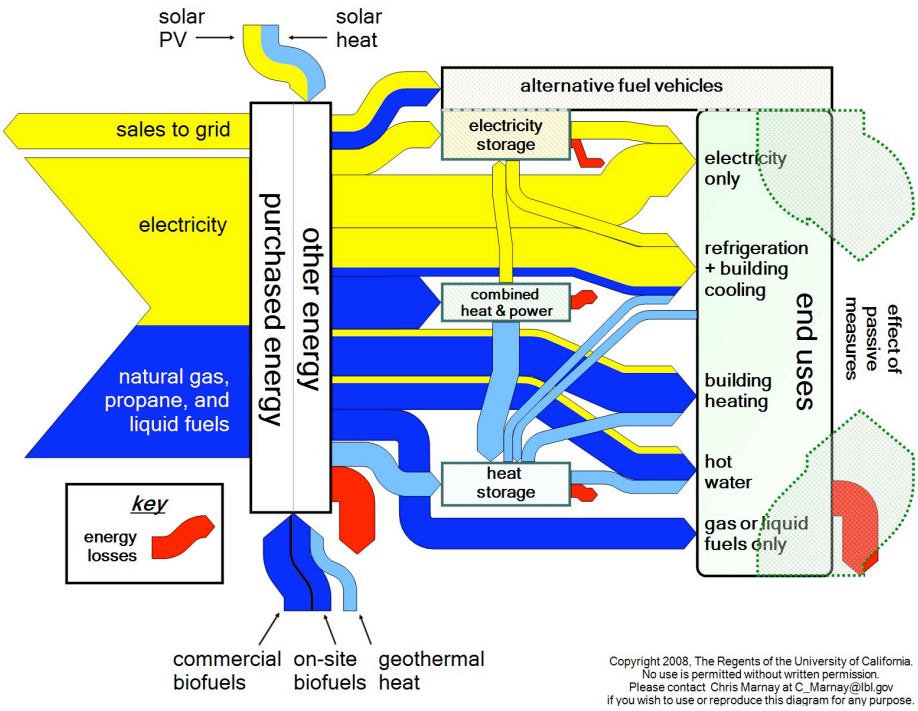
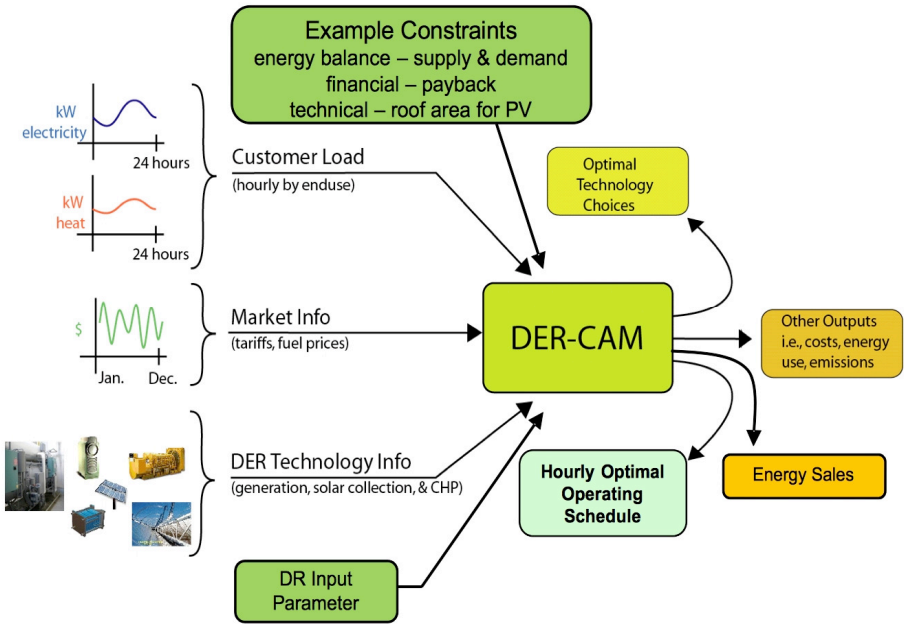


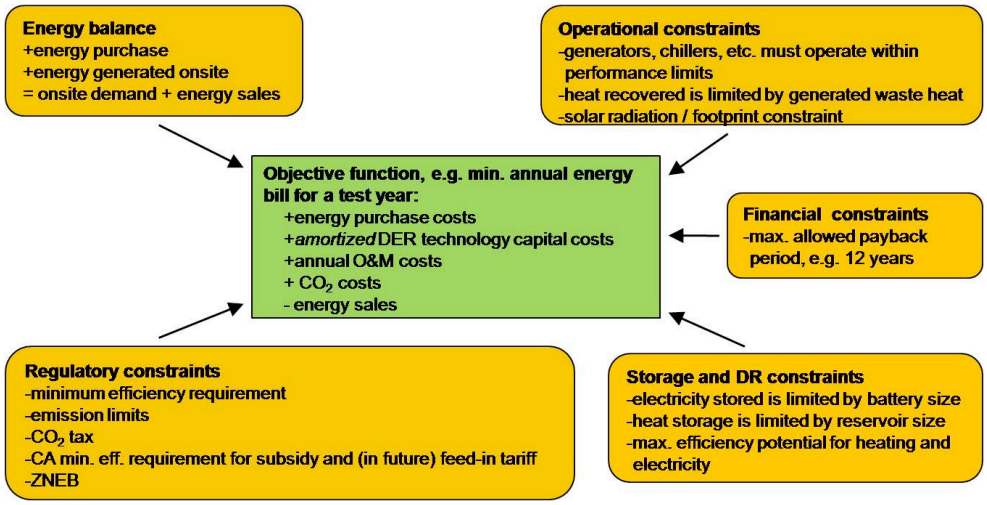
Figure 2. Schematic of Information Flow in DER-CAM



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. 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). For this study, the small zones FZ2, 14, and 15 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 we are only concerned with 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 also 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 Tables 1, 2, and 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. 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 is represented as a discrete technology, but batteries not so. A half of a 100 kW engine makes no

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

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

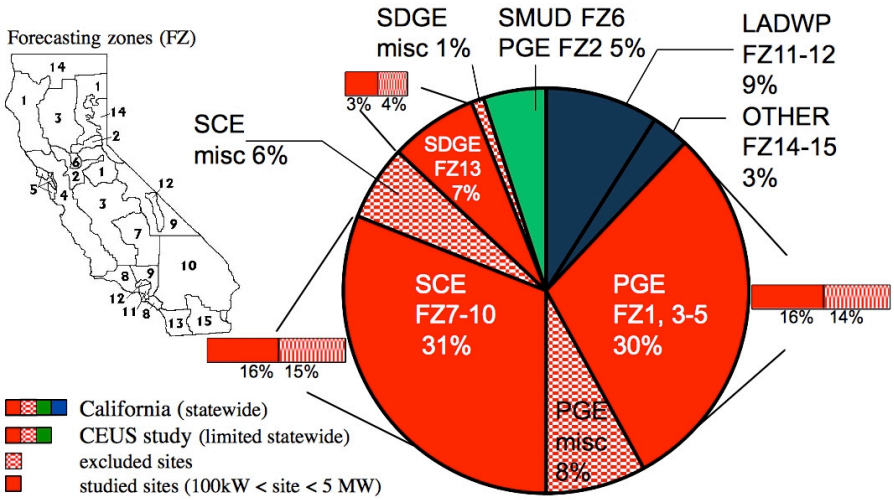


Figure 5. Discrete versus Continuous Technologies

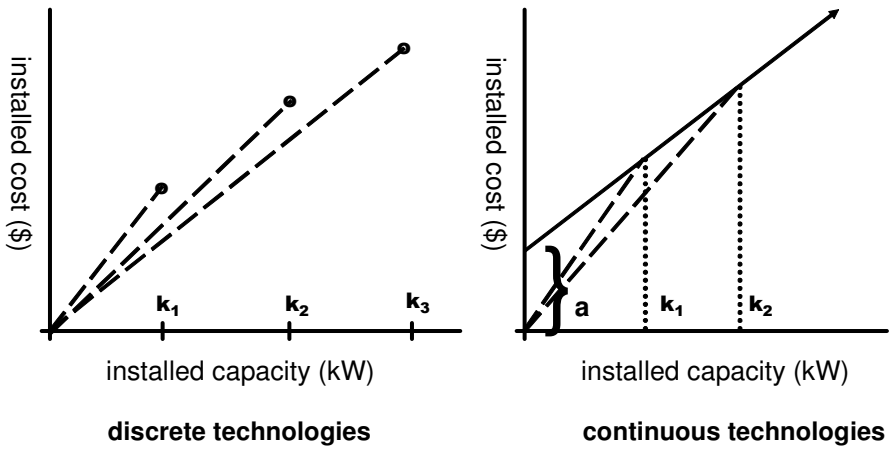


Table 1. Menu of Available Equipment Options in 2020, Continuous Investments

	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[6]	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[7]

	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[8]	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

As is typical for Californian utilities, the electricity tariff has a fairly small 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;

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

[7] 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.

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

- 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 is a significant determinant of technology choice and sizing of distributed generation and electric storage system installations (Stadler et al. 2008). 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):

- 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 also SCE GS-2, SCE TOU-GS-3, SCE TOU-8):

- electric peak load 20 – 200 kW: flat tariff GS-2, no demand charge, seasonal difference between winter and summer months is a factor of 1.1;
- electric peak load 200 kW – 500 kW: tariff TOU-GS-3, seasonal demand charge; and
- electric peak load 500 kW and above: tariff TOU-8, seasonal demand charge.

Table 3. Estimated SDG&E Commercial Sector Energy Prices in 2020

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[9]			

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

Natural Gas	
0.03	US$/kWh
112.18/ 11.22[10]	fixed (US$/month)

Source: SDG&E Tariffs and own calculations[11]

Please note that DG maintenance is not considered and 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 PVWATTS database.

[9] 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.

[10] 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.

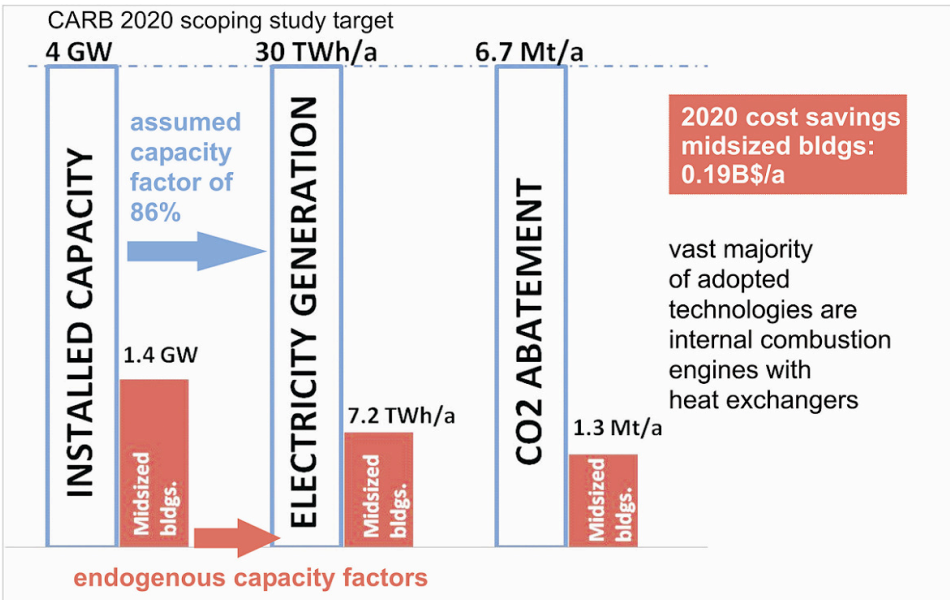
[11] For all runs the average natural gas price between 2006 and 2008 is used as estimate for 2020, and therefore, this also considers the spike in natural gas prices in 2008.

4. Major 2020 Results

Using data and assumptions described in the previous section, this study estimates that the mid-sized commercial building sector can install 1.4 GW of economic 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 fixed high capacity factor of 86%, which results in a 30 TWh/a goal[12]. 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 low 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 (ICE) with heat exchanger (HX) are a strongly dominant technology even in 2020. Please note that these calculations also consider solar thermal and PV, but they are mostly dominated by 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 or when they are in competition with PV and/or solar thermal during the day.

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



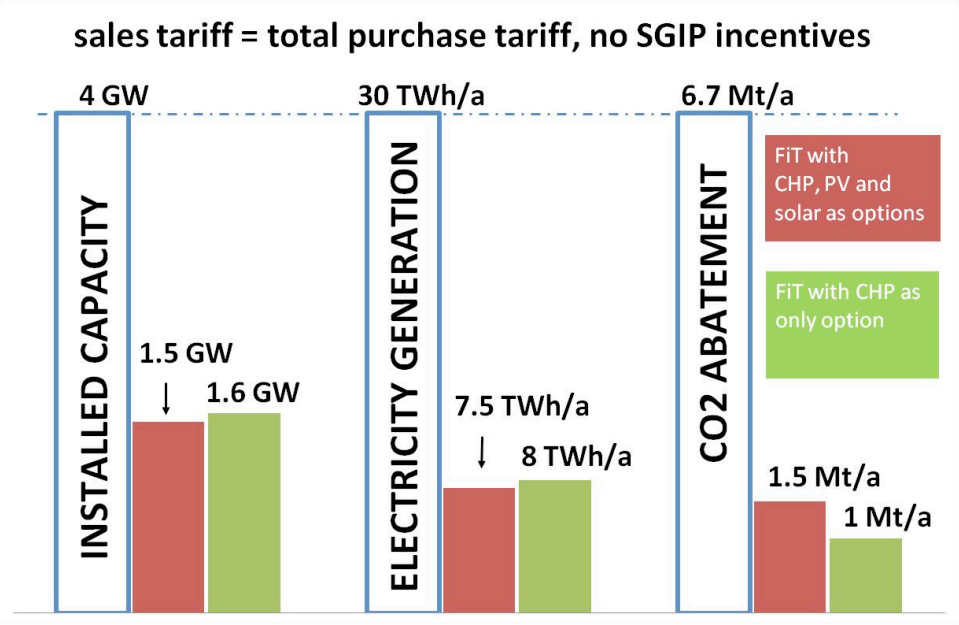
The impact of a CHP only feed-in tariff (FiT) is shown by the results of a second scenario presented in Figure 7. Assuming a FiT that allows sales back to the macrogrid of CHP generated power at a price slightly below the purchase price (pure net-metering) and without the Self Generation Incentive Program (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 ICE with HX 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 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, and yet carbon abatement is lower (green bar in Figure 7).

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

A third scenario 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 CO_2 result of Figure 7.

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 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.

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



A fourth scenario, considers the impact of a high investment subsidy of $1500/kW for fuel cells (FCs), which operate with an electric efficiency above the macrogrid efficiency.[13] 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. Please note that the installed PV capacity is reduced to 95 MW and the solar thermal capacity is reduced to 247 MW in this run.

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[14]. However, most interesting is the fact that CHP adoption also increases with increasing CO_2 prices (see red line in Figure 9). With increasing CO_2 prices more and more ICEs are replaced by efficient FCs. Also, since CHP is an efficiency measure the

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

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 $/tCO2.[15]

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

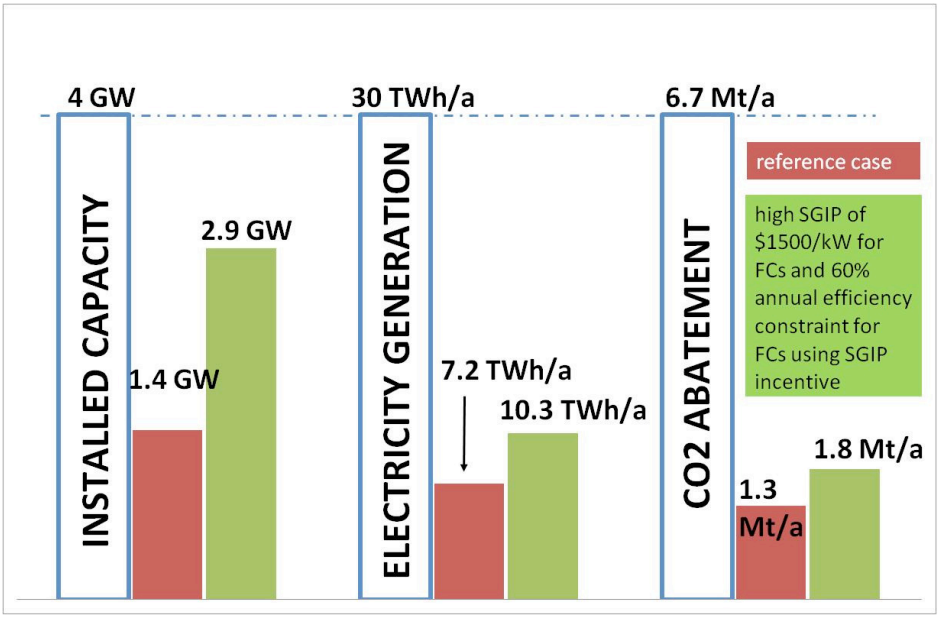
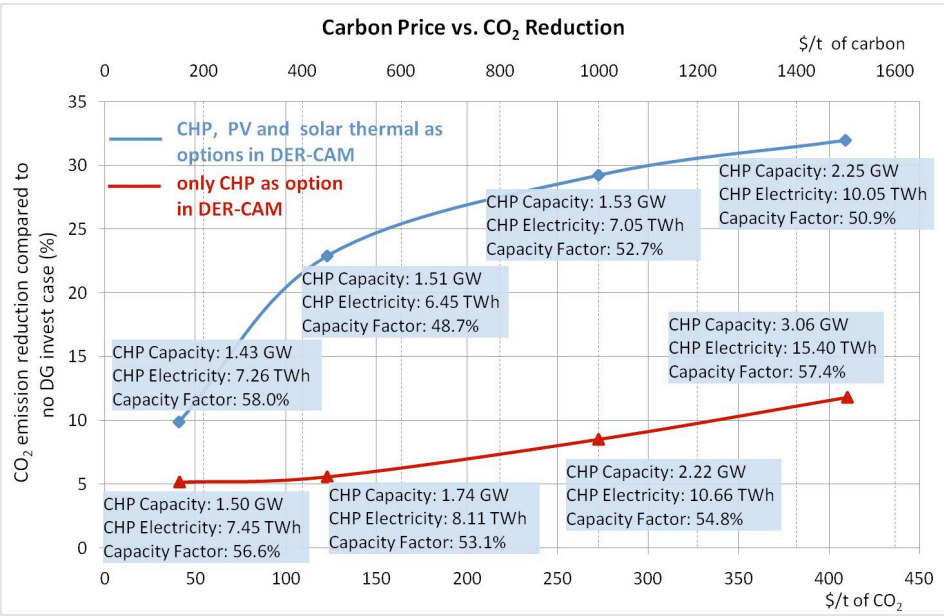


Figure 9. Influence of a CO_2 Pricing Scheme



A more detailed analysis of the reference case that adopts 1.4 GW of CHP capacities in 2020 can be found in Figures 10 and 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 new CHP capacity is added in SDG&E's FZ 13. The northern

[15] "tCO2" is equivalent to a metric ton of CO2.

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 FC 03 only adopts 25.8 MW of CHP by 2020, it delivers an impressive capacity factor of 75% followed by PG&E FZ 04 and SDG&E FZ13 (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, but that climate zone is very attractive.

Figure 10. Adopted CHP Capacities by Forecasting Zones (FZ) for the Reference Case

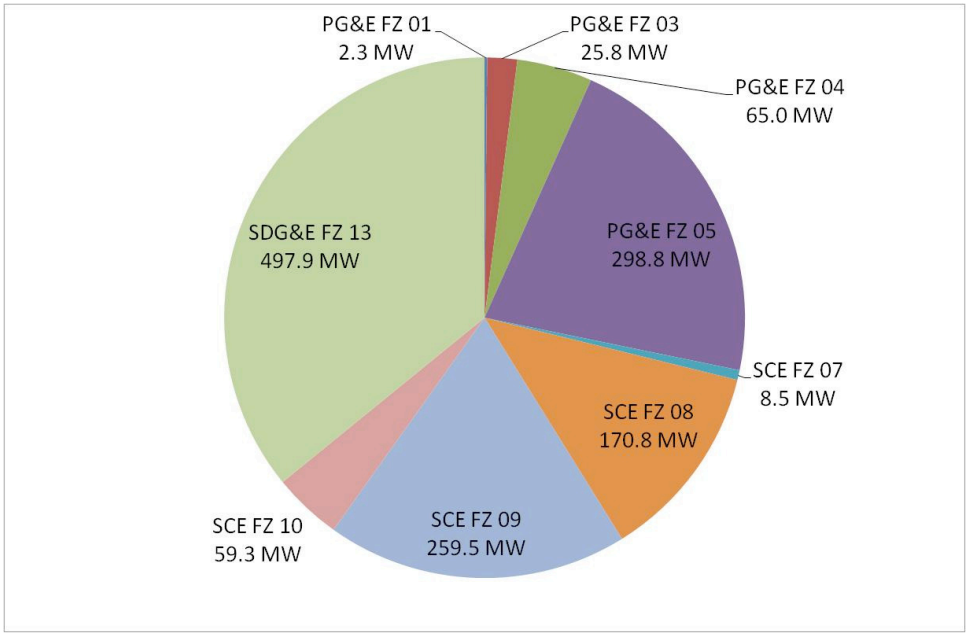


Figure 11. Electricity Generation from CHP by Forecasting Zones (FZ) for the Reference Case

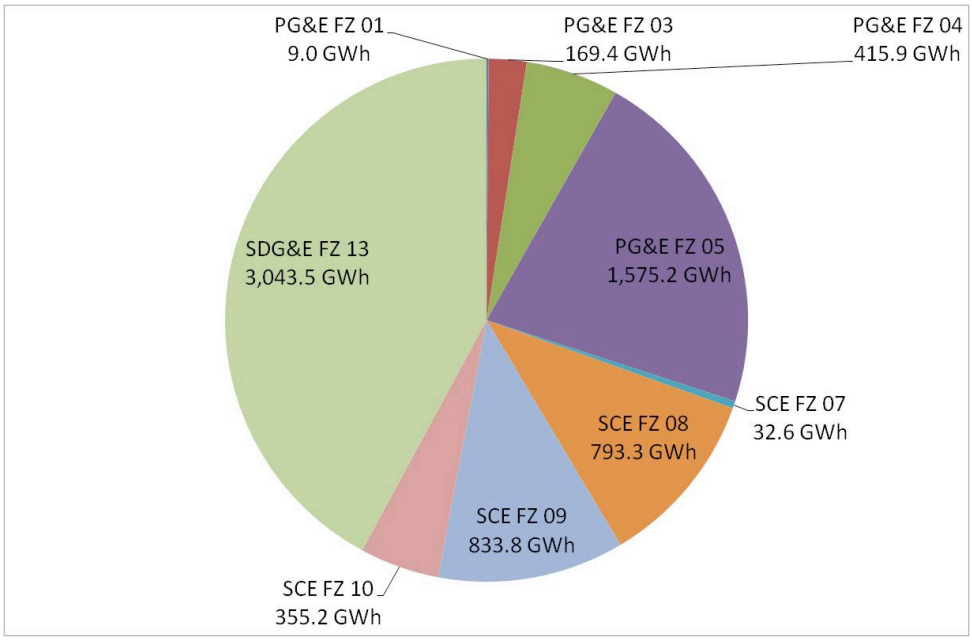


Figure 12. Capacity Factors for CHP by Forecasting Zones (FZ) for the Reference Case

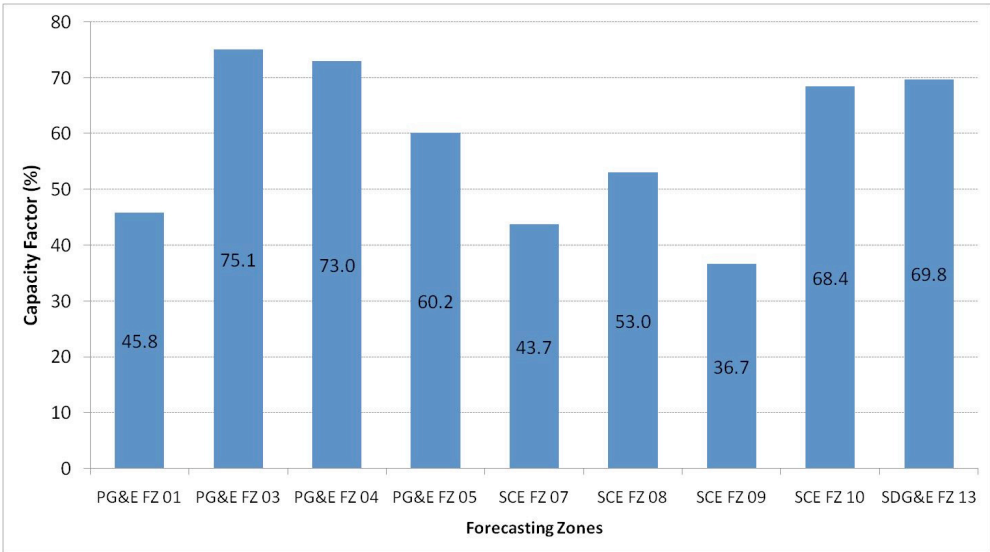
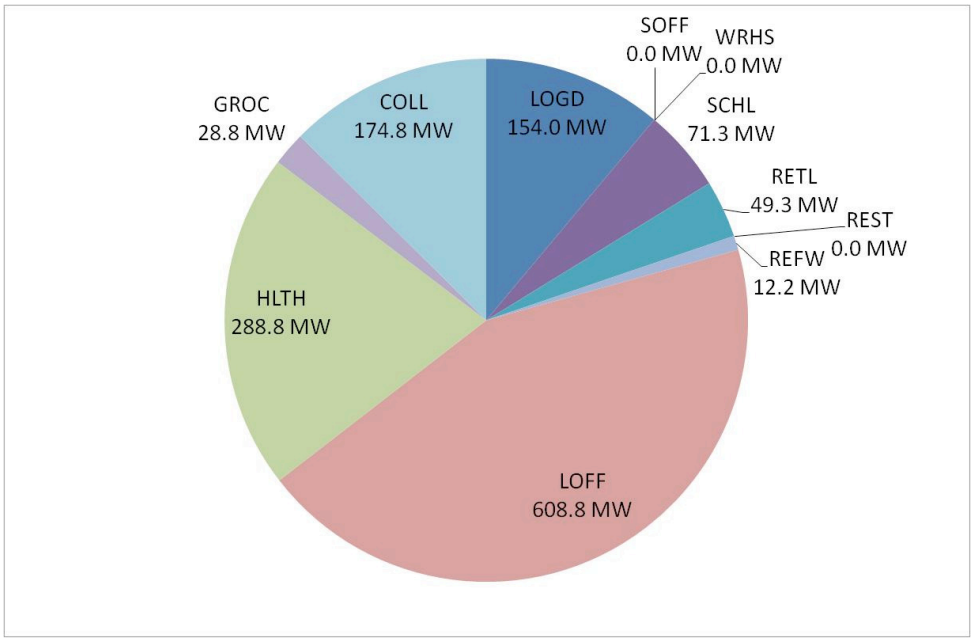


Figure 13. Adopted CHP Capacities by Building Types for the Reference Case[16]



In the final Figure 13, we show 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 market. Small offices (SOFF) and warehouses (WRHS) do not appear in the results of this study.

[16] SOFF: Small Office, WRHS: Warehouse, SCHL: School, RETL: Retail Store, REST: Restaurant, REFW: Refrigerated Warehouse, LOFF: Large Office, HLTH: Health Care, GROC: Grocery, COLL: College, LOGD: Lodging.

5. Conclusions

This study takes a look 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 a MILP 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 it is found by the MILP, 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 a promising hosts worthy of further study;
- overall the effect on CO_2 emissions is limited, never exceeding 27 % 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.

Only one restaurant was included among our 138 buildings, 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.

Finally, some caveats include that the representation of energy efficiency measures in DER-CAM is rudimentary and not used in this study. A significant effort to add efficiency and behavioral response as contributors towards meeting future energy services requirements is necessary and justified. Also, 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 paper.

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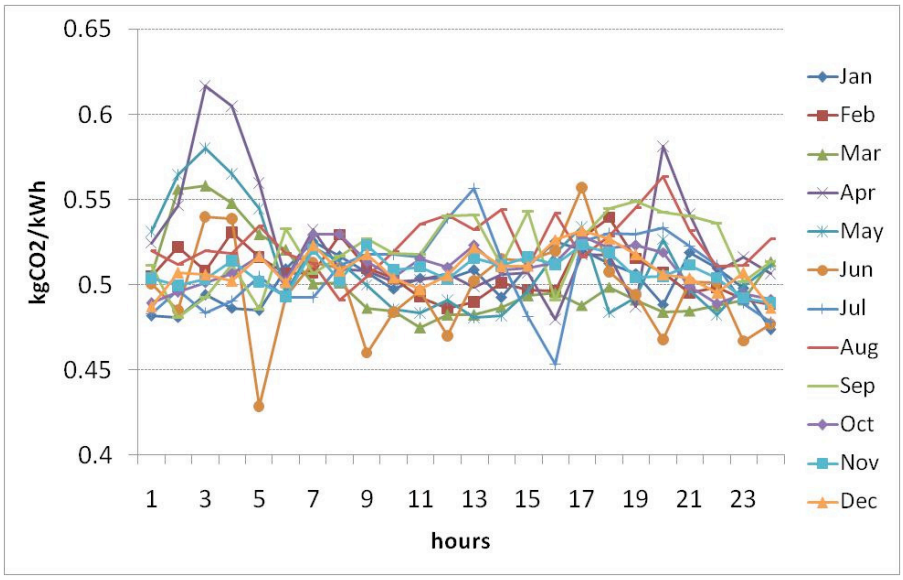
Appendix A: Hourly Marginal CO_2 Rates

Figure A1. Average Hourly Marginal Macrogrid CO_2 Rates in 2020



Source: Mahone et al. 2008 and LBNL calculations