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CHP Demonstration Projects at Federal Facilities

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ABSTRACT

Severe winter and summer weather, combined with energy prices seemingly spiraling out of control, have caused people in both the private and public sectors to consider combined heat and power (CHP). These systems, combining on-site generation of electricity with heat recovery for space heating, potable hot water, or indirect-fired absorption chillers for air conditioning, can result in significant cost and energy savings. Organizations in different branches of the U.S. government are at various stages in the design and installation of CHP projects. The Federal Energy Management Program (FEMP) is working with three of these organizations and their private sector partners to document CHP energy savings through pre- and post-retrofit monitoring of system operation and energy use and through computer modeling with typical year hourly weather data. Documentation of these success stories is expected to provide compelling arguments for other federal agencies to install CHP systems.

Sufficient pre-retrofit data have been collected at one site (the 82nd Heating and Cooling Steam Plant at Fort Bragg, North Carolina) to perform an analysis and project possible fuel use and electrical production. One configuration of equipment is considered—three 3.5 MW gas turbines with heat recovery steam generators and a supplemental boiler for peak loading—and compared with the existing gas-fired steam boiler plant. Turbine operation is controlled to meet the distribution system thermal loads, while electricity produced offsets purchases that would be made from the local utility. It is projected that one gas turbine would operate continuously, a second would operate at full load 92% of the time and at part load 8% of the time, and that the third would operate at full-load 54% of the time and at part load 38% of the time and would be idle 8% of the time. Gas turbine operation would provide 495.2 (469,700 $\times 10^6$ Btu) of the 583.5 TJ (553,400 $\times 10^6$ Btu) annual thermal load while producing 86,490 MWh of electricity; natural gas use increases from 748 TJ (7.10 $\times 10^6$ therms) using the steam boilers to 1210 TJ (11.5 $\times 10^6$ therms) for the turbines and supplemental boiler.

Estimated reductions in energy costs are heavily dependent on the relative costs of electricity and natural gas. On-site generation avoids purchases of approximately $2.5 million of electricity based on the average real time prices for 1998 through 2000. The net difference in costs for natural gas between the existing boiler plant and the proposed gas turbine plant is about $1.61 million. Savings in energy costs would be approximately $890,000 per year using average 1999 natural gas rates for industrial customers in North Carolina (EIA 2001).

INTRODUCTION

Though some areas of the United States have been affected more than others, everyone has been affected by the extreme hot and cold temperatures in the past year and the large increases in price for heating oil, natural gas, and electricity. Even without considering fuel supplies and blackouts, people in both the public and private sectors are thinking more than ever about keeping their offices, businesses, and homes sufficiently comfortable in summer and winter. State and federal facilities are examining or re-examining their operations to stretch the taxpayers' dollars as far as possible. One option at which they are looking, as are many businesses, is combined heat and power, the on-site generation of electricity with recovery of waste heat to produce steam or hot water for space conditioning, potable hot water, or even chilled water

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Figure 1 *82nd heating and cooling plant.*

Figure 2 *Barracks served by 82nd heating and cooling plant.*

for cooling. The Federal Energy Management Program (FEMP) is working with partnerships to document energy and money savings through CHP projects at several federal facilities. These include planned installations of gas turbine generators at the Fort Bragg Army Base in North Carolina and the Twenty-Nine Palms Marine Base in California and microturbine generators at Gateway National Recreation Area in Brooklyn, New York.

FEMP's role in these partnerships is limited to data collection before and after installation of CHP equipment in order to establish baseline heating, cooling, and electrical loads and pre- and post-retrofit energy use. Analysis and documentation of this information will be valuable for other federal facilities in their own evaluations and considerations of CHP and energy management. FEMP's partners in these activities include private engineering consulting firms, branches of the U.S. military, the National Park Service, the Army Corps of Engineers, equipment manufacturers, state governments, an ESCO, and a national laboratory. The analysis and results presented later in this paper are those of the authors in support of FEMP's objectives; the other partners are performing their own analyses for design and budgeting.

PROJECT SITES

Each of the three projects is proceeding on an independent schedule. Work at Fort Bragg has proceeded to system design and specification, selection of equipment, and arrangements for financing and contracted facility operations. Gas turbine generators with heat recovery steam generators (HRSG) will be installed to provide approximately 10 MW of capacity; the electrical load for Fort Bragg varies from 33 MW to 99 MW so all electricity produced can be used on the base to offset purchases from the local utility. Gas turbines purchased from an established supplier will be installed at the 82nd Central Heating and Cooling Plant, replacing several gas boilers. The 82nd plant provides steam and hot water to about 100 buildings totaling 228,000 m^2 (3.1 million ft^2) of floor area; 19 new buildings requiring steam and hot and chilled water are being constructed that will add 38,400 m^2 (413,000 ft^2) to the service area. The current facility consists of four 32.5 GJ (36,000 lb/h) and one 54.2 GJ (60,000 lb/h) natural gas or fuel oil fired boilers producing saturated steam at up to 1140 kPa (150 psig); the Army contracts for natural gas at interruptible rates and fuel oil is used when necessary to avoid service interruptions. A recent gas combustion test on the boilers indicated operating efficiencies in the upper 70s to low 80s. The older barracks are supplied with steam from a common header but the new barracks under construction will be serviced using hot water (116°C/240°F) lines; a 2880 kW (820 ton) centrifugal chiller produces chilled water for air conditioning the new barracks complex. Equipment is scheduled for installation in the spring of 2001.

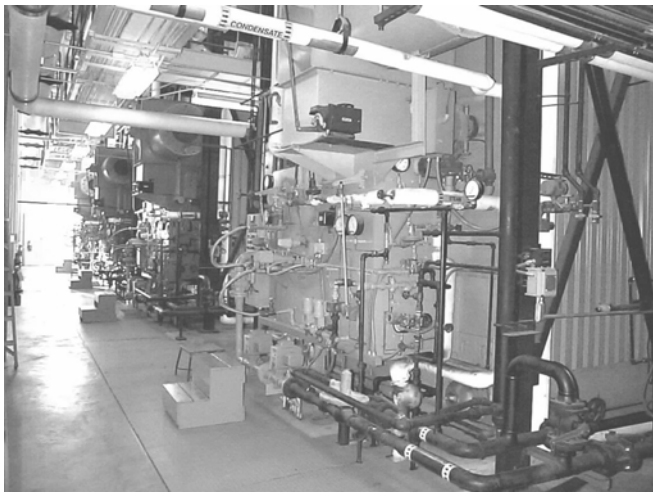

Figure 3 *Steam boilers.*

Gateway National Recreation Area is a National Park Service facility in the heart of the New York City metropolitan

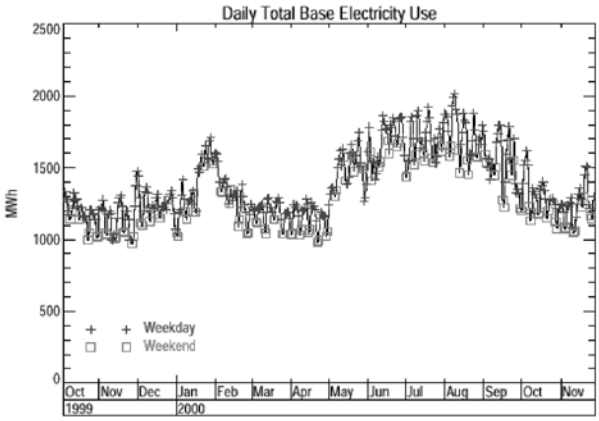

Figure 4 *Fort Bragg electrical loads.*

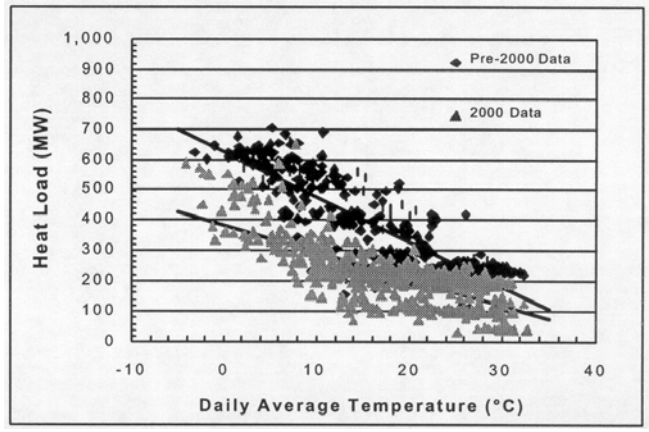

Figure 5 *Thermal loads for the 82nd heating and cooling steam plant at Fort Bragg.*

area. It includes land that was the site of the first airport serving New York, Floyd Bennett Field. Disputes between the city and Newark, New Jersey, over the location of air mail facilities and shifting of commercial air traffic to LaGuardia Field in 1936 led to the decline of Floyd Bennett Field. The airport saw service during World War II and the Korean War for air operations and also as a Coast Guard base, but the island has subsequently reverted to a wildlife preserve.

The age of the buildings at Floyd Bennett Field were a factor in the selection of this site for a CHP demonstration project. The Park Service Headquarters are located in an old airport administration building (Building 69) that uses a four-pipe, hydronic heating system that is ideal for retrofitting with a CHP system, providing both hot and chilled water for heating and air conditioning. Building 69 is currently heated using an oil-fired boiler and hot water distribution system; cooling is provided by a 140 kW (40 ton) air-cooled chiller. Work on the retrofit has not proceeded as far as the efforts have at Fort Bragg, but the proposal is to install 180 kW of on-site power generation using microturbine generators with heat recovery for space heating, potable hot water, and to drive an absorption chiller for chilled water. Design specifications are being completed in the spring of 2001 with construction scheduled for early summer.

The Marine installation at Twenty-Nine Palms, California, currently has a peak electric demand of 16.4 MW, an average demand of 8.9 MW, and consumes 78×10^6 kWh of electricity annually. It uses three 8800 kW boilers to produce high-pressure hot water for three supply loops at 160°C (320°F) at 1130 kPa (150 psig); natural gas consumption is 85 MWh per year. Efforts are underway for design and installation of a CHP plant using a 7.1 MW gas turbine with a 9.4 MW heat recovery steam generator. Documentation of the pre- and post-retrofit systems at Twenty-Nine Palms may be the subject of a future publication.

GAS TURBINE CHP

Electricity is monitored at 15-minute intervals at each of the three substations serving Fort Bragg. Historical records show usage ranging from 1000 MWh to nearly 2000 MWh per day from October 1999 to November 2000 (see Figure 4) with minimum and maximum demand rates of 33 and 99 MW. The electric loads are not metered independently for the buildings served by the 82nd Steam Plant, but that is not particularly relevant to this project. It is important that the overall base electricity demand exceeds the capacity of the proposed on site generator.

The operations staff at the 82nd Steam Plant have maintained daily output logs for each of the boilers. Analysis of these data indicate two distinct groups of heating loads served by the 82nd Steam Plant, those occurring before a temporary closure of barracks in 2000 and those after. The historical, pre-2000 data are of primary interest in this analysis because loads are expected to return to those levels as new barracks are constructed. For the purposes of this analysis, it is assumed that plant heating loads can be approximated using a linear fit to the pre-2000 data. This trend is shown in Figure 5 where the heat load decreases as the outdoor temperature increases up to about 32°C (90°F) (diamonds for pre-2000, triangles for 2000 data).

The CHP plant needs to be carefully sized in order to optimize cost and efficiency. Very frequently systems are described in terms of their electrical efficiency and their resource efficiency, the sum of electrical efficiency and percentage of waste heat recovery. Just because waste heat is recovered, though, does not mean that it can necessarily be used. Figure 6 is a coarse representation of the energy inputs and outputs for a CHP plant. Some of the energy content of the fuel is converted to provide electrical and useful thermal outputs while the remaining energy is lost through radiation, vibration, etc.; some cannot be recovered due to heat exchanger sizing and minimum temperature constraints; and some energy may be recoverable but is not needed to meet thermal loads. A good system design matches the amount of recoverable heat to the system thermal loads in order to minimize heat recovered in excess of the loads that must then be rejected to the environment.

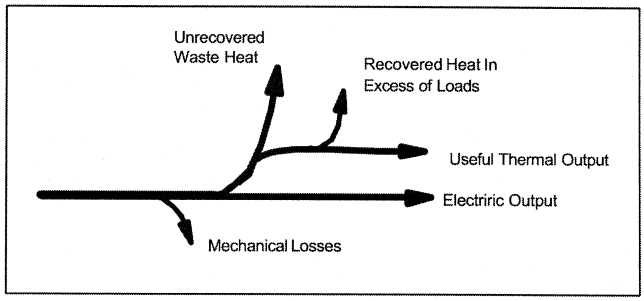

Figure 6 *Energy diagram for CHP plant.*

One option that was considered for the plant retrofit was the use of three 3.5 MW gas turbine generators operating in tandem, one, two, or all three at a time, to track thermal loads while minimizing excess recovered heat at part-load operation. The correlation of thermal loads was used with hourly temperature data to estimate heat output in a typical year for the 82nd Steam Plant. A load duration curve was constructed from the hourly load calculations to evaluate the relationship of heating load and annual hours of occurrence (ASHRAE 1992). The load duration curve is shown in Figure 7 with an indication of the staging of the three turbines. The graph shows that the 82nd Steam Plant has a thermal load above 5.8 MW (20×10^6 Btu/h) 100% of the time, above 11.7 MW (40×10^6 Btu/h) about 90% of the time, and above 17.7 MW (60×10^6 Btu/h) about 50% of the time. A single 10.5 MW turbine generator would provide about 16.7 MW (57×10^6 Btu/h) at the rating condition, meaning that if it were operated to follow the thermal load for the 82nd Steam Plant it would only operate under full load about 53% of the time. All of the rest of the time it would operate at reduced load, at lower efficiency, or cycling with resultant wear and tear on the equipment and increased maintenance costs and down time.

Figure 7 also contains dotted lines showing the thermal capacity of three 3.5 MW turbine generators operating in tandem to track the thermal load. The first turbine operates 100% of the time, producing electricity for use on base and steam or hot water for barracks and administrative buildings. The second turbine operates under full load about 92% of the time and at part load the rest of the time. The third turbine is used only when the load is above 11.1 MW (38×10^6 Btu/h); it is run under part load up to 16.7 MW (57×10^6 Btu/h) and at full load above that point. A supplemental boiler is needed to meet the peak thermal load during the 53% of the wintertime hours that the load is above 22.8 MW (78×10^6 Btu/h).

The performance of a gas turbine varies both with inlet air temperature and altitude as well as with load conditions. The turbine-generator set consists of an air compressor mounted on the same shaft as the turbine, a combustion chamber, and an electric generator that may or may not be mounted on the

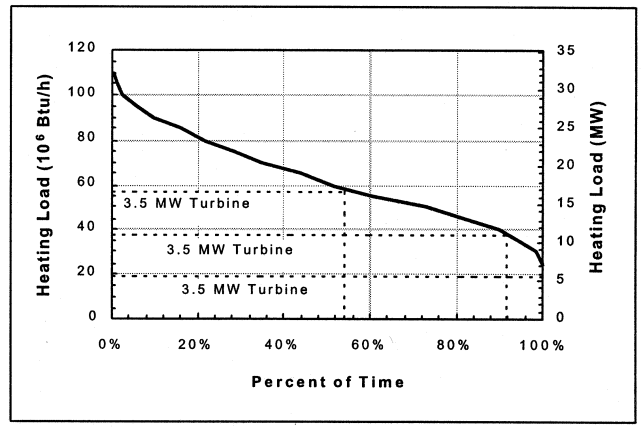

Figure 7 *Thermal load distribution curve for the 82nd steam plant.*

TABLE 1
Gas Turbine Rate Performance

Rating Point Performance	Condition	
Temperature	15ºC	59ºF
Relative Humidity	60%	60%
Electrical Capacity	3.518 MW	3.518 MW
Fuel Rate	12.4 MW	42.3×10^6 Btu/h
Thermal Capacity	5.7 MW	19.4×10^6 Btu/h

shaft with the turbine (Orlando 1996, p. 25). The air compressor is a constant volume device, always drawing in the same volume of air. As air density increases with declining outdoor temperatures, the mass of air drawn into the combustion chamber increases. As air density decreases at higher temperatures, a lower mass of air enters the machine. Turbine capacity decreases as the mass flow rate of air decreases. The air compressor also represents a fairly high and fairly constant parasitic power load on the turbine (Orlando 1996, p. 25). Compressor power can represent as much as 30% of the combustion energy. Consequently, turbine efficiency drops off rapidly under part-load operation.

Table 1 contains electrical capacity and fuel rate for a commercially available, 3.5 MW gas turbine generator with an HRSG (VPS 2000); estimated thermal capacity is also shown. The rated electrical efficiency is 28.7%. Performance curves were derived to estimate operation at other temperatures and part-load conditions using the rating point information, psychrometric data, and curves for part-load operation of a 16 MW turbine (Orlando 1996, p. 27). Figure 8 shows the peak and base capacity for a 3.5 MW turbine across a range of ambient (inlet) air temperatures as well as curves indicating electrical capacity at part-load fuel rates. Figure 9 is similar to Figure 8, except it shows estimated thermal capacity across

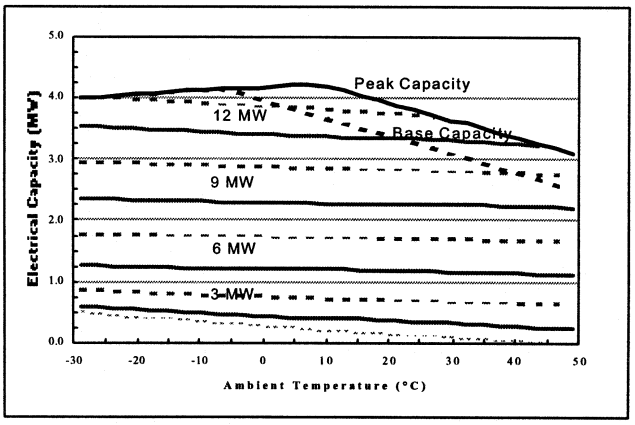

Figure 8 *Capacity and fuel rate for a 3.5 MW gas turbine generator.*

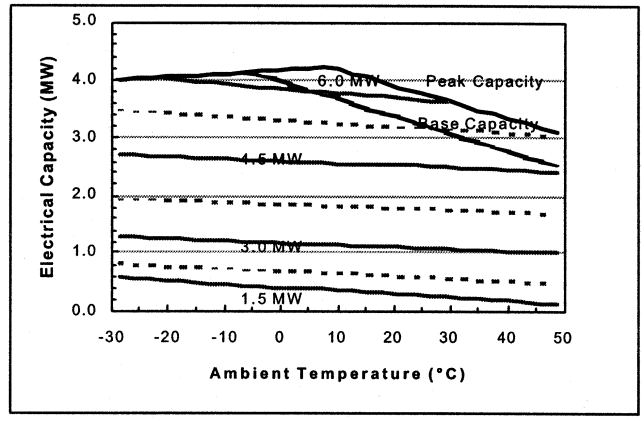

Figure 9 *Electrical and thermal capacities for a 3.5 MW gas turbine generator.*

the range of operating conditions, assuming a heat exchanger effectiveness of 0.68 for the HRSG.

CALCULATIONS AND RESULTS

The turbine-generator performance curves were used with typical weather data for central North Carolina to estimate annual gas consumption and electricity production. Turbine operation was simulated to follow the thermal loads for the 82nd Steam Plant. The assumed linear relationship between temperature and heat load was used with dry-bulb temperature data to calculate overall thermal loads, heat output and fuel input to each of the three turbine-generators as illustrated in Figure 7, electricity produced, and supplemental boiler heat output and fuel input.

The portions of the heating load supplied by each of the turbines are shown in Figure 10; the start-up times of each of the turbines and the supplemental boiler have been staggered in this drawing only to illustrate the point and are not representative of how the systems operate. In this picture, the dark solid line at the left shows fluctuations of the heating load with the ambient temperature. The first turbine is started, providing heat at a relatively constant level with variations in output due to operating temperatures. The second turbine is started around April 6, providing a combined heat output that satisfies the lowest thermal loads. The third turbine is started several days later and runs at part load much of the time. The supplemental boiler is shown starting about April 10 to meet the peak thermal loads. Normal operation, of course, would be for all systems to be on line and functional except at the lowest loads.

Results of the calculations are listed in Table 2. The calculations for the combination of three 3.5 MW gas turbines show that they provide nearly 98% of the total heat load on the 82nd Heating and Cooling Steam Plant while producing 86,490 MWh of electricity. The annual average electrical efficiency is 28.4%, after accounting for temperature variations and part-load operation; the annual resource efficiency is 73.6%. The

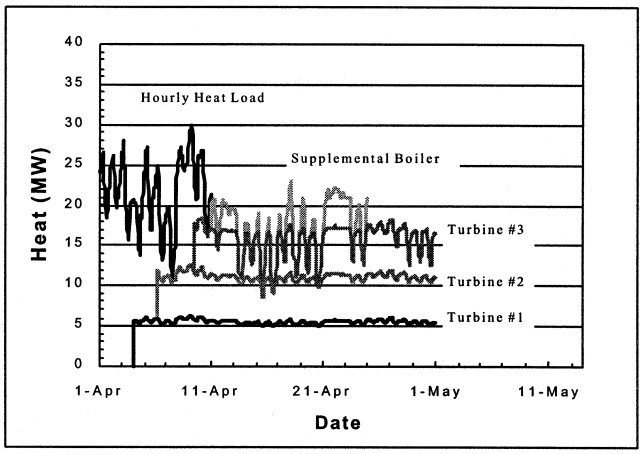

Figure 10 *Thermal loads with staged output from gas turbines and supplemental boiler.*

comparison to the baseline system using steam boilers shows an increase in gas consumption of 1208 TJ (4.37×10^6 therms) while producing 86,490 MWh of electricity.

The local utility has provided electricity to the base using real-time pricing for 1998 through 2000. During this time the unit cost has varied from a high of $0.90 per kWh to a low of $0.009 per kWh. The average rate has been between $0.027 and $0.031 per kWh.

These estimated cost savings are attractive but are not a substitute for a rigorous economic evaluation. That detailed assessment is beyond the scope of this paper, but it would include energy costs based on terms of the contracts with the supplying utilities, equipment costs, installation costs accounting for site-specific factors such as natural gas compressors if necessary, electrical and mechanical interconnections, architectural and structural changes to existing buildings, ventilation systems, etc., gas turbine maintenance costs, and operator training.

TABLE 2
Results of Annual Performance Simulations for 82nd Steam Plant at Fort Bragg, North Carolina

Parameter	Baseline Gas Boilers		Gas Turbine	
Thermal Load	583.5 TJ	553,400 MBtu	583.5 TJ	553,400 MBtu
Simulated Heat Production				
a. gas turbine recovered heat	n/a	0 MBtu	495.2 TJ	469, 700 MBtu
b. boiler(s)	583.5 TJ	553,400 MBtu	88.3 TJ	83, 700 MBtu
c. total	583.5 TJ	553,400 MBtu	583.5 TJ	553,400 MBtu
Fuel Input				
a. gas turbine	n/a	n/a	1095.3 TJ	10.4×10^6 therms
b. boiler(s)	748.1 TJ	7.09×10^6 therms	113.2 TJ	1.1×10^6 therms
c. total	748.1 TJ	7.09×10^6 therms	1208.5 TJ	11.5×10^6 therms
Electricity Produced	0 MWh	0 MWh	86, 490 MWh	86, 490 MWh
CHP Annual Efficiency				
a. electrical	n/a	n/a	28.4%	28.4%
b. resource	78%	78%	73.6%	73.6%

Cooling

The analysis and results presented for the gas turbine installation have only included heat recovery for hot water distribution to the barracks and administrative buildings served by the 82nd Heating and Cooling Plant. While the recovered waste heat from two 3.5 MW turbines is sufficient to meet the summertime heating loads, it would be possible to generate electricity and heat with the third turbine in the summer and use the recovered heat to drive an absorption chiller. Chilled water can be used either as part of the district cooling system for the new barracks being served by the 82nd Plant or it could be used for turbine inlet air cooling. As mentioned previously, turbine capacity is a function of the temperature and density of the inlet air. Cooling the air before it enters the air compressor boosts the electrical output. Evaporative cooling is frequently used with mists or water sprays, but they are limited to reducing the air temperature to a few degrees below the wet-bulb. Mechanical cooling, as from an absorption chiller, can be used to bring the inlet air temperature down to 4°C to 6°C (40°F to 42°F) (Stewart 1999). Further information on the plant cooling loads is required in order to include either chilled water production or inlet air cooling in this analysis.

CONCLUSIONS

A series of statutes and executive orders keep "raising the bar" on federal agencies, requiring them to meet ever more challenging building energy use reduction goals. DOE's Federal Energy Management Program (FEMP) exists to help agencies meet their mandates. One of FEMP's strategies is to emphasize and support agencies' use of new technologies that promise substantial energy savings but are not well enough established in the marketplace to be readily accessible through routine acquisition processes. This year FEMP began to focus on cooling, heat, and power (CHP) systems of various types (advanced industrial turbines, microturbines, etc.).

Due to looming electricity supply problems, federal agencies are keenly interested in CHP as one of the very few technologies that adds to electricity supplies and increases energy efficiency. Agencies are moving aggressively to implement CHP projects and FEMP is participating in these efforts to provide unbiased and reliable documentation of costs, savings, and financial merit from the agency point of view. CHP projects at Fort Bragg, Gateway National Recreation Area, and Twenty-Nine Palms Marine Base are among these. Project development and implementation work at these sites is well underway. The FEMP evaluations are addressing technology performance and application engineering, as well as attendant issues—permitting, grid interconnection costs, exit fees, stand-by charges—that can make or break real projects.

The federal energy savings goals are largely non-funded mandates and therefore many agencies are turning to private financing when funding needs exceed their budgets. FEMP encourages and supports agency use of energy savings performance contracts (ESPCs) and utility energy service contracts (UESCs) to finance and implement building improvement projects. The financed cost is paid back over time from cost savings generated by the project—money that would have been spent anyway on wasted energy and maintenance and repair of obsolete equipment. ESPC and UESC investment has skyrocketed as these procurement vehicles have become better known and easier to use in the federal sector. The FEMP demonstration project evaluations are also addressing whether CHP systems are economical enough to be widely implemented using these pay-from-savings private financing authorities.

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