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ASSESSMENT OF COMBINED HEAT AND POWER SYSTEM "PREMIUM POWER" APPLICATIONS IN CALIFORNIA

FINAL REPORT

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Final Project Report

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Table of Contents

Executive Summary iii
Introduction 1
The Pacific Region Combined Heat and Power Application Center 1
CHP Premium Power Applications and Opportunities 2
Modeling and DER-CAM Overview 2
Selected CHP Analysis Sites 5
Key Technical and Economic Modeling Assumptions 5
Model Data and Analysis Procedures 6
Summary of Modeling Results 7
Caveats and Directions for Future Work 11
Conclusions 12
References 14

Appendix A – Load Data and DER-CAM Inputs / Results for Each Scenario

Executive Summary

This “Assessment of Combined Heat and Power Premium Power Applications in California analyzes the current economic and environmental performance of combined heat and power (CHP) systems in power interruption intolerant commercial facilities. Through a series of three case studies, key trade-offs are analyzed with regard to the provision of black-out ridethrough capability with the CHP systems and the resutling ability to avoid the need for at least some diesel backup generator capacity located at the case study sites.

Each of the selected sites currently have a CHP or combined heating, cooling, and power (CCHP) system in addition to diesel backup generators. In all cases the CHP/CCHP system have a small fraction of the electrical capacity of the diesel generators. Although none of the selected sites currently have the ability to run the CHP systems as emergency backup power, all could be retrofitted to provide this blackout ride-through capability, and new CHP systems can be installed with this capability.

The following three sites/systems were used for this analysis:

<u>Sierra Nevada Brewery</u>
Using 1MW of installed Molten Carbonate Fuel Cells operating on a combination of digestor gas (from the beer brewing process) and natural gas, this facility can produce electricty and heat for the brewery and attached bottling plant. The major thermal load on-site is to keep the brewing tanks at appropriate temperatures.

<u>NetApp Data Center</u>
Using 1.125 MW of Hess Microgen natural gas fired reciprocating engine-generators, with exhaust gas and jacket water heat recovery attached to over 300 tons of of adsorption chillers, this combined cooling and power system provides electricity and cooling to a data center with a 1,200 kW peak electrical load.

<u>Kaiser Permanente Hayward Hospital</u>
With 180kW of Tecogen natural gas fired reciprocating engine-generators this CHP system generates steam for space heating, and hot water for a city hospital.

For all sites, similar assumptions are made about the economic and technological constraints of the power generation system. Using the Distributed Energy Resource Customer Adoption Model (DER-CAM) developed at the Lawrence Berkeley National Laboratory, we model three representative scenarios and find the optimal operation scheduling, yearly energy cost, and energy technology investments for each scenario below:

<u>Scenario 1</u>
Diesel generators and CHP/CCHP equipment as installed in the current facility. Scenario 1 represents a baseline forced investment in currently installed energy equipment.

<u>Scenario 2</u>
Existing CHP equipment installed with blackout ride-through capability to replace approximately the same capacity of diesel generators. In Scenario 2 the cost of the

replaced diesel units is saved, however additional capital cost for the controls and switchgear for blackout ride-through capability is necessary.

Scenario 3

Fully optimized site analysis, allowing DER-CAM to specify the number of diesel and CHP/CCHP units (with blackout ride-through capability) that should be installed ignoring any constraints on backup generation. Scenario 3 allows DER-CAM to optimize scheduling and number of generation units from the currently available technologies at a particular site.

The results of this analysis, using real data to model the optimal schedulding of hypothetical and actual CHP systems for a brewery, data center, and hospital, lead to some interesting conclusions. First, facilities with high heating loads will typically prove to be the most appropriate for CHP installation from a purely economic standpoint. Second, absorption/adsorption cooling systems may only be economically feasible if the technology for these chillers can increase above current best system efficiency. At a coefficient of performance (COP) of 0.8, for instance, an adsorption chiller paired with a natural gas generator with waste heat recovery at a facility with large cooling loads, like a data center, will cost no less on a yearly basis than purchasing electricity and natural gas directly from a utility.

Third, at marginal additional cost, if the reliability of CHP systems proves to be at least as high as diesel generators (which we expect to be the case), the CHP system could replace the diesel generator at little or no additional cost. This is true if the thermal to electric (relative) load of those facilities was already high enough to economically justify a CHP system. Last, in terms of greenhouse gas emissions, the modeled CHP and CCHP systems provide some degree of decreased emissions relative to systems with less CHP installed. The emission reduction can be up to 10% in the optimized case (Scenario 3) in the application with the highest relative thermal load, in this case the hospital.

Although these results should be qualified because they are only based on the three case studies, the general results and lessons learned are expected to be applicable across a broad range of potential and existing CCHP systems.

Introduction

This “Assessment of Combined Heat and Power Premium Power Applications in California” analyzes the prospects for combined heat and power (CHP) systems to provide high reliability power for customer sites, as well as improved energy efficiency and economic benefits. Through a series of three case studies, key trade-offs are analyzed with regard to the provision of black-out ridethrough capability with the CHP systems and the resutling ability to avoid the need for at least some diesel backup generator capacity located at the case study sites.

Each of the selected sites currently have a CHP or combined heating, cooling, and power (CCHP) system[1] in addition to diesel backup generators. In all cases the CHP/CCHP system have a small fraction of the electrical capacity of the diesel generators. Although none of the selected sites currently have the ability to run the CHP systems as emergency backup power, all could be retrofitted to provide this blackout ride-through capability, and new CHP systems can be installed with this capability.

This report presents the details of the analysis and the results, and finishes by drawing some general conclusions. First, the structure and of the Pacific Region Combined Heat and Power Application Center (PRAC) is briefly described.

The Pacific Region Combined Heat and Power Application Center

The Pacific Region Combined Heat and Power Application Center (PRAC) was established in 2003 to foster the development of CHP in the Pacific region and to address knowledge gaps and other market failures that may be preventing the optimal expansion of CHP in the region. The primary sponsors of the PRAC are the U.S. Department of Energy and the California Energy Commission.

The PRAC features a collaborative structure among UC Berkeley (UCB), UC Irvine (UCI), and San Diego State University (SDSU). Each university provides some unique capabilities and resources to the center. The primary groups involved on the three campuses are the Energy and Resources Group at UCB, the Advanced Power and Energy Program at UCI, and the Industrial Assessment Center at SDSU. The PRAC is led by three co-directors (Tim Lipman, UCB; Vince McDonell, UCI; Asfaw Beyene, SDSU) and two additional principal investigators (Dan Kammen, UCB; Scott Samuelsen, UCI). For more information on the activities of the PRAC, visit the following website: http://www.chpcenterpr.org.

The PRAC has established strategic alliances with key partners in the region. These include three groups that work closely with each “node” of the center -- the Lawrence Berkeley National Laboratory, Sempra Energy, and the California Center for Sustainable Energy (formerly known as the San Diego Regional Energy Office) – and various other groups that are involved less directly. These additional groups work collaboratively with the PRAC to leverage activities and expand the effectiveness of the centers operations.

[1] Most CCHP locations that are using waste heat for cooling also use some of the waste heat directly for water or space heating, at least during the cooler months when the cooling loads are lower. The NetApp data center is somewhat unusual in that all of the waste heat is used to drive the adsorption chillers, making it a "combined cooling and power" (CCP) application, rather than a more usual CCHP "trigeneration" system.

CHP Premium Power Applications and Opportunities

There is great deal of interest in redundant systems for distributed power generation in a number of industries where the cost of power and more importantly power interruptions is substantial. These so called *premium power* applications for CHP systems are the focus of this analysis. Some examples of such facilities are manufacturing plants, data centers, hospitals, and nursing homes. Premium power applications are characterized by their need for backup power in the event of a utility power outage. These backup systems are traditionally diesel generators and increasingly other CCHP systems are being installed at these sites. Such systems typically consist of on-site generation fueled by either natural gas or solar energy that produce electricity and supply thermal energy for cooling and heating loads. These CCHP systems can also act as backup generators in some cases, thus obviating the need for diesel backup generators. In this paper we analyze the economic feasibility of CCHP for premium power applications.

Modeling and DER-CAM Overview

For the purposes of this analysis we chose three sites with existing Combined Heat and Power (CHP) or Combined Cooling, Heating, and Power (CCHP) systems in place which also had diesel backup generators. As the basis for an economic analysis of these sites, we used the Distributed Energy Resources Customer Adoption Model (DER-CAM) being developed at the Lawrence Berkeley National Laboratory.

DER-CAM is an economic model of customer DER adoption implemented in the General Algebraic Modeling System (GAMS) optimization software. DER-CAM's goal is to minimize the cost of supplying electric and heat loads of a specific customer site by optimizing the installation and operation of distributed generation, combined heat and power, and thermally activated cooling equipment. In other words, the focus of this work is primarily economic. To achieve this objective, the following issues must be addressed:

- Which is the lowest-cost combination of distributed generation technologies that a specific customer can install?

- What is the appropriate level of installed capacity of these technologies that minimizes cost?

- How should the installed capacity be operated so as to minimize the total customer energy bill?

With the assumption that the customer desires to install distributed generation to minimize the cost of energy consumed on site, it is possible to determine the technologies and capacity the customer is likely to install and to predict when the customer will be self-generating electricity and/ or transacting with the power grid, and likewise when purchasing fuel or using recovered heat.

The DER-CAM model chooses which Distributed Generation (DG) and/or CHP technologies a customer should adopt and how that technology should be operated based on specific site load and price information, and performance data for available equipment options. The inputs to and outputs from DER-CAM are illustrated below.

Key inputs into the model are:

- the customer's end-use load profiles (typically for space heat, hot water, gas only, cooling, and electricity only)
- the customer's default electricity tariff, natural gas prices, and other relevant price data
- the capital, operating and maintenance (O&M), and fuel costs of the various available technologies, together with the interest rate on customer investment
- the basic physical characteristics of alternative generating, heat recovery and cooling technologies, including the thermal-electric ratio that determines how much residual heat is available as a function of generator electric output.

Outputs to be determined by the optimization model are:

- the capacities of DG and CHP technology or combination of technologies to be installed
- when and how much of the installed capacity will be running
- the total cost of supplying the electric and heat loads.

Key DER-CAM assumptions are:

- customer decisions are made based only on direct economic criteria (in other words, the only possible benefit is a reduction in the customer's energy bills);
- no deterioration in output or efficiency during the lifetime of the equipment is considered, and start-up and other ramping constraints are not included;
- reliability and power quality benefits, as well as economies of scale in O&M costs for multiple units of the same technology are not directly taken into account; and
- possible reliability or power quality improvements accruing to customers are not explicitly considered.

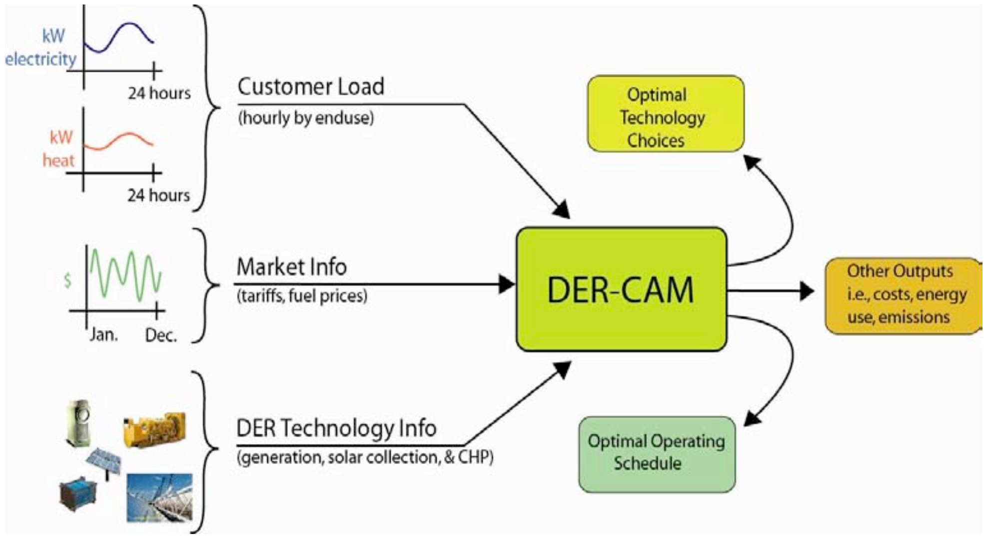

Figure 1: DER-CAM Structure [Stadler et al., 2008a]

We note that a more recent version of DER-CAM has been developed that includes consideration of reliability and power quality improvements and other benefits to the CHP or microgrid system host site. See Stadler et al. [2008b] for details.

<u>Simultaneous Optimization Approach</u>

The next figure shows a high-level schematic of the energy flow modeled in DER-CAM. Possible energy inputs to the site are solar insolation, utility electricity and natural gas. For a given DG investment decision, DER-CAM selects the optimal combination of utility purchase and on-site generation required to meet the site's end-use loads at each time step. The model allows that:

1) electricity-only loads (e.g. lighting and office equipment) can only be met by electricity;
2) cooling loads can be met either by electricity or by heat (via absorption / adsorption chiller);
3) hot water and space heating loads can be met either by recovered heat or by natural gas; and
4) natural gas-only loads (e.g. mostly cooking) can only be met by natural gas.

With these constraints, the model then attempts to find the best strategy for meeting the various energy needs at the lowest cost [Stadler et al., 2008a].

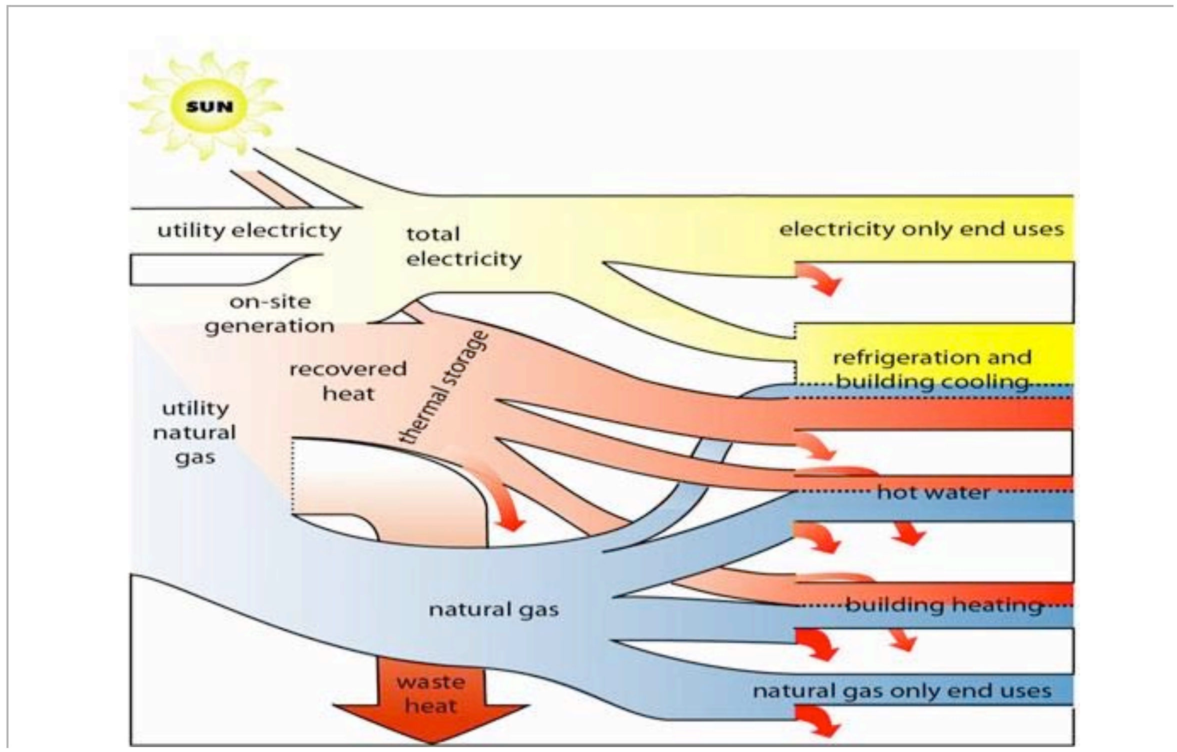

Figure 2 [Stadler et al., 2008a]

Selected CHP Analysis Sites

Each of the selected sites currently have a CHP or CCHP system in addition to diesel backup generators. In all cases the CHP/CCHP system have a small fraction of the electrical capacity of the diesel generators. Although none of the selected sites currently have the ability to run the CHP systems as emergency backup power, all could be retrofitted to provide this blackout ride-through capability, and new CCHP systems can be installed with this capability. The following three sites/systems were used for this analysis:

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With 180kW of Tecogen natural gas fired reciprocating engine-generators this CHP system generates steam for space heating, and hot water for a city hospital.

Key Technical and Economic Modeling Assumptions

For all sites, similar assumptions are made about the economic and technological constraints of the power generation system. Using DER-CAM, we model three representative scenarios and find the optimal operation scheduling, yearly energy cost, and energy technology investments for each scenario below:

Scenario 1
Diesel generators and CHP/CCHP equipment as installed in the current facility. Scenario 1 represents a baseline forced investment in currently installed energy equipment.

Scenario 2
Existing CHP equipment installed with blackout ride-through capability to replace approximately the same capacity of diesel generators. In scenario 2 the cost of the replaced diesel units is saved, however additional capital cost for the controls and switchgear for blackout ride-through capability is necessary.

Scenario 3
Fully optimized site analysis, allowing DER-CAM to specify the number of diesel and CHP/CCHP units (with blackout ride-through capability) that should be installed ignoring any constraints on backup generation. Scenario 3 allows DER-CAM to optimize scheduling and number of generation units from the currently available technologies at a particular site.

Hardware data sheets and historical load data, not building models, form the basis for demand at each site. Average weekend and weekday loads for each month are extrapolations of this data and input to DER-CAM. For all sites, 2006 load data is used when available, but due to inavalibility some 2007 and 2008 data is supplemented in the Kaiser and NetApp models to fill in the gaps in 2006 data. Weekday, weekend and seasonal loads are appropriately aligned in all sets of merged data from multiple years so that seasonal and weekly variations are properly reflected in the data input to DER-CAM (Appendix A contains load data).

Capital cost inputs for all CHP/CCHP equipment and diesel generators are based on actual costs of installation for Sierra Nevada and NetApp, ignoring any state or federal rebates or incentives. Both construction projects were completed within the last 4 years. Capital costs for the Kaiser facility is based on a quote for the average cost of a nearly equivalent system with modern equipment [Tecogen, 2008], owing to the older age of the Kaiser system. This quote also contains a comparison to a similar system installed with blackout ride-through capability, thus allowing easy comparison of the two configurations. Diesel generator equipment costs are also based on in industry price quote [Peterson Power, 2008]. Service contracts to determine variable and fixed O&M costs are either real costs or estimates from the contractors who installed the equipment.

In order to accurately model the yearly energy cost for each facility, a five percent interest rate is assumed per annum. Fuel costs for diesel, natural gas and electricity in the model are based on prices paid by Sierra Nevada in 2006, and 2008 prices for the Kaiser and NetApp facilities. Kaiser and NetApp electricity and diesel prices are based on the tariffs for May, 2008 [PG&E,

2008] and natural gas prices on the January-May historical prices and the futures spot market prices adjusted for location in the period from June-December 2008 [IKUN, 2008].

Efficiency of the chillers, CHP units, and diesel generators is based on actual power production and fuel consumption when possible, and from manufacturer's data sheets in all other cases. The overall macrogrid electrical conversion efficiency was assumed to be 34%. To determine the relative carbon emissions of each proposed scenario, a value for the marginal Northern California electrical grid carbon intensity of 0.14 kg CO_2/kWh is used [Stadler et al., 2008a].

Model Data and Analysis Procedures

In order to meaningfully be able to compare CHP/CCHP systems to backup generators, the increased cost of blackout ride-through capability is incorporated into the capital cost of the CHP/CCHP technology for Scenario 2 and Scenario 3 at each site. The quotes/estimates we received (from Tecogen and Thomson Technology) allow us to put a price on this black-out ridethrough capability at $75-$200/kW for engine generator models. However, in some situations where much of the electronics/switchgear are already in place, the cost of adding the black-out ridethrough capabilities could be much less. For example, one site reported that adding this capability for its existing 1.2 MW microturbine system would cost on the order of $10,000-15,000, or more like $10/kW.

We do not explicitly find the average cost of adding this capability to a fuel cell system such as the one installed at Sierra Nevada. This cost would depend much more greatly on how steady the load was when the fuel cell was supplying back-up power because the ramp rate and min/max capacity range of a fuel cell is limited. In such a case, a battery system, or Uninterruptible Power Supply (UPS) would probably be necessary to smooth transient loads. We assume a $200/kW(capacity) price premium for this blackout ride-through capability across both the fuel cell and engine-generator CHP units. The actual cost of doing this for a fuel cell system could be greater depending on the factors mentioned above.

In addition, other problems can be encountered with CHP as emergency backup. For instance, at the NetApp facility, the UPS, combined with the electromechanical controls on the Hess Microgen unit contributed to a problem where the load was being dumped too quickly on the Microgen units, causing them to shut down [Niblett, Devcon; Renne, NetApp]. A different UPS, or more sophisticated load ramping algorithms on the CHP units could improve blackout ride-through capability in this scenario.

Capacity factor for each facility is based on actual average runtime in 2006 when the systems were intended to be operating continuously. For NetApp, data for a representative year is unavailable so continuous operation is assumed. At the other two facilities, actual runtime was considerably less than the intended operating schedule which dictated 8760 hours/year (24hrs * 365 days/year). Sierra Nevada's fuel cells only operated an average of 6640 hours/year, and Kaiser's CHP units for 6648 hours/year, just over 75% of the time they were scheduled to operate.

Although valuation of reliability differences between diesel generators and other CHP technology was considered in our analysis, the reliability difference of switching from diesel generators to CHP units for emergency power is difficult to quantify and relatively small. Based on average cost per outage and reliability event data for industrial/commercial facilities of this size, the cost of all outages over the course of a year would be:

System Average Interruption Frequency Index (SAIFI) * Cost per Sustained Outage + Momentary Average Interruption Frequency Index (MAIFI) * Cost per Momentary Outage = 1.3*$4.111 + 2.3*1881 = $9,671

Reliability and cost per outage data for California for this example is taken from LaCommare [2004]. Given that there is a small fraction of generators that fail during emergency backup operation, only a small fraction of this $9,671 could be recovered by increased backup system reliability. Since the annual energy costs exceed $1 million for each, this effect on the order of $1,000 in value is "in the noise" and certainly shouldn't affect the relative costs of any of the scenarios compared. Therefore, any difference in diesel and CHP backup generator reliability is ignored in this analysis.

Summary of Modeling Results

The results in Tables 1-3 and Figures 3-5 show there is significant room for savings in both the technologies chosen, and the scheduling of on-site generation at the facilities considered. By comparing the carbon emissions and yearly energy cost of scenario 3 to scenario 1 for each of the three facilities, one can see if currently installed CHP technologies are economically and environmentally favorable at each site. For Sierra Nevada and NetApp the CHP/CCHP system without state incentives is not, from a purely economic standpoint, the best investment. Yet for Kaiser, increasing the total installed capacity of CHP units from 180 kW to a total 600 kW of on-site generation would provide the lowest yearly energy cost. Not surprisingly, due to their inherent efficiency (heat plus electricity generation), scenarios with the greatest number of natural gas CHP technologies had the lowest carbon emissions. For Kaiser Hayward, installing 600 kW of CHP units with blackout ride-through capability would provide an ~10% reduction in carbon emissions, and ~3% cost reduction over the optimal scheduling of their currently installed system.

In the Sierra Nevada and NetApp cases, in the absence of any economic incentives to install CHP the least expensive method to power the facility would be to buy all electricity and natural gas from the utility company. However, this would correspond to a greater than 12% increase in carbon emissions for Sierra Nevada, and ~1% increase in carbon emissions for NetApp compared to optimal scheduling of their currently installed generation technology.

Table 1: Sierra Nevada Brewery Overall Results (2006 Prices)

	Scenario 1	**Scenario 2**	**Scenario 3**
Goal Function Value (= Total Annual Energy Costs) ($)	2,607401	2,586,022	2,044,065
Installed Units for Each Available Technology			
200 kW natural gas fuel cell CHP unit	4	4	0
750 kW diesel generator	3	2	0
Emissions			
Annual Total Carbon Emissions (kg)	2,787,459	2,786,924	3,127,592

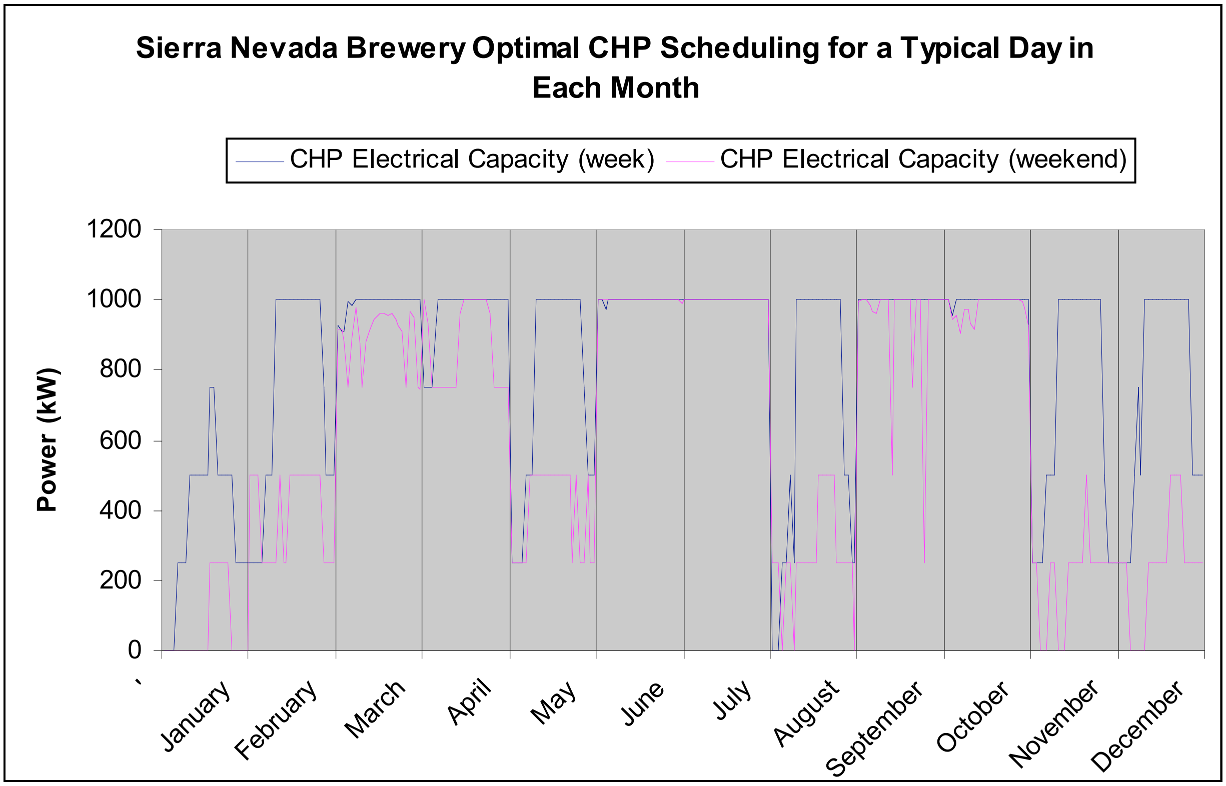

Figure 3: Optimal Scheduling of CHP for the Sierra Nevada Brewery
(Time period for each day's hourly interval data is 0:00H to 23:00H)

Table 2: NetApp Data Center Overall Results (2008 Prices)

	Scenario 1	Scenario 2	Scenario 3
Goal Function Value (= Total Annual Energy Costs) ($)	1,630,858	2,219,106	1,061,670
Installed Units for Each Available Technology			
2 MW diesel generator	2	1	0
375 kW natural gas CCHP unit	3	6	0
Emissions			
Annual Total Carbon Emissions (kg)	1,369,578	1,369,421	1,383,748

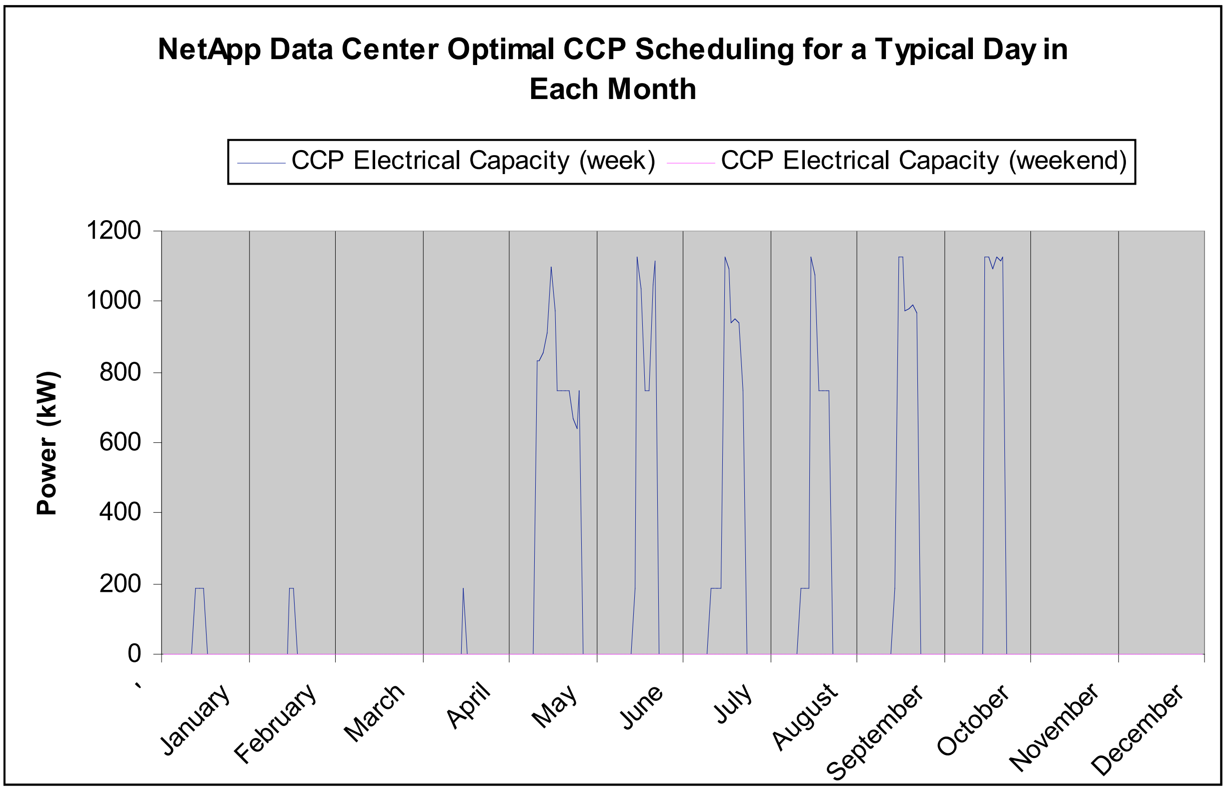

Figure 4: Optimal Scheduling of CHP for the NetApp Data Center
(Time period for each day's hourly interval data is 0:00H to 23:00H)

Table 3: Kaiser Hayward Hospital Overall Results (2008 Prices)

	Scenario 1	Scenario 2	Scenario 3
Goal Function Value (= Total Annual Energy Costs) ($)	1,773,688	1,766,464	1,721,870
Installed Units for Each Available Technology			
350 kW diesel generator	2	2	0
260 kW diesel generator	1	0	0
60 kW natural gas CHP unit	3	4	10
Emissions			
Annual Total Carbon Emissions (kg)	2,199,106	2,169,773	1,980,507

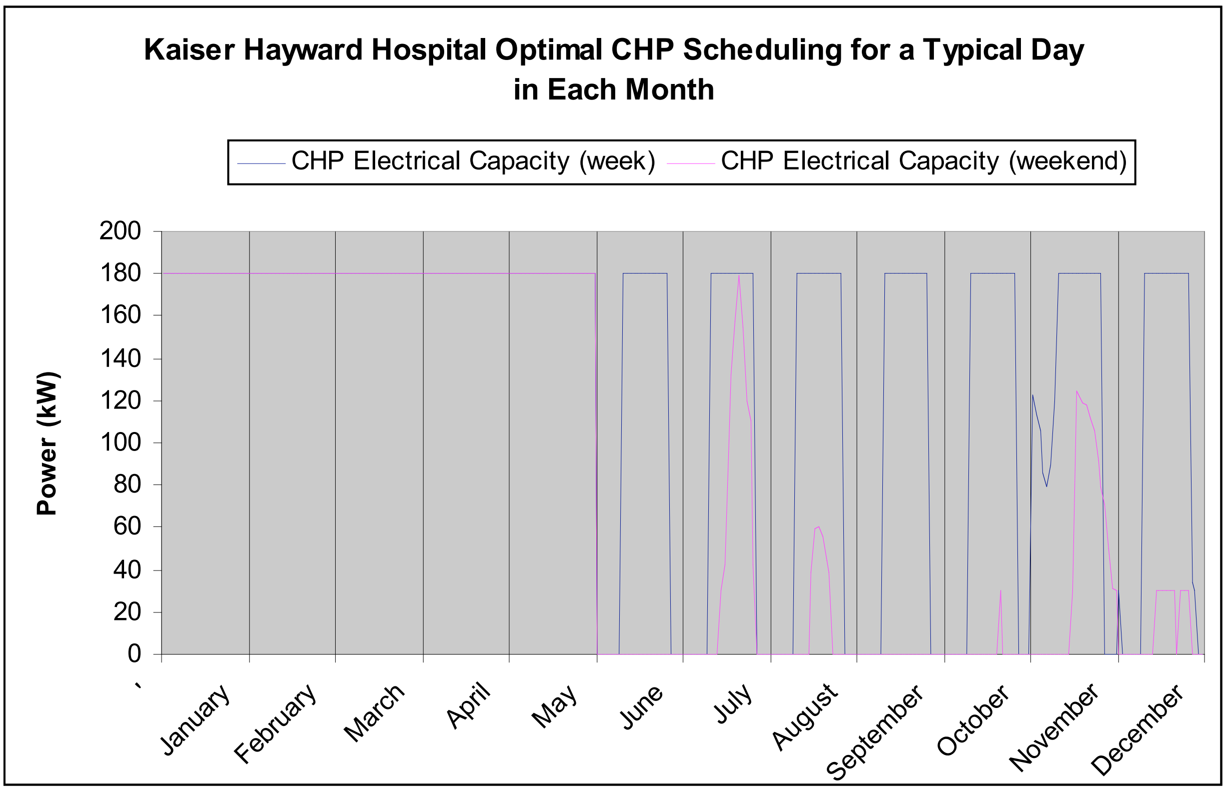

Figure 5: Optimal Scheduling of CHP for the Kaiser Hayward Hospital
(Time period for each day's hourly interval data is 0:00H to 23:00H)

Comparing Scenario 2 to Scenario 1 shows the benefit/cost of substituting for diesel generation with a nearly equivalent capacity of CHP units. In Scenario 2 it is assumed that the CHP/CCHP system was installed initially with the capability for blackout ride-through capability and no cost was incurred for the substituted diesel generators. For Sierra Nevada and NetApp, the carbon emissions savings for this substitution would only be a few hundred kilograms annually; a nearly break-even proposition. For NetApp, however, the cost of installing additional CCHP units to replace the diesel generators would be substantial, adding ~36% to the yearly energy cost compared to the current system. Our analysis shows no clear economic or environmental incentive to provide blackout ride-through capability for Sierra Nevada or NetApp. For Kaiser Hayward, however, substituting for one of the 260 kW diesel generators with 240 kW of natural gas reciprocating engine CHP units with blackout ride-through capability would provide a <0.5% reduction in annual energy cost and a 1.3% reduction in carbon emissions compared to the existing system; a small but significant difference.

In terms of optimal scheduling of the various CHP technologies and facilities considered, it is not surprising that midday and summer operation provided the most economic incentive for the data center, where waste heat was used for cooling. For the hospital, with higher heating loads in the winter, the CHP units were scheduled to run throughout that period on both week days and weekend days. All other things being equal, facilities with steady electrical demand would have a lesser benefit from installing CHP technologies than will those facilities with peaking demand during the middle of the day when electrical prices are at their highest. These peak pricing times are exactly when operating the CHP units will provide the most economic benefit. For instance, because of the steady electrical demand during the weekends compared to the weekdays for the data center, the optimal scheduling for the CCHP system on weekends was to remain always off, as purchase of electricity to drive compressor chillers would be less expensive than generating electricity with the CCHP system while providing supplemental adsorption cooling.

Caveats and Directions for Future Work

It is important to recognize the limitations and strengths of the type of economic optimization performed in this analysis. Because the objective of this optimization is to minimize total yearly energy costs, economic “externalities,” many of them environmental, are ignored. Although the model does evaluate the direct carbon dioxide emissions from all energy generation technology, it does not optimize for this parameter by assigning it a monetary value. Additionally, embedded energy in manufacturing / transportation and life cycle greenhouse gas (GHG) emissions of the various energy generation technologies are ignored. Future work to look more seriously at the relative GHG lifecyle emissions from each of these technologies could motivate an optimization based on some combination of economic and environmental parameters.

Also not included in this analysis are the various state and federal incentives for installing CHP technologies, many of which were used in the installation of the systems at the facilities we analyzed (Self-Generation Incentive Program for instance). Because these incentives vary widely from state to state, can also vary from year to year, and also because they do not represent a uniform market discount, these incentives were not included. We note that at present the SGIP program in California only provides incentives for fuel cell technologies as CHP resources, and is not providing an incentive for combustion technologies.

In addition to the factors above, there were many approximations and concessions made in constructing the load profiles for a couple of the facilities selected. Due to incomplete availability of data for NetApp, the cooling load was assumed to be negligible in the coldest months of the year (December through February) when it is assumed that outside air economizers can provide the vast majority of cooling. The electrical work used to power the fans for this cooling source was also uniformly ignored. In addition, because a composite of load data from the years 2006 and 2007 were used in the Kaiser and Netapp facilities some of the ‘typical’ load profiles input to our economic model may be skewed slightly because in some cases cooling load is coming from a month of data in for instance 2007, while CCHP system output may be from the same month in 2006. Because of the methodology used, the typical week/weekend day loads for each month (as shown in Appendix A) are not strictly an average of every week/weekend day, but instead the actual profile for a day chosen because it most closely matched the average week/weekend daily load for that particular month.

This methodology attempts to capture the complicated transient loads that may be present in a typical day, but hidden on average. This methodology must be considered in viewing the modeled results, especially the optimal scheduling of the CHP system (Figures 3-5), which should therefore be taken as guidelines, not to be strictly followed in actual scheduling of the CHP systems. Frequent repeated startups and shutdowns will obviously be detrimental to the longevity of any CHP/CCHP system and should be avoided.

Finally, this analysis did not, by any means, try to evaluate all potential CCHP technologies, and in fact, some obvious technologies, such as solar were not even considered because they were not installed at any of the selected sites. In fact, no attempt to assess the relative benefit of any CCHP technologies not already installed at the sites evaluated was made (with the obvious exception of black-out ridethrough capability; the addition of which was considered in scenario 2 for all sites). A comprehensive analysis and optimization over all possible technology choices using DER-CAM could guide future CCHP technology selection for premium power applications, although the costs from site to site can vary dramatically depending on the mechanical and electrical upgrades that may be needed for any CCHP installation.

Conclusions

Through comparison of representative scenarios for each of three premium power CHP/CCHP sites (a brewery, a data center, and a hospital) some broad observations can be made about the economic and environmental effects of such installations. It is shown that the economically optimal (i.e. lowest cost w/out state incentives) technology investment for two of the sites is to not invest in the CHP systems at all. For both the brewery and data center, the cost of the CHP system is either too great (e.g. fuel cells), or the system is too inefficient (e.g. adsorption chillers) compared to the price of electricity and natural gas from the utilities to justify installing and operating such a system. For the hospital, however, the currently installed CHP system is an underinvestment, and due to the large and steady heat demands, a greater investment in CHP could significantly benefit the facility in terms of both cost savings and reduction in carbon dioxide emissions.

This analysis also looked at the possibility of replacing existing diesel generation with CCHP systems with blackout ride-through capability. For the brewery, the additional yearly cost and emissions savings from this option would be negligible, assuming a suitable load could be islanded and the capital cost of installing such capability would only be $200/kW beyond that of the existing CHP system. For the hospital, a slight benefit could be achieved by replacing the some diesel generators with natural gas fired reciprocating engine CHP system; this would be on the order of a 1% yearly energy cost and carbon emissions reduction. It might be interesting to look at the proposition of replacing all the diesel generators with these these units in this case. For the data center, however, a negligible environmental benefit was shown and a significant yearly energy cost increase (36%) was predicted by this model.

Overall, no matter what technology was chosen, the underlying theme is that a facility's load profile will determine the relative economic and environmental efficacy that any CHP system would achieve. A system with a high cooling load and no heating load (such as a data center) has comparitively lesser benefit than one with a large heating load (such as a hospital) due to the relatively low-cost of heat recovery systems as compared to adsorption/absorption chiller systems. Expensive and efficient electrical generation technologies (i.e. fuel cells) provide no better performance for facilities with high heat loads (such as a hospital or brewery), than less expensive natural gas fired reciprocating engine technology with heat recovery, but they do provide environmental benefits. Optimal scheduling of any selected technology will be largely determined by the time period of highest thermal demand and highest electrical pricing, with the latter being the dominant factor in determining the most cost effective operation schedule. Of course, running CHP systems at the time of highest electrical pricing will mean running them at the time of the day when ambient air pollution is the worst, and is therefore not recommended in urban and suburban settings.

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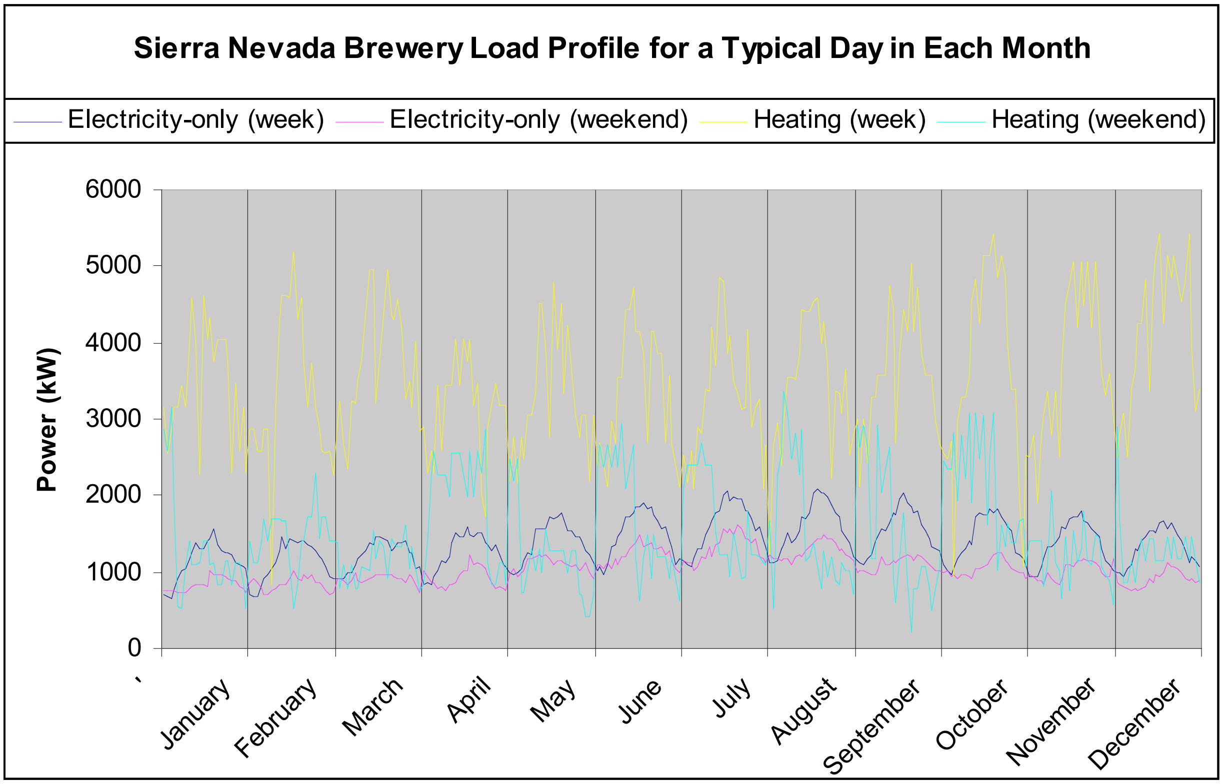
Appendix A – Load Data and DER-CAM Inputs / Results for Each Scenario



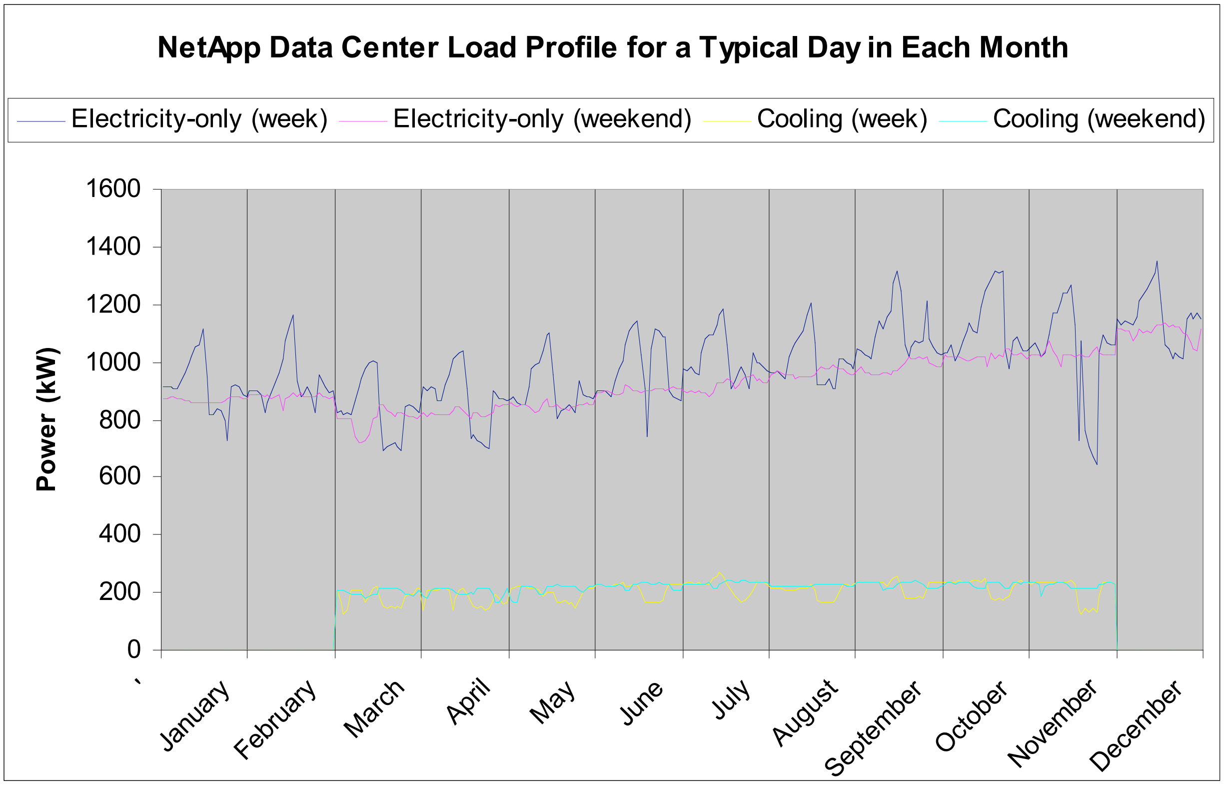
Sierra Nevada DER-CAM Model Summary and Results

+++++++++Summary+++++++++	Scenario 1	Scenario 2	Scenario 3
Goal Function Value (= Total Annual Energy Costs minus Electricity Sales) ($)	2,607,401	2,586,022	2,044,065
Installed Capacity (kW)	3,250	2,500	0
Installed Capacity: Electricity-only (kW)	2,250	1,500	0
Installed Capacity: Electric/Heating (kW)	1,000	1,000	0
Installed Capacity: Electric/Heating/Cooling (kW)	0	0	0
Installed Capacity: Photovoltaics (kW)	0	0	0
Installed Capacity: Natural Gas for I.C.E. (reciprocating engines) (kW)	0	0	0
Installed Capacity: Microturbines (kW)	0	0	0
Installed Capacity: Fuel Cells (kW)	1,000	1,000	0
Electricity Generated Onsite (kWh/a)	6,629,625	6,622,875	0
Fraction of electricity generated onsite (without absorption chiller offset)	0.59	0.59	0
Effective Fraction of electricity generated onsite (includes absorption chiller offset)	0.59	0.59	0
Heating Load Offset by CHP (kWh/a)	2,198,545	2,198,794	0
Cooling Load Offset by CHP (kWh/a)	0	0	0
Utility Electricity Consumption (kWh/a)	4,527,078	4,533,828	1,1156,703
Utility Natural Gas Consumption (kWh/a)	43,635,873	4,3637,219	31,744,791
Total Fuel Consumption (onsite plus fuel for macrogrid electricity) (kWh/a)	5,6950,809	56,972,008	64,558,623

+++++++++Efficiencies and Fractions+++++++++			
Efficiency of Entire Energy Utilization (Onsite and Purchase)	0.64	0.64	0.57
Natural Gas DER System Efficiency (Elec + Heat)	0.63	0.63	UNDF
Natural Gas DER System Efficiency (Federal Regulatory Commission - FERC Definition)	0.55	0.55	UNDF
Fraction of Energy Demand Met On-Site	0.23	0.23	0
Fraction of Electricity-Only End-Use Met by On-Site Generation	0.59	0.59	0
Fraction of Cooling End-Use Met by On-Site Generation	UNDF	UNDF	UNDF
Fraction of Cooling End-Use Met by Absorption Chiller	UNDF	UNDF	UNDF
Fraction of Cooling End-Use Met by Natural Gas	UNDF	UNDF	UNDF
Fraction of Space-Heating End-Use Met by CHP	0.07	0.07	0
Fraction of Space-Heating End-Use Met by Natural Gas	0.93	0.93	1
Fraction of Water-Heating End-Use Met by CHP	UNDF	UNDF	UNDF
Fraction of Water-Heating End-Use Met by Natural Gas	UNDF	UNDF	UNDF
Fraction of Natural Gas-Only End-Use Met by Natural Gas	UNDF	UNDF	UNDF
+++++++++Model 0ptions+++++++++			
Invest	1	1	1
Sales	0	0	0
StandbyOpt	0	0	0
VaryPrice	0	0	0
CHP	0	0	0
CarbonTax	1	1	1
GasForCool	0	0	0
ForcedInvest	1	1	0
+++++++++Model Parameters+++++++++			
IntRate	0.05	0.05	0.05
Standby	0	0	0
Contrct	0	0	0
turnvar	0	0	0
CTax	0	0	0
MktCRate	0.14	0.14	0.14
macroeff	0.34	0.34	0.34
cooleff	0.13	0.13	0.13
MinEffic	0	0	0
Reliability	0.9	0.9	0.9
AvgCapacity	1,000	1,000	1,000
AbsFraction	0	0	0
m2	0	0	0

b2	0	0	0
m3	0	0	0
b3	0	0	0
BaseCaseCost	20,000,000	20,000,000	20,000,000
MaxPaybackPeriod	20	20	20
+++++++++Installed Units for each available Technology++++++++++++			
Available Technologies are technologies with MaxAnnualHour values greater than 0			
in table GenConstraints in folder Technology Data			
FC-------------00200	4	4	0
GT-------------01000	3	2	0
+++++++++Reports on an Annual Basis+++++++++			
Loads (All Numbers in kWh)			
1 kWh = 3412.14 BTU			
Annual Electricity-Only Load Demand	11,156,703	11,156,703	11,156,703
Annual Cooling Load Demand	0	0	0
Annual Space Heating Load	25,395,833	25,395,833	25,395,833
Annual Water Heating Load	0	0	0
Annual Natural Gas-Only Heating Load	0	0	0
Annual Total Energy Demand (kWh)	36,552,536	36,552,536	36,552,536
Generation (All Numbers in kWh)			
1 kWh = 3412.14 BTU			
Total Annual Electricity Generation On Site	6,629,625	6,622,875	0
Annual Electricity Generation On-Site to Meet Electricity-Only Load	6,629,625	6,622,875	0
Annual Electricity Generation On-Site to Meet Cooling Load	0	0	0
Annual On-Site Production of Energy (Electricity + Utilized Waste Heat + Natural Gas) (kWh)	8,388,461	8,381,910	0
Purchase (All Numbers in kWh)			
Annual Electricity Purchase to Meet Electricity-Only Load	4,527,078	4,533,828	1,1156,703
Annual Electricity Purchase to Meet Cooling Load	0	0	0
Natural Gas (All Numbers in kWh)			
Annual Natural Gas-Only Load which is met by Natural Gas	0	0	0
Annual Cooling Load which is met by Natural Gas,	0	0	0
Annual Space Heating Load which is met by Natural Gas	23,636,996	23,636,797	25,395,833

Annual Water Heating Load which is met by Natural Gas (kWh)	0	0	0
CHP (All Numbers in kWh)			
Annual Cooling Load which is met by Absorption Chiller	0	0	0
Annual Load of Water Heating which is met by CHP	0	0	0
Annual Load of Space Heating which is met by CHP	1,758,836	1,759,036	0
Energy Carriers			
Annual DER Natural Gas Purchases (kWh)	14,089,627	14,091,223	0
Annual NON DER Natural Gas Purchases (kWh)	29,546,246	29,545,997	31,744,791
Annual Net Gas Purchase (kWh)	43,635,873	43,637,219	31,744,791
Annual Total Gas Costs ($)	1156,728	1,157,517	852,172
Annual Net Diesel Purchase (kWh)	22,727	0	0
Annual Diesel Bill ($)	1,028	0	0
Emissions			
Annual On-site Carbon Emissions from Natural Gas DER (kg)	694,900	694,979	0
Annual On-site Carbon Emissions from Diesel DER (kg)	1,546	0	0
Annual On-site Carbon Emissions from Natural Gas (kg)	1,457,221	1,457,209	1,565,653
Annual Off-site Carbon Emissions (Macrogrid) (kg)	633,791	634,736	1,561,938
Annual Total Carbon Emissions (kg)	2,787,459	2,786,924	3,127,592



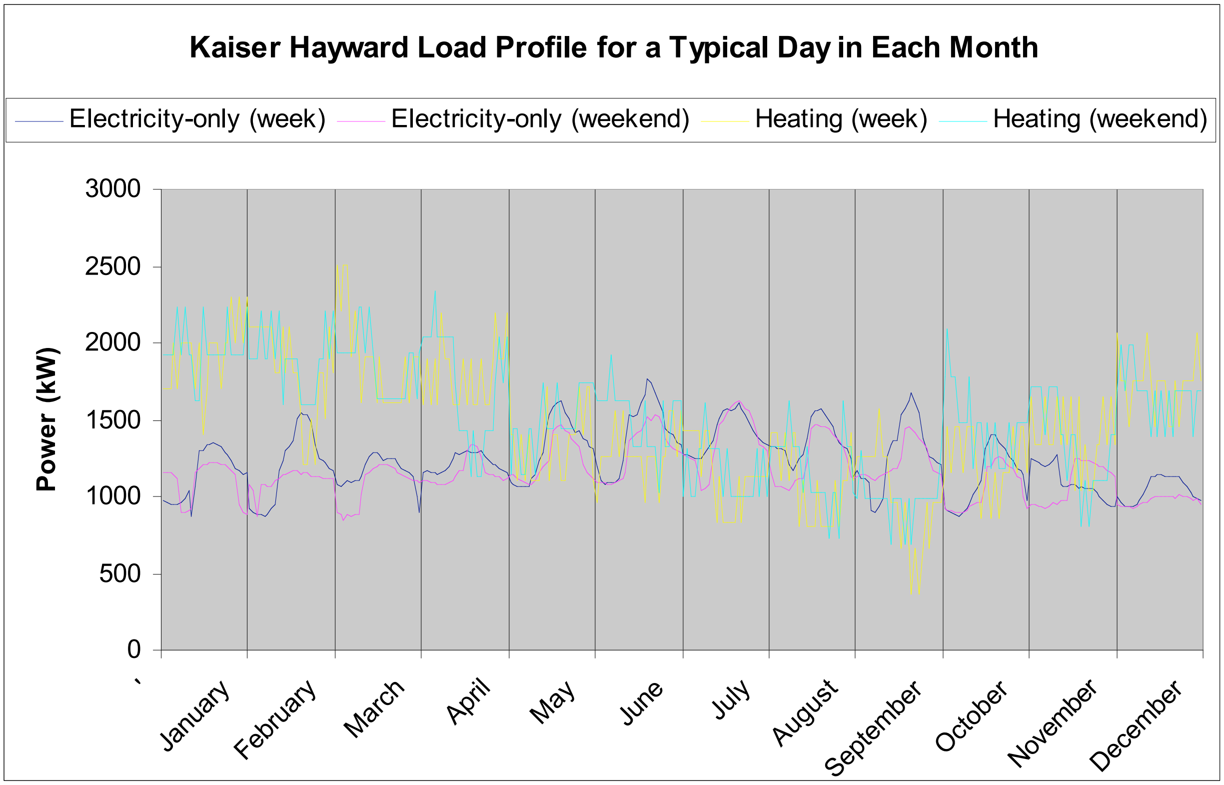
NetApp DER-CAM Model Summary and Results

+++++++++Summary+++++++++	Scenario 1	Scenario 2	Scenario 3
Goal Function Value (= Total Annual Energy Costs minus Electricity Sales) ($)	1,630,858	2,219,106	1,061,670
Installed Capacity (kW)	5,125	4,250	0
Installed Capacity: Electricity-only (kW)	4,000	2,000	0
Installed Capacity: Electric/Heating (kW)	0	0	0
Installed Capacity: Electric/Heating/Cooling (kW)	0	0	0
Installed Capacity: Photovoltaics (kW)	0	0	0
Installed Capacity: Natural Gas for I.C.E. (reciprocating engines) (kW)	1,125	2,250	0
Installed Capacity: Microturbines (kW)	0	0	0
Installed Capacity: Fuel Cells (kW)	0	0	0
Electricity Generated Onsite (kWh/a)	925,914	937,043	0
Fraction of electricity generated onsite (without absorption chiller offset)	0.1	0.1	0
Effective Fraction of electricity generated onsite (includes absorption chiller offset)	0.11	0.11	0
Heating Load Offset by CHP (kWh/a)	0	0	0
Cooling Load Offset by CHP (kWh/a)	163,743	165,619	0
Utility Electricity Consumption (kWh/a)	8,794,258	8,781,253	9,883,915
Utility Natural Gas Consumption (kWh/a)	2,805,801	2,839,524	0
Total Fuel Consumption (onsite plus fuel for macrogrid electricity) (kWh/a)	28671266	28,666,740	29,070,339

+++++++++Efficiencies and Fractions+++++++++			
Efficiency of Entire Energy Utilization (Onsite and Purchase)	0.34	0.34	0.34
Natural Gas DER System Efficiency (Elec + Heat)	0.78	0.78	UNDF
Natural Gas DER System Efficiency (Federal Regulatory Commission - FERC Definition)	0.55	0.55	UNDF
Fraction of Energy Demand Met On-Site	0.11	0.11	0
Fraction of Electricity-Only End-Use Met by On-Site Generation	0.1	0.11	0
Fraction of Cooling End-Use Met by On-Site Generation	0.03	0.02	0
Fraction of Cooling End-Use Met by Absorption Chiller	0.12	0.12	0
Fraction of Cooling End-Use Met by Natural Gas	0	0	0
Fraction of Space-Heating End-Use Met by CHP	UNDF	UNDF	UNDF
Fraction of Space-Heating End-Use Met by Natural Gas	UNDF	UNDF	UNDF
Fraction of Water-Heating End-Use Met by CHP	UNDF	UNDF	UNDF
Fraction of Water-Heating End-Use Met by Natural Gas	UNDF	UNDF	UNDF
Fraction of Natural Gas-Only End-Use Met by Natural Gas	UNDF	UNDF	UNDF
+++++++++Model 0ptions+++++++++			
Invest	1	1	1
Sales	0	0	0
StandbyOpt	0	0	0
VaryPrice	0	0	0
CHP	0	0	0
CarbonTax	1	1	1
GasForCool	0	0	0
ForcedInvest	1	1	0
+++++++++Model Parameters+++++++++			
IntRate	0.05	0.05	0.05
Standby	0	0	0
Contrct	0	0	0
turnvar	0	0	0
CTax	0	0	0
MktCRate	0.14	0.14	0.14
macroeff	0.34	0.34	0.34
cooleff	0.13	0.13	0.13
MinEffic	0	0	0
Reliability	0.9	0.9	0.9
AvgCapacity	1,000	1,000	1,000
AbsFraction	0	0	0
m2	0	0	0
b2	0	0	0

m3	0	0	0
b3	0	0	0
BaseCaseCost	20,000,000	20,000,000	20,000,000
MaxPaybackPeriod	20	20	20
+++++++++Installed Units for each available Technology++++++++++++			
Available Technologies are technologies with MaxAnnualHour values greater than 0			
in table GenConstraints in folder Technology Data			
GT-------------01000	2	1	0
NG-------------00200	3	6	0
+++++++++Reports on an Annual Basis+++++++++			
Loads (All Numbers in kWh)			
1 kWh = 3412.14 BTU			
Annual Electricity-Only Load Demand	8,501,995	8,501,995	8,501,995
Annual Cooling Load Demand	1,381,920	1,381,920	1,381,920
Annual Space Heating Load	0	0	0
Annual Water Heating Load	0	0	0
Annual Natural Gas-Only Heating Load	0	0	0
Annual Total Energy Demand (kWh)	9,883,915	9,883,915	9,883,915
Generation (All Numbers in kWh)			
1 kWh = 3412.14 BTU			
Total Annual Electricity Generation On Site	925,914	937,043	0
Annual Electricity Generation On-Site to Meet Electricity-Only Load	891,046	902,584	0
Annual Electricity Generation On-Site to Meet Cooling Load	34,868	34,459	0
Annual On-Site Production of Energy (Electricity + Utilized Waste Heat + Natural Gas) (kWh)	1089657.22	1102662	0
Purchase (All Numbers in kWh)			
Annual Electricity Purchase to Meet Electricity-Only Load	7,610,949	7,599,411	8,501,995
Annual Electricity Purchase to Meet Cooling Load	1,183,309	1,181,842	1,381,920
Natural Gas (All Numbers in kWh)			
Annual Natural Gas-Only Load which is met by Natural Gas	0	0	0
Annual Cooling Load which is met by Natural Gas,	0	0	0
Annual Space Heating Load which is met by Natural Gas	0	0	0
Annual Water Heating Load which is met by Natural Gas (kWh)	0	0	0

CHP (All Numbers in kWh)			
Annual Cooling Load which is met by Absorption Chiller	163,743	165,619	0
Annual Load of Water Heating which is met by CHP	0	0	0
Annual Load of Space Heating which is met by CHP	0	0	0
Energy Carriers			
Annual DER Natural Gas Purchases (kWh)	2,805,801	2,839,524	0
Annual NON DER Natural Gas Purchases (kWh)	0	0	0
Annual Net Gas Purchase (kWh)	2,805,801	2,839,524	0
Annual Total Gas Costs ($)	113,557	114,910	4,117.5
Annual Net Diesel Purchase (kWh)	0	0	0
Annual Diesel Bill ($)	0	0	0
Emissions			
Annual On-site Carbon Emissions from Natural Gas DER (kg)	138,382	140,045	0
Annual On-site Carbon Emissions from Diesel DER (kg)	0	0	0
Annual On-site Carbon Emissions from Natural Gas (kg)	0	0	0
Annual Off-site Carbon Emissions (Macrogrid) (kg)	1,231,196	1,229,375	1,383,748
Annual Total Carbon Emissions (kg)	1,369,578	1,369,421	1,383,748



Kaiser Hayward DER-CAM Model Summary and Results

+++++++++Summary+++++++++	Scenario 1	Scenario 2	Scenario 3
Goal Function Value (= Total Annual Energy Costs minus Electricity Sales) ($)	1,773,688	1,766,464	1,721,870
Installed Capacity (kW)	1140	940	600
Installed Capacity: Electricity-only (kW)	960	700	0
Installed Capacity: Electric/Heating (kW)	180	240	600
Installed Capacity: Electric/Heating/Cooling (kW)	0	0	0
Installed Capacity: Photovoltaics (kW)	0	0	0
Installed Capacity: Natural Gas for I.C.E. (reciprocating engines) (kW)	180	240	600
Installed Capacity: Microturbines (kW)	0	0	0
Installed Capacity: Fuel Cells (kW)	0	0	0
Electricity Generated Onsite (kWh/a)	1,042,695	1,422,194	3,897,462
Fraction of electricity generated onsite (without absorption chiller offset)	0.1	0.13	0.37
Effective Fraction of electricity generated onsite (includes absorption chiller offset)	0.1	0.13	0.37
Heating Load Offset by CHP (kWh/a)	1,995,719	2,721,818	7,416,044
Cooling Load Offset by CHP (kWh/a)	0	0	0
Utility Electricity Consumption (kWh/a)	9,530,707	9,151,208	6,675,940
Utility Natural Gas Consumption (kWh/a)	17,534,611	18,017,106	21,205,898
Total Fuel Consumption (onsite plus fuel for macrogrid electricity) (kWh/a)	45,566,102	44,932,424	40,841,017

+++++++++Efficiencies and Fractions+++++++++			
Efficiency of Entire Energy Utilization (Onsite and Purchase)	0.52	0.52	0.58
Natural Gas DER System Efficiency (Elec + Heat)	0.92	0.91	0.91
Natural Gas DER System Efficiency (Federal Regulatory Commission - FERC Definition)	0.61	0.61	0.61
Fraction of Energy Demand Met On-Site	0.11	0.15	0.42
Fraction of Electricity-Only End-Use Met by On-Site Generation	0.1	0.13	0.37
Fraction of Cooling End-Use Met by On-Site Generation	UNDF	UNDF	UNDF
Fraction of Cooling End-Use Met by Absorption Chiller	UNDF	UNDF	UNDF
Fraction of Cooling End-Use Met by Natural Gas	UNDF	UNDF	UNDF
Fraction of Space-Heating End-Use Met by CHP	0.12	0.17	0.46
Fraction of Space-Heating End-Use Met by Natural Gas	0.88	0.83	0.54
Fraction of Water-Heating End-Use Met by CHP	UNDF	UNDF	UNDF
Fraction of Water-Heating End-Use Met by Natural Gas	UNDF	UNDF	UNDF
Fraction of Natural Gas-Only End-Use Met by Natural Gas	UNDF	UNDF	UNDF
+++++++++Model 0ptions+++++++++			
Invest	1	1	1
Sales	0	0	0
StandbyOpt	0	0	0
VaryPrice	0	0	0
CHP	0	0	0
CarbonTax	1	1	1
GasForCool	0	0	0
ForcedInvest	1	1	0
+++++++++Model Parameters+++++++++			
IntRate	0.05	0.05	0.05
Standby	0	0	0
Contrct	0	0	0
turnvar	0	0	0
CTax	0	0	0
MktCRate	0.14	0.14	0.14
macroeff	0.34	0.34	0.34
cooleff	0.13	0.13	0.13
MinEffic	0	0	0
Reliability	0.9	0.9	0.9
AvgCapacity	1,000	1,000	1,000
AbsFraction	0	0	0
m2	0	0	0
b2	0	0	0

m3	0	0	0
b3	0	0	0
BaseCaseCost	20,000,000	20,000,000	20,000,000
MaxPaybackPeriod	20	20	20
+++++++++Installed Units for each available Technology++++++++++++			
Available Technologies are technologies with MaxAnnualHour values greater than 0			
in table GenConstraints in folder Technology Data			
GT-------------05000	2	2	0
GT-------------10000	1	0	0
NG------------00060	3	4	10
+++++++++Reports on an Annual Basis+++++++++			
Loads (All Numbers in kWh)			
1 kWh = 3412.14 BTU			
Annual Electricity-Only Load Demand	10,573,402	10,573,402	10,573,402
Annual Cooling Load Demand	0	0	0
Annual Space Heating Load	12,967,715	12,967,715	12,967,715
Annual Water Heating Load	0	0	0
Annual Natural Gas-Only Heating Load	0	0	0
Annual Total Energy Demand (kWh)	23,541,117	23,541,117	23,541,117
Generation (All Numbers in kWh)			
1 kWh = 3412.14 BTU			
Total Annual Electricity Generation On Site	1,042,695	1422194	3897462
Annual Electricity Generation On-Site to Meet Electricity-Only Load	1,042695	1,422,194	3,897,462
Annual Electricity Generation On-Site to Meet Cooling Load	0	0	0
Annual On-Site Production of Energy (Electricity + Utilized Waste Heat + Natural Gas) (kWh)	2,639,270	3,599,649	9,830,297
Purchase (All Numbers in kWh)			
Annual Electricity Purchase to Meet Electricity-Only Load	9,530,707	9,151,208	6,675,940
Annual Electricity Purchase to Meet Cooling Load	0	0	0
Natural Gas (All Numbers in kWh)			
Annual Natural Gas-Only Load which is met by Natural Gas	0	0	0
Annual Cooling Load which is met by Natural Gas,	0	0	0
Annual Space Heating Load which is met by Natural Gas	11,371,140	10,790,261	7,034,880

Annual Water Heating Load which is met by Natural Gas (kWh)	0	0	0
CHP (All Numbers in kWh)			
Annual Cooling Load which is met by Absorption Chiller	0	0	0
Annual Load of Water Heating which is met by CHP	0	0	0
Annual Load of Space Heating which is met by CHP	1,596,575	2,177,455	5,932,835
Energy Carriers			
Annual DER Natural Gas Purchases (kWh)	3,320,685	4,529,281	12,412,298
Annual NON DER Natural Gas Purchases (kWh)	14,213,926	13,487,826	8,793,600
Annual Net Gas Purchase (kWh)	17,534,611	18,017,106	21,205,898
Annual Total Gas Costs ($)	672,920	691,136	813,706
Annual Net Diesel Purchase (kWh)	0	0	0
Annual Diesel Bill ($)	0	0	0
Emissions			
Annual On-site Carbon Emissions from Natural Gas DER (kg)	163,776	223,384	612,175
Annual On-site Carbon Emissions from Diesel DER (kg)	0	0	0
Annual On-site Carbon Emissions from Natural Gas (kg)	701,031	665,220	433,700
Annual Off-site Carbon Emissions (Macrogrid) (kg)	1,334,299	1,281,169	934,632
Annual Total Carbon Emissions (kg)	2,199,106	2,169,773	1,980,507