Energy - Docket Optical System

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Cc: Jennings, Jennifer@Energy
Subject: CEC record-Docket #11-AFC-03: Demand, Supply, and Transmission Problems
Attachments: NavyDealToREDUCEneed.pdf; Mirarmar using renewables.pdf; Letter_to_CPUC_on_SPPI_from_Navy_Pfannenstiel.pdf; VarghesePOS_DOS_0614.pdf

DOCKET
11-AFC-3
DATE JUN 14 2012
RECD. JUN 15 2012

CEC record-Docket #11-AFC-03 Quail Brush Power Generation Siting Case
Please post on the listserver.

ATTACHMENTS: 3

Dear CEC Commissioners, all on the POS list, and selected elected representatives:

I am forwarding the following article and 3 attachments to show that we are not in dire straits regarding power supply this summer or beyond, even without San Onofre. I am sure there are many other policies and practices that can be activated in addition to conservation; the Sunrise Powerlink; demand response mechanisms; and let's not forget the Navy's net-zero plans, their role in reducing their need, and even generating excess renewables as a matter of national security. Being the largest customer in San Diego, the Navy's use of power, their generation of renewables, and their problems with the transmission capacity (see letter to CPUC) should be seriously considered. They have the ability to generate excess renewable power that could supply some of the residential market, but because of transmission obstacles we are losing out on this supply. This problem should be seriously evaluated and real efforts made to resolve these instead of making the jump to building more gas-fired power plants (peaker or otherwise).

Please check out the attached article on how SDG&E expects to meet the summer's power needs. There is no doom anticipated in spite of scare tactics we have seen in the media lately.
http://www.sacbee.com/2012/06/14/4562438/sdge-expects-to-meet-summer-power.html

With thanks,

Roslind Varghese
Citizen Intervenor
roslindv@gmail.com

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228 – WWW.ENERGY.CA.GOV

APPLICATION FOR CERTIFICATION FOR THE *QUAIL BRUSH GENERATION PROJECT*

DOCKET NO. 11-AFC-03

PROOF OF SERVICE
(Revised 6/6/2012)

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DECLARATION OF SERVICE

I, Roslind Varghese, declare that on June 14, 2012, I served and filed a copy of NAVY documents and an article on SDG&E's power supply resolution (without San Onofre) for this summer, dated 6/14/12, 2012. This document is accompanied by the most recent Proof of Service list, located on the web page for this project at:

http://www.energy.ca.gov/sitingcases/quailbrush/index.html.

The document has been sent to the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit or Chief Counsel, as appropriate, in the following manner:

(C*heck all that Apply*)

For service to all other parties:

__X__ Served electronically to all e-mail addresses on the Proof of Service list;

___ Served by delivering on this date, either personally, or for mailing with the U.S. Postal Service with first-class postage thereon fully prepaid, to the name and address of the person served, for mailing that same day in the ordinary course of business; that the envelope was sealed and placed for collection and mailing on that date to those addresses **NOT** marked "e-mail preferred."

AND

For filing with the Docket Unit at the Energy Commission:

__X__ by sending an electronic copy to the e-mail address below (preferred method); ***OR***

___ by depositing an original and 12 paper copies in the mail with the U.S. Postal Service with first class postage thereon fully prepaid, as follows:

CALIFORNIA ENERGY COMMISSION – DOCKET UNIT
Attn: Docket No. 11-AFC-3
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OR, if filing a Petition for Reconsideration of Decision or Order pursuant to Title 20, § 1720:

___ Served by delivering on this date one electronic copy by e-mail, and an original paper copy to the Chief Counsel at the following address, either personally, or for mailing with the U.S. Postal Service with first class postage thereon fully prepaid:

California Energy Commission
Michael J. Levy, Chief Counsel
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Sacramento, CA 95814
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I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Roslind Varghese (electronic signature)

DEPARTMENT OF THE NAVY

THE ASSISTANT SECRETARY OF THE NAVY
(ENERGY, INSTALLATIONS & ENVIRONMENT)
1000 NAVY PENTAGON
WASHINGTON DC 20350-1000

President Michael R. Peevey
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

FEB 13 2012

Dear President ~~Peevey~~ Mike:

I am writing to follow up on our meeting last October regarding the Department of the Navy's (DoN's) regional smart grid initiative, the Smart Power Partnership Initiative (SPPI.) I would also like to bring to your attention a significant related issue – the barriers we are encountering as we attempt to achieve our, and the State's, renewable energy goals. It has become increasingly clear that some regulatory and/or legislative modifications will be needed for us to be able to accomplish the ambitious renewable energy goals shared by the DoN and the State of California.

On the SPPI, we continue to receive encouraging support from all involved stakeholders, including the Governor's Office, the Energy Commission, the ISO, and San Diego Gas and Electric (SDG&E), among others. We have a core team in place at our Naval Facilities Engineering Command Southwest in San Diego that is developing a pilot with the support of technical consultants and expertise from many of the stakeholders noted above. Working with SDG&E, we are preparing to conduct a series of demand response table top exercises and actual controlled load reduction events over the next few months. These tests will help us better understand the load aggregation and deferment opportunities we have across our DoN bases in the Southwest. I remain convinced that, working with our partners, we will demonstrate an effective regional smart grid that can be exported to other states and regions.

As we have said, one important attribute of a regional smart grid will be its ability to "share" renewable resources across the regional bases. That is especially evident in southern California where we have a few installations where the potential for renewable power generation significantly exceeds those installations' needs. It has been our intention to support the development of renewables beyond the requirements of a single base and be able to send the excess into the grid for use on other bases or elsewhere in the State.

Our commitment to the development of renewables on our bases was highlighted by President Obama's announcement in his State of the Union address that the Navy will purchase enough renewable energy to power a quarter of a million homes – or, as the

Secretary of the Navy has stated, DON will produce or purchase one gigawatt of renewable energy. We made this commitment because we recognize that energy security is fundamental to national security.

A large portion of the gigawatt of renewable energy is likely to come from our California bases in the form of new solar, wind, and geothermal development. However, the lack of transmission capacity, coupled with a number of regulatory and legislative requirements, have stymied our efforts to optimize the renewable potential of the California bases. The most serious issues we are confronting are described below.

- The single most critical impediment to our renewables development in California is the lack of transmission capacity in the vicinity of those installations with the best potential for renewable energy production. As an example, transmission constraints at our China Lake Weapons Station, adjacent to Ridgecrest, have limited development on that base to the 13.78 MW PV project currently under construction. This is unfortunate since there is a great deal more renewable energy potential at this location. We have been told by SCE that relief from this constraint will take 8 years.

- The current capacity limit for net electric metering (NEM) is 1MW. DoN installations are typically considered to be a single "site" or "premise" per application of the utilities' Rule 1 definitions; this severely limits the ability of installations to develop more than 1MW of renewables, regardless of the installation's load or capacity to support renewable projects. For example, a recently installed 1.5MW wind turbine at MCLB Barstow has been "turned down" to 1MW in order to qualify for the NEM program.

- In southern California, all existing generation must be retrofit with telemetry once the 1 MW threshold is crossed, which is a significant expense and deterrent. The telemetry is required even if the generation assets are well below the load of the installation and there is little prospect of export to the grid. For example, one installation is being required to install telemetry infrastructure (at a cost of over $800,000) on approximately 1MW of generation even though the minimum baseload is 8MW and there is almost no possibility of generation ever exceeding the installation's load.

- Standby and departing load charges discourage the development of RE by imposing significant costs that offset the savings from the renewable energy production. For example, the recently-awarded 14 MW project at NAWS China Lake, will cause the base to incur approximately $650,000 in departing load and $1M in standby charges annually. These charges will potentially be offset by a $2M reduction in demand charges, but the reductions will not be realized if the system does not produce at full capacity during times of peak demand.

We would like to work closely with you and the other stakeholders to consider how to address this set of issues. Specifically, and most urgently, we would like to see, and would commit to engaging in, a process that would resolve the transmission constraints at our installations. I would encourage you to personally lead a team that would consist of the Chair of the Energy Commission, representative(s) from the Governor's office, a senior representative from the ISO, and the DoN to focus specifically on the potential development of renewable resources at DoN installations in California. I have tasked my team in the Southwest to remain engaged with your office and others to help identify coordinated solutions.

The Department of the Navy has made a strong and significant commitment to the development of renewable energy. Our California installations are critical to meeting our renewables goals, as they are to meeting California's RPS. I ask that you make eliminating the barriers to renewables development for the Department of the Navy a high priority of the Public Utilities Commission. I look forward to working with you on this matter of national and state concern.

Jackie

Jackalyne Pfannenstiel

Copy to:
Mr. Michael Picker. Office of the Governor of California
Robert Weisenmiller, Chair, California Energy Commission
Mr. Wade Crowfoot, Deputy Director, Governor's Office of Planning and Research
Karen Edson, Vice President, Policy and Client Services, California ISO

Targeting Net Zero Energy at Marine Corps Air Station Miramar: Assessment and Recommendations

Samuel Booth, John Barnett, Kari Burman, Joshua Hambrick, Mike Helwig, and Robert Westby

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Technical Report
NREL/TP-7A40-47991
December 2010

Contract No. DE-AC36-08GO28308

NATIONAL RENEWABLE ENERGY LABORATORY

Targeting Net Zero Energy at Marine Corps Air Station Miramar: Assessment and Recommendations

Samuel Booth, John Barnett, Kari Burman, Joshua Hambrick, Mike Helwig, and Robert Westby

Prepared under Task No. IDOD.1010

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

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Acknowledgements

The National Renewable Energy Laboratory (NREL) thanks Randy Monohan and his energy team at Miramar Marine Corps Air Station for their cooperation and assistance in support of this work.

List of Acronyms

ACEEE	American Council for an Energy Efficient Economy
AC	alternating current
AHU	air handling unit
ARRA	American Recovery and Reinvestment Act
Btu	British thermal unit
CFL	compact fluorescent lighting
CHP	combined heat and power
CNG	compressed natural gas
CAES	compressed air energy storage
COP	coefficient of performance
CO_2	carbon dioxide
CSP	concentrating solar power
DC	direct current
DDC	direct digital controls
DG	distributed generation
DoD	U.S. Department of Defense
DOE	U.S. Department of Energy
DOTMLPF	Doctrine, Organization, Training, Material, Leadership & Education, Personnel and Facilities
ECIP	Energy Conservation Investment Program
ECM	Energy Conservation Measure
EPA	U.S. Environmental Protection Agency
ESPC	energy savings performance contract
EUI	The energy use index
FFV	flex fuel vehicle
ft^2	square feet
FY	fiscal year
FEMP	Federal Energy Management Program
GHG	greenhouse gas
GIS	geographic information system
GPM	gallons per minute
GSHP	ground source heat pump
HOMER	Hybrid Optimization Modeling Tool
HRSG	heat-recovery steam generator
HVAC	heating, ventilating, and air conditioning
IEEE	Institute of Electrical and Electronic Engineers
IESNA	Illumination Engineering Society of North America
IHSB	Island Hot Standby
kWh	kilowatt hours
kVA	kilo volt amperes
kV	kilovolt
LCOE	levelized cost of electricity
LED	light-emitting diode
MBtu	million British thermal units
MCAS	Marine Corps Air Station
MPR	market price referent

MSW	municipal solid waste
MWh	megawatt-hours
MW	megawatt
NaS	sodium sulphur
NAVFAC	Naval Facilities Engineering Command
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NEV	neighborhood electric vehicles
NiCad	nickel cadmium
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NZEI	net zero energy military installations
O&M	operation and maintenance
OSD	Office of the Secretary of Defense
PEM	proton exchange membrane
PPA	power purchase agreement
PV	Photovoltaics
PURPA	Public Utilities Regulatory Policy Act
REC	renewable energy credit
REO	renewable energy optimization
RE	renewable energy
SAM	Solar Advisory Model
SCF	Standard cubic feet
SES	Stirling Energy Systems
SGIP	Self Generation Incentive Program
SDG& E	San Diego Gas and Electric
TES	thermal energy storage
tCO_2e	tons of carbon dioxide equivalent
t	tons
UPS	uninterruptible power supply
VAV	variable air volume
VRLA	valve regulated lead acid
WBCSD	World Business Council for Sustainable Development
WRI	World Resources Institute
Wh	watt-hours
W	watts

Executive Summary

Defining a Net Zero Energy Military Installation

The Department of Defense (DoD) is the largest energy consumer in the U.S. government. Present energy use patterns impact DoD global operations by constraining freedom of action and self-sufficiency, demanding enormous economic resources, and in deployed environments, putting many lives at risk in associated logistics support operations. At the same time, there are many opportunities for DoD to more effectively meet their energy requirements through a combination of human actions, energy efficiency technologies, and renewable energy resources.

A joint initiative was formed between the DoD and Department of Energy (DOE) in 2008 to address military energy use. This initiative created a task force comprised of representatives from each branch of the military, the Office of the Secretary of Defense (OSD), the Federal Energy Management Program (FEMP), and the National Renewable Energy Laboratory (NREL) to examine the potential for net zero energy military installations. This report presents a net zero energy assessment of Marine Corps Air Station (MCAS) Miramar.

The concept of a net zero energy installation (NZEI) evolved from the definition of a net zero energy building. The task force initially defined a NZEI as: “A military installation that produces as much energy on or near the installation as it consumes in its buildings and facilities.”

MCAS Miramar was selected by the DoD/DOE Net Zero Analysis Task Force as the initial prototype installation for net zero energy analysis. Miramar was selected based on its strong history of energy advocacy and extensive track record of successful energy projects.

NREL expanded the initial definition of a NZEI in consultation with the task force and MCAS Miramar to clarify the focus on renewable energy and expand analysis to include fleet transportation fuel use. For the purposes of this assessment, a NZEI is defined as:

> “A military installation that produces as much energy on-site from renewable energy generation, or through the onsite use of renewable fuels, as it consumes in its buildings, facilities, and fleet vehicles.”

Note that tactical aviation fuel use is not addressed beyond identifying its baseline magnitude; there is currently no commercially available substitute for jet fuel.

Net Zero Energy is a concept of energy self-sufficiency based on minimized energy demand and use of local renewable energy resources. This contrasts with our current national dependence on imported fossil fuel. It may be seen as a design point useful to enter a disciplined exploration of how energy is provided and used. Defining a net zero energy military installation is complicated by the need to consider public facilities and infrastructure, how to treat energy used for various forms of transportation, and mission-specific energy requirements, such as tactical fuel demands.

A complete net zero solution considers all uses of energy within an installation for buildings, transportation, community infrastructure, industry, and other uses. NREL’s net zero energy assessment for Miramar focused on the following main areas:

- Energy and greenhouse gas baseline
- Energy efficiency measures

- Renewable energy potential
- Electrical system
- Transportation fuel use
- Energy project recommendations and implementation guidance.

The phased progression from a typical installation or community to an installation that has a reduced energy load to a renewably powered installation is illustrated in Figure 1.

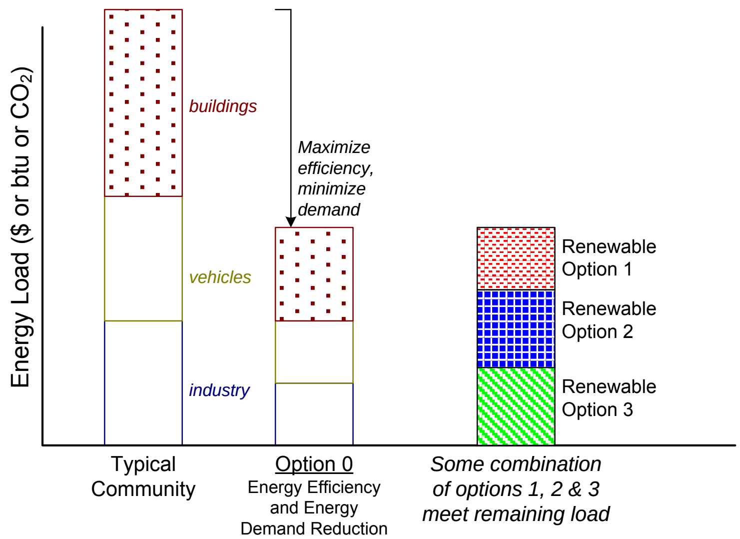

Figure 1. Net Zero Energy concept

Miramar's Energy Baseline

The first step in a NZEI assessment is to determine an energy baseline. The baseline is used to evaluate net zero energy potential. Working with the task force and MCAS Miramar, NREL determined an energy boundary for Miramar's baseline that includes all onsite buildings plus facilities (Main Base, Brig, Privatized Housing, and Commissary), and fleet vehicles. An energy baseline provides an analysis of current energy consumption on base, as well as a metric to measure progress against. Baseline energy consumption for Miramar is shown in Table 1.

Table 1. Miramar Energy Baseline

Baseline Annual Energy Usage Information	
Electricity (kWh)	66,543,615
Natural Gas (therms)	1,316,149
	Fuel (Gallons)
Gasoline	89,500
Diesel	10,000
Biodiesel	31,000
Compressed Natural Gas	45,000

The energy amounts above were converted to site Btu. The site Btu values were converted into source Btu using conversion factors developed by NREL. The total baseline energy usage at Miramar is ~870 billion source Btu.

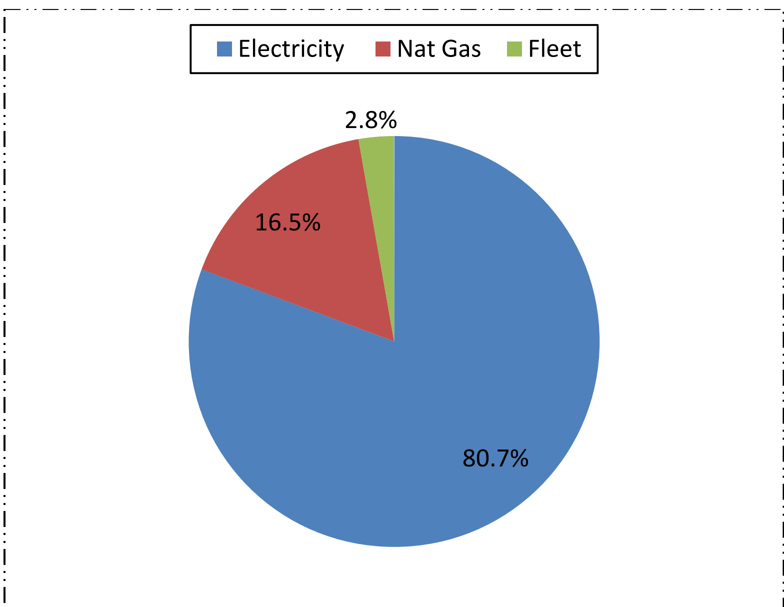

Figure 2. Miramar energy use breakdown (% of source total Btu)

Energy Project Identification

The second step in the net zero energy analysis was to evaluate the potential for energy projects on the base. NREL screened the energy efficiency opportunities, resources, and renewable energy potential at Miramar to begin determining the optimal energy project solution for Miramar.

Buildings

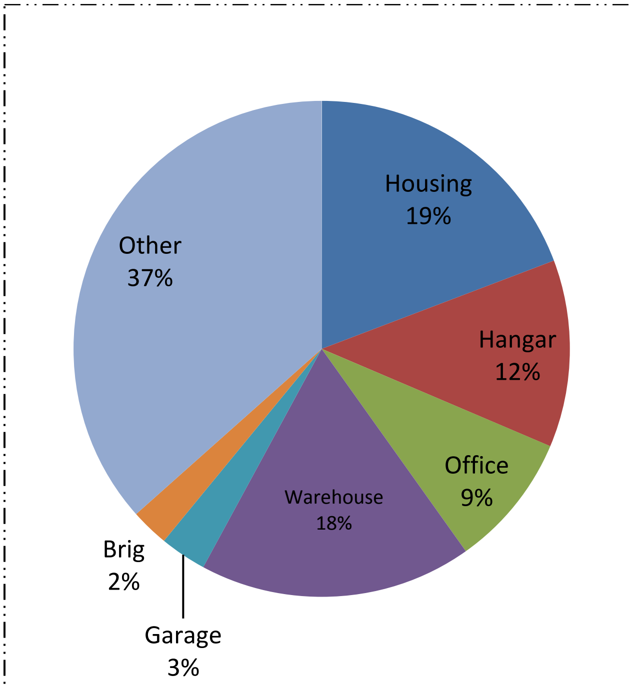

Figure 3. Miramar building portfolio breakdown

Buildings are responsible for the majority of the natural gas and electrical energy consumption at Miramar. While new buildings have the greatest potential to reach net zero energy status, building retrofits can also save a substantial amount of energy. A typical building can be retrofitted to reduce energy consumption by 30%.

Building energy efficiency was assessed for Miramar facilities in order to determine the potential for additional energy efficiency investment. The energy use index (EUI) for Miramar was calculated as 55 kBtu/ft.[2] This EUI value is quite low when compared to other buildings and indicates that the base is already managing its energy use well. The base has undertaken numerous energy efficiency projects; for example, the base has installed daylighting and lighting controls in some of the warehouses and hangars; it executed an energy savings performance contract (ESPC); and it enacted significant water conservation measures.

Figure 3 shows the percentage of square footage at Miramar occupied by a particular building type. The detailed table is provided in Appendix C.

Despite the base's already low EUI and past energy efficiency investments, there is still potential for the buildings at Miramar to become more energy efficient using cost-effective measures.

Renewable Energy Resource Assessment

NREL began its analysis of the renewable energy generation potential at Miramar by examining the high level resource potential. The analysis included Miramar-specific solar and wind resource maps, as well as national biomass and geothermal resource maps. Appendix G shows the renewable energy resource maps provided by the NREL geographic information system (GIS) group. *Overall, the maps indicate good solar resource potential, moderate geothermal and biomass potential, and poor wind potential.*

Renewable Energy Optimization

In addition to the basic resource assessment, the NREL team conducted an initial assessment of the renewable energy opportunities for Miramar based on high level energy, building, and resource data using NREL's Renewable Energy Optimization (REO) software tool. The initial screening evaluated the following technologies: photovoltaics (PV), wind, biomass gasifier/cogen, daylighting, solar thermal or concentrating solar power (CSP), solar hot water, solar vent preheating, and anaerobic digesters. The REO analysis determined the basic technical and economical feasibility of implementing these technologies at Miramar.

Several technologies were eliminated from further analysis and a proposed landfill gas power purchase agreement (PPA) was included in the analysis based on the resource assessment, REO screen, and discussions with Miramar. Technologies eliminated from additional analysis were: wind, solar vent preheat, and anaerobic digestion. Promising technologies to be further considered are: PV, solar thermal, ground source heat pumps (GSHP), solar hot water, daylighting, and biomass.

Energy Efficiency Analysis

It was beyond the scope of this project to conduct detailed energy audits of the approximately 800 installation facilities at Miramar. However, through discussion with base personnel, analysis of a previous ESPC proposal, and walkthroughs of several facilities, the savings potential for energy efficiency improvements at Miramar are estimated for numerous energy conservation measures, such as: lighting retrofits, building commissioning, and boiler replacement. NREL analyzed the projects already planned by the base, as well as potential additional projects. The estimated savings potential is shown below.

- Total electrical reduction = 10,676 MWh or 16.0% electrical load reduction
- Total natural gas reduction = 14,104 Site MBtu or 10.7% natural gas load reduction
- Total Btu reduction = 13.3% reduction.

Renewable Energy Analysis

NREL analyzed the potential for solar hot water, solar pool heating, concentrated solar power (CSP), PV, combined heat and power (CHP), and landfill gas at Miramar. NREL analyzed the projects already planned by the base as well as the potential for additional projects. Miramar has several projects planned to increase renewable energy generation. These projects will also help the base meet its Federal government and DoD energy mandates. These projects, which will continue to position Miramar as an energy leader, include the following:

- Purchase 3 MW of electricity from landfill gas generation project
- Install several solar hot water systems on several buildings
- Install 2.3 MW of PV on building rooftops and carports across the base
- Install 100 kW CSP system consisting of four 25 kW sterling dishes
- Install approximately 600 solar powered street lights across the base.

NREL is proposing additional projects that will cost effectively help Miramar progress toward NZEI status while providing environmental benefits and increased energy security.

- Install solar hot water systems on additional buildings.
- Install solar pool heating systems.
- Install 2.2 MW of PV on additional buildings and carports.
- Sign PPAs allowing for the installation of two 1.4 MW CHP fuel cells.
- Install daylighting systems on additional buildings.
- Install microturbines to provide CHP in several buildings.

Electrical Systems
NREL analyzed the high-level potential for the interconnection of renewable energy generation projects into the distribution system at Miramar. The proposed placement and interconnection of the recommended renewable energy systems was analyzed for conductor and protection device capacity. The relatively robust primary electrical distributions system at Miramar would allow the proposed projects to be tied into the distribution system anywhere on the primary feeders without significant upgrades to the base distribution system.

NREL simulated various configurations for distributed energy resources. Simulations covered hour-by-hour performance of the planned and proposed renewable energy generation systems and the coincidence of renewable energy generation and the hourly load profile at Miramar. The worst case scenario was reviewed for the minimum load and the maximum distributed generation (DG) on a given feeder. All feeders, including the main feeders from the utility, proved to be capable of handling the excess DG.

The net zero energy assessment also included analysis of a microgrid with DG sources to continue critical base operations (despite a disruption to the electrical grid). Implementing a microgrid with renewable energy, storage, and generators ensures the ability to continue critical operations in the event that an extended emergency occurs.

Transportation
The opportunity for transportation fuel savings was evaluated at Miramar. Miramar currently uses compressed natural gas (CNG) and biodiesel as alternative fuels for fleet vehicles onsite. E85, which is a fuel blend that is 85% ethanol and 15% gasoline, will soon be available near the base. It is recommended that Miramar use E85 fuel in its numerous E85-compatible fleet vehicles to reduce gasoline consumption. Additionally, Miramar should explore the potential to adopt and use more neighborhood electric vehicles (NEVs) and vehicle pooling to reduce the total fleet size.

Greenhouse Gas
A greenhouse gas (GHG) inventory was calculated for Miramar for scope 1 and scope 2 emissions. All of the energy uses included in the baseline were put into the GHG calculations. The base's GHG emissions baseline was approximately 30,183 tons of CO_2 per year. The base would achieve an 85% reduction in total GHG emissions by implementing the suggested renewable energy projects.

Implementation and Financing
Miramar has many potential avenues available for the implementation of energy projects. These include: ESPC, utility energy services contracts (UESC), PPAs, and appropriated funds. There are many issues that must be considered when selecting an implementation option, such as: the National

Environmental Policy Act (NEPA) review process, utility interconnection requirements, and the available incentives for renewable energy.

The projects currently planned by Miramar are exclusively appropriations-funded with the exception of the landfill gas project, which is a PPA for electrical energy.[1] The estimated capital costs for the appropriations funded projects are $35.4 million. The total NZEI source Btu reduction for the Miramar planned projects is 36%. These projects are shown in the tables below.

Table 2. Energy Demand Reduction Projects Planned by Miramar

Project Name	Project Size	Year	Reduction Amount
Boiler Replacement and Solar Hot Water	~30 Buildings and 70 boilers	2010	2,950 (MBtu) and 520 (MWh)

Table 3. Energy Generation Projects Planned by Miramar

Project Name	Project Size (kW)	Year	Est. Production (MWh)
Landfill Gas	3,000	2012	25,000
PV	2,362	2009, 2010, 2011	3,520
CSP	100	2011	394

The NREL proposed projects are being suggested as privately financed projects that will require no upfront capital from Miramar. The fuel cell project would be structured as a PPA that includes purchased electrical energy[2] and free thermal energy. Electrical and natural gas energy efficiency, solar hot water, daylighting, solar pool heaters, and microturbines would all be built into a single ESPC contract with an estimated total investment of $12 million. The additional PV could be either in the ESPC or a separate UESC or PPA; the estimated capital cost of the additional PV is $15 million. Alternatively, Miramar could fund these projects with appropriated funds. The capital costs in this scenario would be similar; however, some factors such as the availability of incentives would change. These projects are shown in Table 4.

[1] The final PPA price has yet to be determined. It will likely range between $0.09 and $0.13 per kWh.
[2] The final PPA price has yet to be determined. It is estimated to be approximately $0.13 kWh.

Table 4. NREL-Proposed Energy Projects

Electrical Load Reduction		
Project Name	**Year**	**Reduction Amount (MWh)**
Electrical Energy Efficiency	2011 and 2012	9,590
Daylighting	2011 and 2012	1,099

Additional Energy Generation Projects			
Project Name	**Project Size (kW)**	**Year**	**Production (MWh)**
Fuel Cell	2,800	2011 and 2012	23,000
PV	2,216	2012	3,300
Microturbines	115	2011 and 2012	1,005

Natural Gas Load Reduction		
Project Name	**Year**	**Reduction Amount (MBtu)**
Fuel Cell	2011 and 2012	53,814
Natural Gas Energy Efficiency	2011 and 2012	11,154
Solar Hot Water	2011 and 2012	4,570
Solar Pool	2012	6,700
Microturbines	2011 and 2012	(13,713)

Implementation of these additional energy projects along with the Miramar-proposed projects would result in a 90% NZEI source Btu reduction. The total modified source Btu breakdown for the base is shown below. The proposed energy efficiency and renewable energy projects comprise a reduction of approximately 92% of the original facility source Btu. For the fleet, the source Btu would be cut nearly in half from 23 million to 14 million.

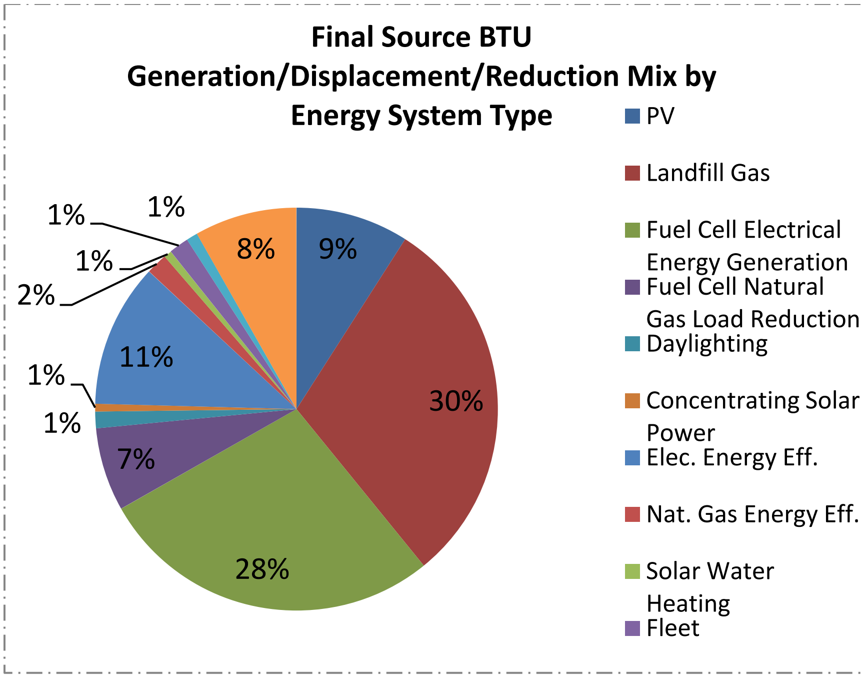

Figure 4. Final source Btu breakdown

Financial Analysis

NREL conducted a basic financial analysis of the recommended solution to approach net zero. This analysis simply provides a sample case and may not represent the actual financial costs of these recommendations. The actual costs and financial returns will be affected by additional factors, including: incentive availability, installation year, energy prices at the time of installation, Naval Facilities Engineering Command (NAVFAC) utility rates, and interconnection options.

NREL projected the future energy costs for Miramar (Figure 5). These estimated future costs for the base case scenario were compared to the costs of implementing the planned and recommended projects.

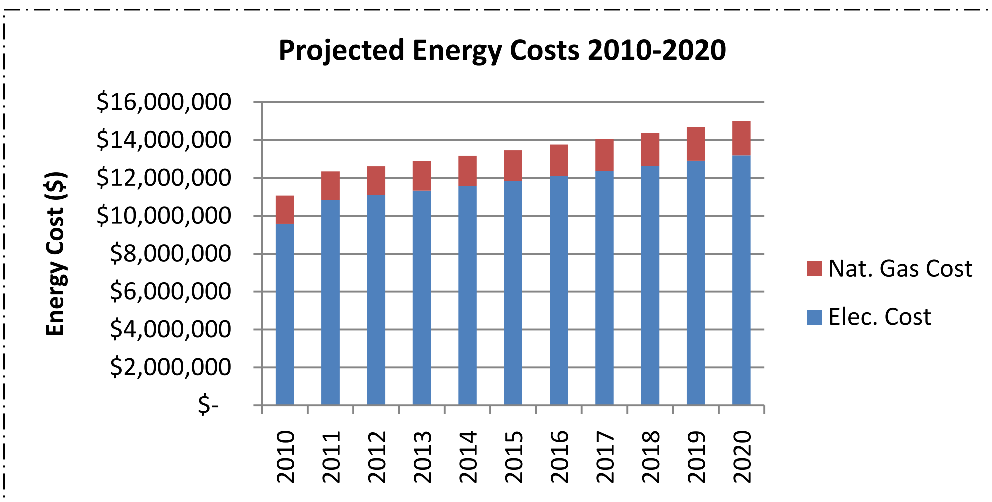

Figure 5. Projected energy costs

It was assumed that all energy efficiency and renewable energy projects other than the fuel cell would be implemented under an ESPC contract. NREL's Scenario Builder ESPC Financial Analysis Tool was used to approximate ESPC contract prices. The results from this tool yielded a direct expense of $24 million and total investment cost of $32 million for the following Energy Conservation Measures (ECMs):

- Natural and electrical gas energy efficiency
- Daylighting
- Solar hot water
- Solar pool heater
- Microturbines
- Photovoltaics (PV).

The total investment cost includes additional items, such as monitoring and verification, management and administration, and profits that are not included in the direct cost. The simple payback of the total investment was 14 years.

NREL developed a payment schedule from this tool. The payment required varies from year to year; however, the average payment over the 16-year contract lifetime is $2.6 million. This payment stream was built into a larger financial analysis that included the PPA project payments and the capital costs for the projects already planned by Miramar.

The results from this analysis illustrate that this set of energy project recommendations is likely to be viable under a 20-year project lifetime and would provide reduced energy costs to the base. The annual cost of the baseline scenario was compared to the annual cost of the recommended scenario over a 20-year period.

The graph below shows that there are no savings in 2010 or 2011 as the capital costs for the Miramar-initiated projects are expended. Annual costs are included for the fuel cell and landfill gas PPA agreements, NAVFAC utility services, and San Diego Gas and Electric (SDG&E) standby and departing load charges. In 2012, the base begins to see savings from the energy project investment compared with the base case. Over the 20-year lifetime that was analyzed, the savings are $26 million and the net present value is $6.7 million. The annual savings from this scenario are shown in Figure 6.

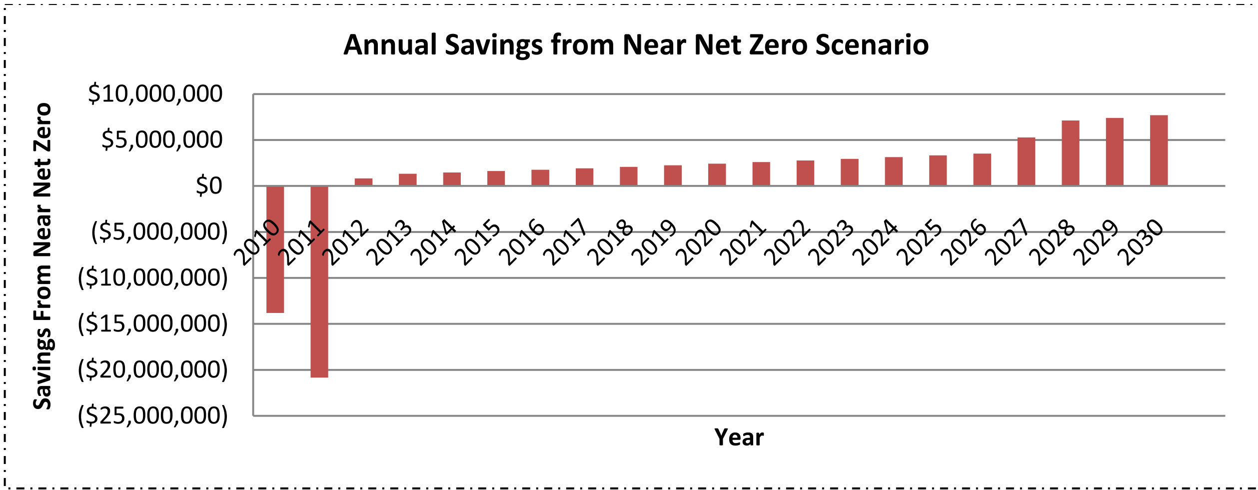

Figure 6. Projected savings from recommended scenario

This analysis depends on many estimated factors, such as inflation rate, energy price escalation rates, and natural gas prices. These factors can substantially affect the estimated cost savings, as well as the Net Present Value (NPV), both positively and negatively. However, this financial analysis shows that under a variety of scenarios, the recommended energy projects will allow the base to move closer to NZEI status and will likely reduce energy costs for Miramar.

Conclusion

The analysis conducted by NREL shows that MCAS Miramar has the potential to make significant progress toward becoming a net zero installation for its facilities and buildings. If the recommended energy projects and savings measures are implemented, a 90% source Btu reduction will be achieved by the base. Net zero energy status is within reach if Miramar implements the recommended measures, replaces all remaining natural gas with an available renewable natural gas, and switches the government transport fleet to renewable fuels or to electric vehicles as these become more widely available. By achieving net zero energy status, the base will set an example for other military installations, increase mission capabilities, provide environmental benefits, reduce costs, increase energy security, and exceed its energy goals and mandates.

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1 Introduction

In 2008, the Department of Defense (DoD) and Department of Energy (DOE) defined a joint initiative to address military energy use by identifying specific actions to reduce energy demand and increase use of renewable energy on DoD installations. A Task Force comprised of representatives from the Office of the Secretary of Defense (OSD), the four military Services, DOE's Federal Energy Management Program (FEMP), and the National Renewable Energy Laboratory (NREL) was established. In light of DoD priorities, early attention was given to the possibility of net zero energy military installations (NZEI), that is, installations that would meet their energy needs with local renewable resources. Marine Corps Air Station (MCAS) The Task Force selected Miramar to be the prototype installation for net zero energy assessment and planning. This selection was based on Miramar's strong history of energy advocacy and extensive track record of successful energy projects.

NREL was tasked to perform a comprehensive, first-of-its-kind assessment of Miramar's potential to achieve net zero energy status, provide energy project recommendations, and then to develop a template based on this work that could be used for other military installations.

1.1 Overview of the DoD Energy Context

The Department of Defense (DoD) is the largest energy consumer in the U.S. government. Present energy use patterns impact DoD global operations by constraining freedom of action and self-sufficiency, demanding enormous economic resources, and putting many lives at risk though associated logistics support operations in deployed environments. There are opportunities to more effectively meet DoD energy requirements through human actions, energy efficiency technologies, and renewable energy resources. DoD's corporate hierarchy offers implementation advantages in both speed and scale: the military has often been a market leader in the adoption of new technologies and complex systems. DoD leaders' present focus on exploring improvements to energy provision and use in the departments operations—at home and abroad—is timely.

In fiscal year (FY) 2008, the DoD consumed 889 trillion site-delivered Btu and spent on the order of $20 billion on energy. The majority of DoD energy consumption is fossil fuel based (coal, oil, natural gas, or electricity produced from these), often from foreign sources. The DoD accounts for about 1.8% of total United States petroleum consumption and 0.4% of the world's consumption. A summary of DoD energy use is shown in Figure 7. This report focuses on the 26% of energy used in buildings subject to Federal energy mandates,[3] buildings exempted from these mandates, and fleet vehicles. Tactical fuel use is not considered at this time.[4]

[3] Federal Buildings are subject to mandated energy efficiency reductions under the National Energy Conservation Policy Act (NECPA) and Executive Order 13423. Some buildings are exempt from these requirements. Guidelines for exempting buildings can be found here: www.eere.energy.gov/femp/pdfs/exclusion_criteria.pdf.

[4] Alternative fuels are in development and testing. Also, tactical fuel use can be reduced through reduction in tactical system use (for example, in favor of simulator-based training), and through application of energy-saving technologies (e.g., skin coatings for aircraft and ships, improvements in aerodynamic/hydrodynamic design, hybrid drive systems for ground vehicles).

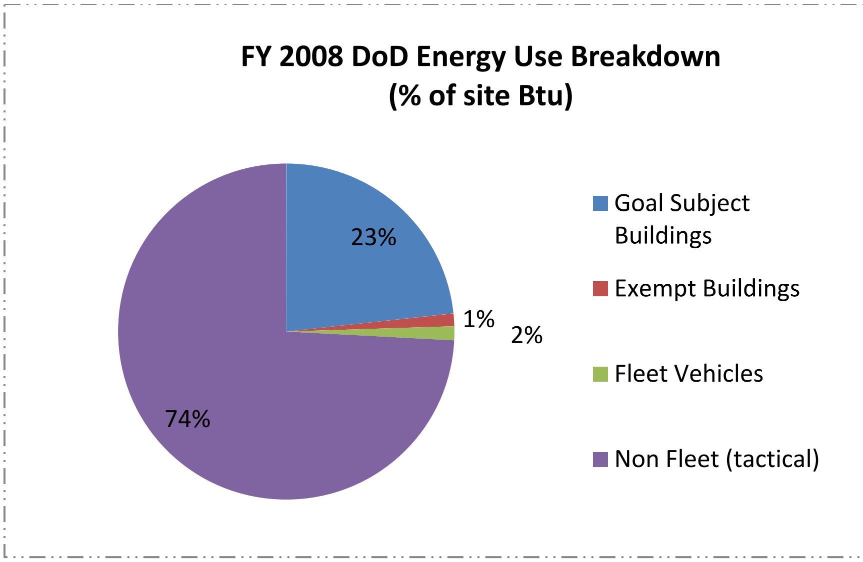

Figure 7. DoD energy use breakdown

1.2 Energy Strategies for DOD Installations: Key Considerations

A NZEI assessment is a framework for a military installation to develop a holistic and systematic energy strategy. An installation's energy strategy should reflect a number of constraints and considerations:

- ***Mission Compatibility***. Mission accomplishment is the top priority when considering energy strategies. Even if attractive by other measures, a proposal that is incompatible with the installation's mission will be eliminated. Wind turbines sited near a runway are one example of an energy technology incompatible with the flying mission at many military installations such as Miramar.
- ***Security***. An installation's energy system must maintain or enhance energy security, surety and reliability, and overall physical security of the site must be maintained. For example, a biomass-fueled power system may be inappropriate for some sites due to offsite truck traffic required to bring in fuel. However, the ability to meet an installation's critical load using onsite renewable sources (e.g., landfill gas, geothermal power, solar energy) in an islanding mode may greatly enhance energy security. This is underscored not only by the threat of malicious activities (e.g., physical or cyber attacks), but also by possibility of major blackouts. Blackouts have occurred in the U.S. many times in recent decades, and more are anticipated, due to the aging electric grid infrastructure, decreased maintenance investment, increasing loads, and the lack of situational awareness on the part of grid operators.[5] A recent Defense Science Board report stated that critical military missions are at a high risk of failure in the event of an electric grid failure.[6] The development of onsite energy supplies and smart microgrids, which are part of a net zero energy solution, can reduce this risk, and may become an increasingly important strategic concern.

[5] The Smart Grid, An Introduction. U.S. Department of Energy. No.DE-AC26-04NT41817, Subtask 560.01.04, www.doe.energy.gov/DocumentsandMedia/DOE_SG_Book_Single_Pages.pdf. Accessed April 2010.
[6] More Fight Less Fuel, Defense Science Board Report. Febuary, 2008. www.acq.osd.mil/dsb/reports/ADA477619.pdf. Accessed May 2010.

- ***Economics***. Life-cycle, system-based economic energy strategy assessments should reflect factors including technological maturity; fuel availability and cost; energy storage requirements; distribution and interconnection arrangements; financing options; Federal, state, and local incentives; environmental impacts; and costs for operations and maintenance (O&M).
- ***Agency Goals and Federal Mandates***. The DoD has a strategic energy plan to reduce consumption, leverage new technologies, drive personnel awareness, and increase energy supply. A primary goal is to achieve 25% renewable electrical energy use by 2025. In October 2009, the Secretary of the Navy stated a new goal: by 2020, 50% of the energy consumed by ships, aircrafts, tanks, shore vehicles, and installations should come from alternative sources.[7] Federal mandates presently focus on energy efficiency and renewable energy goals. These are planned to be expanded in the near future to include carbon emission targets.
- ***Site Resources***. Energy system siting opportunities vary among installations, as do local climate, renewable energy resources, and electrical system interconnection opportunities.
- ***Doctrine, Organization, Training, Material, Leadership & Education, Personnel and Facilities (DOTMLPF)***. Over time, holistic change to DoD energy systems, technologies, and practices will involve new doctrine, adjustments to organizations and training, new acquisition methodologies, leadership by example, and updates to education systems.

The contribution of a net zero energy assessment to the development of site-specific energy strategies responsive to these constraints is discussed below.

1.3 NZEI Concept

Net Zero Energy is a concept of energy self-sufficiency focused on use of local renewable energy resources and minimized demand. While net zero energy status *in itself* is not inherently a high priority for DOD installations, it can serve as a design point well suited to a disciplined exploration of how energy is provided and used. First developed in the context of individual houses, for which the challenge is to provide all required energy using onsite renewable resources, the concept has been extended in recent years to communities, campuses and installations. In principle, a net zero energy installation should reduce its load through conservation and energy efficiency, then meet the remaining load through onsite renewable energy. Defining a net zero energy military installation is complicated by the need to consider, in addition to individual buildings, public facilities and infrastructure--the questions of how to treat energy used for various forms of transportation, and mission-specific energy requirements, such as tactical fuel demands.

The net zero energy concept is illustrated in Figure 8.

[7] Naval Energy Forum. October 14, 2009. http://osiris.usnwc.edu/pipermail/nwc_onlinediscussion/attachments/20091119/9d999c42/attachment.obj. Accessed April 1010.

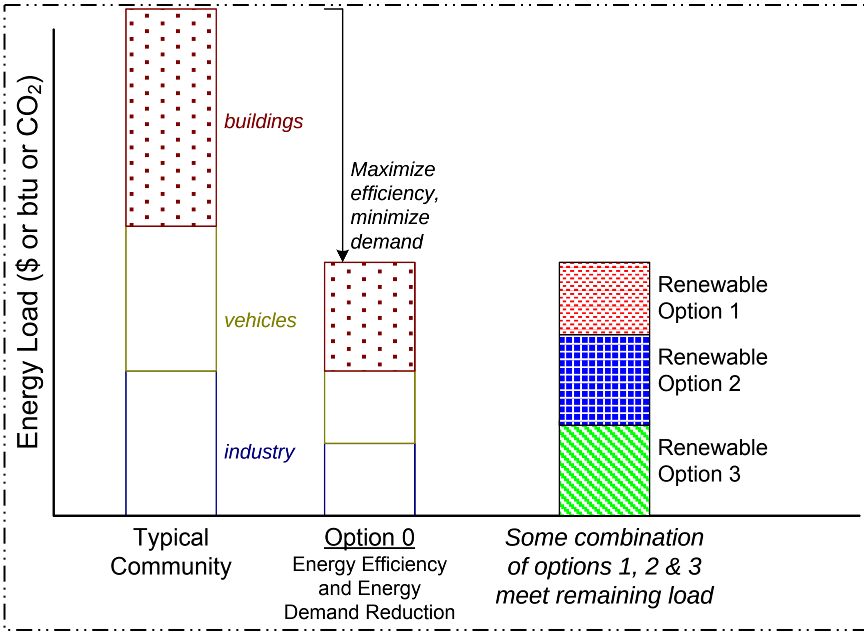

Figure 8. Net zero energy installation concept

The original definition of a net zero energy installation adopted by the DoD-DOE Task Force was, "An installation that produces as much energy on or near the installation, as it consumes in its buildings and facilities." The definition was elaborated in consultation with the task force and MCAS Miramar to focus on renewable energy, on-site generation, and fleet fuel use. The following definition was used for this assessment:

> "A net zero energy military installation produces as much energy onsite from renewable energy generation or through the onsite use of renewable fuels, as it consumes in its buildings, facilities, and fleet vehicles."

A more detailed explanation of this elaboration and the net zero definition is given below:

- "Net Zero" means that the energy produced onsite over the period of a given year is equal to the installation's energy demand. This implies a connection to a local power grid, which "banks" the energy. Thus, an onsite solar energy system, for example, may produce energy greater than that used by the installation during the day, feeding excess energy into the local grid. At night, when the solar system is not producing energy, the installation relies on energy from the grid.
- Energy consumption may be in the form of electricity, hot or chilled water, steam, or direct use of fuel.
- A military installation is any facility, which may be a contiguous area or may comprise separate areas. When assessing the energy of the installation, all activities within the defined boundaries are included, regardless of whether their energy is managed by the base energy manager or paid for by different agencies.
- The Task Force's willingness to include energy production "on or near the installation" was left open to interpretation. The assessment team focused primarily on the possibilities of onsite energy production, accepting the following forms of energy: energy generated onsite from renewable sources and renewable fuel used onsite. The set

of onsite renewable energy sources followed standard DOE practice: commercially available solar (photovoltaic, concentrating solar power, water heating), wind and hydropower systems, and electricity or heat generated from natural gas produced in onsite landfills or by burning the installation's trash (trash-to-energy or municipal solid waste).

- Renewable fuels include various forms of biomass (wood waste, agricultural byproducts); natural gas (produced from external landfills or as a byproduct of sewage processing); and various renewable transportation fuels (ethanol- E85, biodiesel).
- As employed here, the net zero energy concept does not include non-primary energy imported from offsite (e.g., electricity from a local offsite renewable source), or purchases of renewable energy credits (RECs), that is, getting credit for RE generation somewhere else in the world. This is consistent with the NZEI concepts' emphasis on meeting energy needs with local resources.
- The Task Force definition does not explicitly discuss minimizing the installation's load, an essential first step toward net zero energy status. This can be accomplished through human actions to conserve energy or reduce energy waste, or by identifying approaches to conserving energy without impacting the mission. This also includes the implementation of standard facility energy efficiency technologies that are economically feasible. These may include heating, ventilation and air conditioning (HVAC) and lighting upgrades (efficient chillers and boilers, solar ventilation pre-heat, fluorescent or light-emitting diode (LED) lighting); environmental control systems; systems generating both electricity and heat (cogeneration systems); and building envelope upgrades or design features such as insulation, high-performance windows, and daylighting.
- Installation energy consumption can be measured several ways. Possible measurement approaches include.[8]
    - Net Zero Site Energy: Energy used by the installation is accounted for at the site, for example, as indicated by building electricity and gas meters. This approach is a simple measurement, but omits transmission losses to bring energy to the site.
    - Net Zero Source Energy: Source energy refers to the primary energy used to generate and deliver the energy to the site, for example by a local utility generation site and transmission system. For transportation fuel, source energy includes a multiplier to account for the energy required to transport the fuel to the fueling station.
    - Net Zero Energy Costs: The amount of money the utility pays the installation for renewable energy generated onsite and exported to the grid is compared with the amount the owner pays the utility for energy used over a year.
    - Net Zero Energy Emissions: The installation aims to produce and use at least as much clean renewable energy onsite as it uses from offsite local energy sources annually, offsetting the offsite emissions.

[8] Torcellini et al. *Zero Energy Buildings: A Critical Look at the Definition*. Golden, Colorado: National Renewable Energy Laboratory. June 2006, www.nrel.gov/docs/fy06osti/39833.pdf.

For this assessment, the Source Energy method was selected as the basis for energy accounting because it is the most representative measure of primary energy consumption.

- Transportation fuel use is included with the following limitations: All available transportation fuel consumption data are gathered for the purpose of establishing an installation's total carbon footprint. This can include government ground fleet vehicle fuel use, fuel associated with commercial air travel for official business, fuel used in personnel commuting, and tactical fuel use. However, only the government fleet use is further addressed in the NZEI. Potential reduction measures include converting to electric vehicles, using electricity generated onsite from renewable sources, or using renewable fuels in fleet vehicles.

  Since the DoD's ability to influence the energy used in commercial air travel and by commuters is limited to minimizing trips, encouraging carpooling or telecommuting, or providing electric vehicle charging stations to encourage employees to consider electric vehicles when they become widely available, these measures are not considered. Tactical fuel requirements are not addressed in the assessment because renewable fuel alternatives are not yet commercially available. DoD can (and does) examine training requirements and opportunities to use simulators (instead of real tanks, aircraft, ships and submarines) and also to explore logistical variations that can reduce fuel use. These options are not addressed in this report.

  Again, the net zero energy installation concept can guide an exploration of demand reduction through human action and energy efficiency technology, while meeting remaining energy needs with local renewable energy resources. Some installations will be able to exceed net zero status to become net energy producers, while others won't be able to approach it. In fact, a net zero goal too strictly applied can lead to solutions that make poor sense from economic or other perspectives. However, assessment of a site's net zero potential, that considers the relevant constraints, identified in the preceding section, provides a disciplined basis for identifying an optimal energy strategy tailored to the requirements of each site.

1.4 Assessment Approach

The approach developed for this assessment includes seven steps, which are briefly summarized below and addressed in detail in the remaining chapters of this report.

1. **Establish MCAS Miramar Energy Baseline** (Section 2): Identify the installation mission, geographic boundaries, and any special energy requirements (e.g., reliability, performance in emergency situations, etc.). Summarize annual (source) energy used by all identified sources supporting the mission, its type and means of distribution. Become familiar with energy projects already planned onsite.

   A GHG baseline assessment is included for later comparison with the emissions projected for the recommended future energy system. There are currently no formal GHG emission reduction requirements, but new requirements may be instituted in the near future.

2. **Energy Project Screening** (Section 3): Collect the data needed to identify energy efficiency and renewable energy projects onsite, and possibilities for increased use of renewable fuel by the government fleet.

3. **Energy Efficiency Project Assessment and Recommendations** (Section 4): Identify specific onsite energy efficiency projects and their effect on installation energy demand.
4. **Renewable Energy and Additional Load Reduction Projects** (Section 5): Identify projects exploiting onsite renewable energy for electricity and heat production, or employing renewable fuels onsite for electricity production or for fleet transport.
5. **Electrical Systems Assessment and Recommendations** (Section 6): Identify the impacts of recommended onsite renewable energy projects on the installation's grid. As required by the installation, outline the characteristics of a smart microgrid to support emergency operations in the event of a public grid outage.
6. **Characterize Miramar's Net Zero Energy Potential** (Section 7): Bringing together findings from the preceding sections, calculate the extent to which the installation can approach net zero energy status. Then, with reference to broader installation and mission constraints, recommend a set of energy projects.
7. **Outline Implementation Steps (Project Planning and Financial Assessment)** (Section 8): Demonstrate how the recommended projects, in concert with projects already planned by the installation, can be implemented, with attention to timelines and financing alternatives.

2 MCAS Miramar Energy Baseline

2.1 Overview

The first step in a NZEI assessment is to determine an energy baseline that will be used to evaluate net zero energy potential and serve as a reference point for measuring progress. An energy baseline provides an analysis of energy consumption on base.

2.2 Total Consumption Breakdown

Working with the task force and MCAS Miramar, NREL determined an energy boundary for Miramar's baseline that includes all onsite buildings and facilities, and government fleet vehicles.

There are additional uses of energy on the base that were not included in the NZEI analysis but were provided to NREL by the base. These energy uses are discussed below to establish a more complete picture of the total energy footprint of the base. Commuter fuel use was estimated at 2,500,000 gallons of gasoline per year and tactical flying mission fuel use was estimated to be 29,000,000 gallons of JP-5 jet fuel. NREL was not able to determine the footprint from commercial flights taken by base personnel, however, this is another energy use that could be analyzed. Additionally, several of the hangar buildings at Miramar use propane for space and water heating. However, NREL was unable to obtain propane consumption data for these buildings. All of the energy usages mentioned above were converted to Btu for the purpose of summarizing the total base energy consumption. The total base energy use is 5,600 Billon source Btu. Figure 9 shows total base energy use in terms of percent of source Btu.

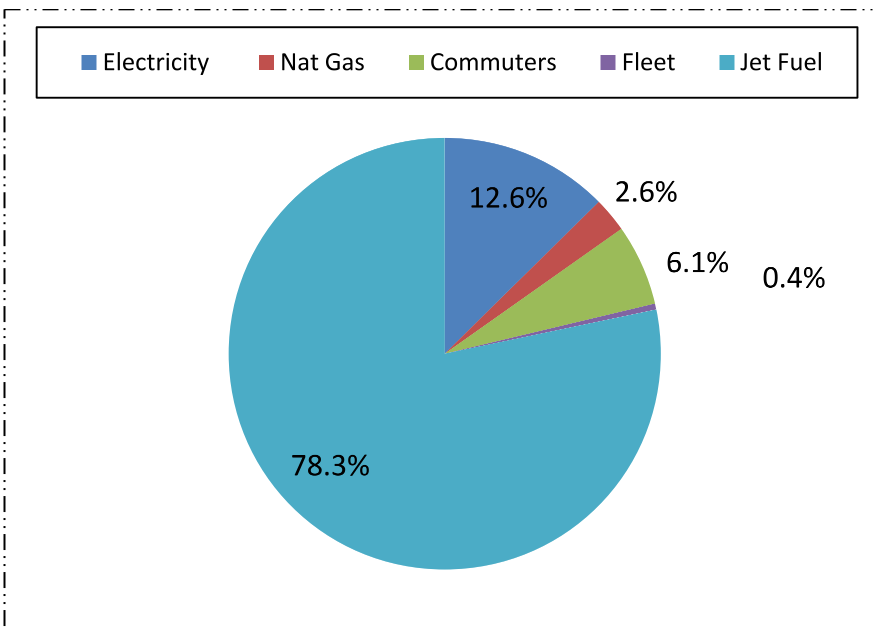

Figure 9. Total energy use at MCAS Miramar including all fuel use

Figure 9 shows that tactical jet fuel use comprises approximately 78% of the energy use on base. Fuel use for commuters also comprises a significant fraction of energy use at 6.1%. Examination of these fuel uses was out of the scope of the NZEI analysis, which focused on buildings and fleet vehicles. The amounts of fuel used for tactical operations and by commuters are outside of the control of the installation energy managers. Additionally, there are currently no commercially available alternatives to jet fuel that could be used in tactical flight operations. While not examined in this project, the potential to reduce the use of fuel in flight operations and commuting vehicles presents opportunities for future analysis.

The baseline energy consumption for the net zero energy analysis at Miramar is shown in Table 5.

Table 5. Miramar Energy Baseline

Baseline Annual Energy Usage Information	
Electricity (kWh)	66,543,615
Natural Gas (therms)	1,316,149
Fuel (gallons)	
Gasoline	89,500
Diesel	10,000
Biodiesel	31,000
Compressed Natural Gas	45,000

The energy amounts above were converted to site Btu. The total site Btu were 379 Billon. These site Btu values were converted into source Btu using conversion factors developed by NREL. The total baseline energy usage at Miramar is 870 billion source Btu.

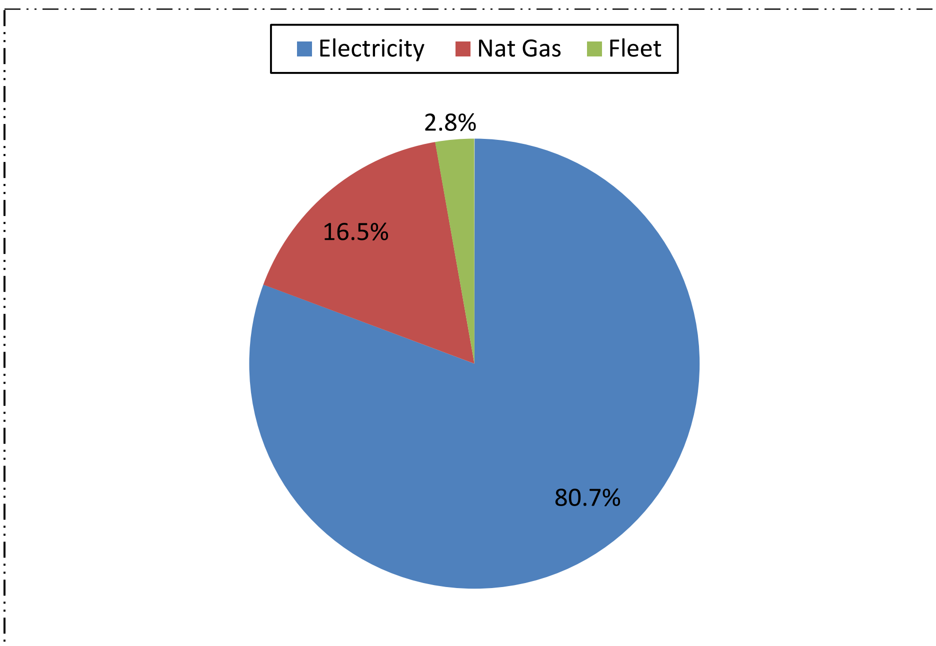

Figure 10. Miramar energy use breakdown (% of total source Btu)

The total base energy consumption is 379 billion site-delivered Btu. Many people are familiar with site Btu or site energy, which is the amount of fuel and electricity consumed and reflected in utility bills. However, energy may be delivered to a facility as either primary or secondary energy. Primary energy is raw fuel that is burned onsite to create heat or electricity. Secondary energy is the product of the combustion of the raw fuel as thermal energy or electricity. It is not possible to directly compare primary and secondary energy because the former is a raw fuel and the latter is a product of combustion of the raw fuel.[9] This assessment uses source energy as the common metric for analysis. This permits comparison of the two energy types, and better supports assessment of DoD goals for fossil fuel reduction and renewable energy generation. A source Btu analysis enables accounting of the energy required to transport fuel to the base and the energy loses due to inefficiencies in the electrical generation process. For raw fuels, the difference between site and source energy is minimal and accounts for fuel distribution and dispensing but not fuel production. For example, diesel fuel losses for fuel transport, storage, and dispensing are accounted for, but energy used in extracting crude oil and refining it into diesel fuel is not accounted for. The same basic analysis applies for electricity: losses in producing the fuel to be combusted for electrical energy production are not accounted for; however, the losses in the conversion of a primary chemical fuel (such as coal) to a secondary fuel (such as electricity) are accounted for.

Calculating a conversion factor to translate between site and source Btu for a specific installation can be difficult. The exact ratio depends on many factors, such as the location of the installation, the efficiency of the energy distribution system, and the location from which the installation's energy is sourced. For example, the exact electrical energy conversion factor depends on the specific power plant from which an installation receives its energy, its efficiency, and its proximity to the installation. Analyzing a site-to-source conversion in this manner will penalize or credit an installation based on the relative performance of its electrical energy source. It would be unfair and impractical to trace installation energy use down to the level of a specific power plant. However, using a regional site-source ratio accounts for the electrical generation mix of the area where an installation is located. This analysis used a California-specific electrical site-to-source ratio and national ratios for fuel delivered to buildings. The ratios are shown in Table 6.

Table 6. Site-to-Source Energy Ratios[10]

Energy Type/Fuel	Site-to-Source Ratio
Electricity	3.095
Natural Gas	1.092
Gasoline	1.187
Diesel Fuel	1.158

The national conversion factor for electricity used by DOE is 11,850 Btu consumed per kWh produced (a ratio of 3.47). This accounts for the following losses: energy lost in the generation process (66.5%), electricity used in the utility plant (1.7%), and electricity lost in the transmission and distribution process (3.0%). The amount of net electrical energy reaching the site is reduced to 3,413 Btu or 28.8% of the total. Thus, 71.2% of the energy is lost in the conversion from primary raw fuel to secondary electrical energy. The electrical generation mix in California contains more natural gas and more renewable energy than the national average, accounting for the reduced site-to-source ratio for electrical energy used in this analysis.

[9] Explanation of site and source Btu adapted from "ENERGY STAR Performance Ratings Methodology for Incorporating Source Energy Use." U.S. EPA, August 2009. www.energystar.gov/ia/business/evaluate_performance/site_source.pdf.
[10] Deru, M.; Torcellini, P. Source Energy and Emission Factors for Energy Use in Buildings. NREL/TP-550-38617. Golden, CO: National Renewable Energy Laboratory, June 2007.

2.3 Electrical Baseline

The electrical energy baseline consumption for Miramar was estimated using data received from the base energy manager, NAVFAC, the Defense Commissary Agency, the Miramar Brig, and Lincoln Military Housing. The electrical load for the clinic was estimated. The total estimated annual electric consumption is provided in Table 7. The Main Base consumption includes data for facilities that Miramar is required to report to the DoD. The correction shown at the bottom of the table accounts for facilities not being reported, estimation errors, and potential load growth.

Table 7. Electrical Consumption Baseline

Load Locations	Annual Electric Consumption (MWh)
Main Base	49,341
Clinic	507
Commissary	3,899
Brig	2,657
Privatized Housing	4,090
Total Other Loads	11,153
Grand Total	60,494
Correction and Load Growth (+10%)	6,049
Final Baseline	66,544

In addition to determining consumption, the electrical load profiles provided by Miramar's advanced meters, as well as Miramar's electrical distribution system, were examined for two scenarios: 1) Grid Connected and 2) Microgrid (islanding). The electrical baseline loads will be discussed separately, as the islanding scenario will address only the critical loads.

The California Energy Commission's *California Commercial End-Use Survey*[11] was used to estimate the end use of Miramar's electric consumption. The values used are for buildings in the Southern California Edison service territory; however, it was assumed that the energy use breakdown for these buildings would be similar to energy use at Miramar. The survey gave values in terms of kWh per square foot per year of electrical energy usage by building type for heating, cooling, ventilation, refrigeration, cooking, interior lighting, exterior lighting, office equipment, and miscellaneous. These data, along with data from the building portfolio at Miramar, were used to estimate an end use profile based on the building types. The figure below shows the estimated end uses of electricity at Miramar. Additional details can be found in Appendix D.

[11] California Energy Commission. *California Commercial End-Use Survey*. CEC-400-2006-005. March 2006.

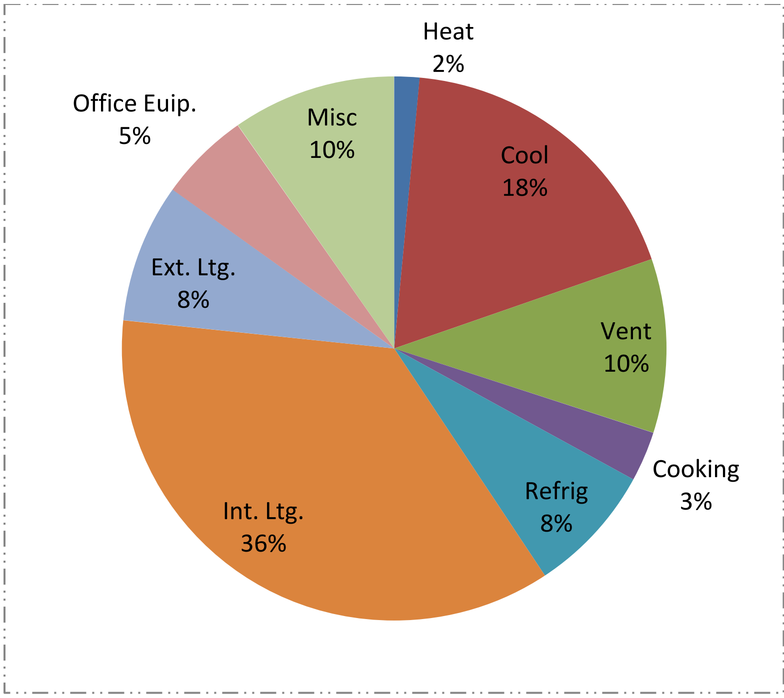

Figure 11. Estimated end use of Miramar electrical load-grid connection

NAVFAC provides Miramar with four sets of matched radial 12 kV feeders that are tied into auto-loop distribution systems on the base. The auto-loop systems are more reliable than a simple radial distribution system because the auto-loop can sense the loss of one source of voltage and automatically switch the load to the second feeder. San Diego Gas and Electric (SDG&E) has two advanced meters that monitor the power delivered to the base every 15 minutes.

NAVFAC manages the electrical utility services and distribution network for the Marine Corps on the Main Base at Miramar. SDG&E monitors and provides utilities to several select buildings at Miramar, including the Commissary and the Brig. For this study, NREL has combined the electrical baseline to include the Main Base load and the electrical use from the Clinic, Commissary, Brig, and Privatized Housing. The total annual electrical energy use obtained from NAVFAC and various billing statements for was 60,494,195 kWh. A 10% increase in this energy was added to account for exempt buildings, errors in metering, potential load growth, and possible electric fleet addition. An annual baseline energy use of 66,543,614 kWh/yr is used as the overall base-case electrical load.

Meter data received from June 1, 2008 to May 31, 2009 and adjusted for the 10% increase demonstrate Miramar's average annual electrical load of 7,596 MW. The peak load of 13,483 MW occurred on October 1, 2008 and the minimum load of 5,389 MW occurred on January 1, 2009.

Figure 12 illustrates the primary base load and the frequency of occurrence.

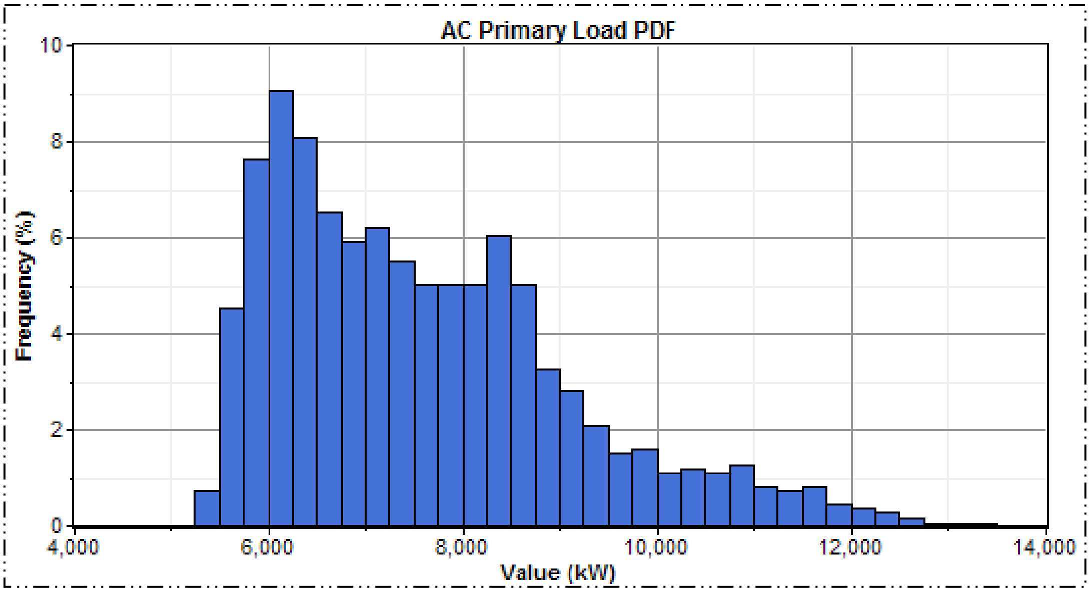

Figure 12. AC primary load frequency

Figure 13 shows the monthly electrical load averages for data gathered from June 1, 2008 to May 31, 2009.

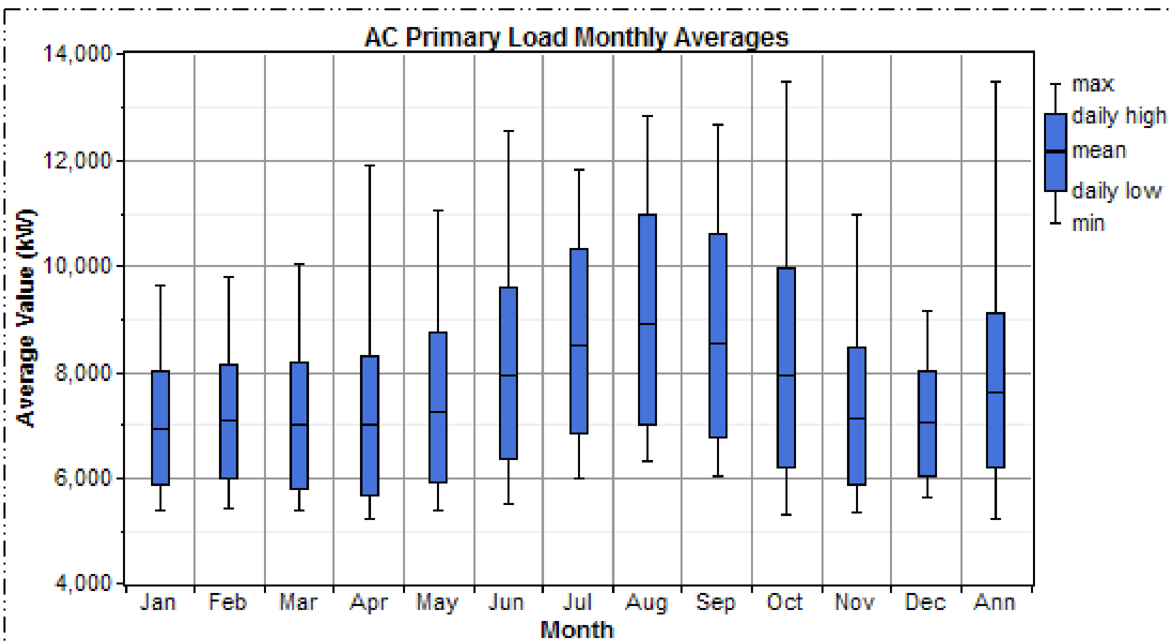

Figure 13. AC primary base-load monthly averages

The average daily profile peaks at approximately 12:00 and subsides around 18:00, as shown in Figure 14.

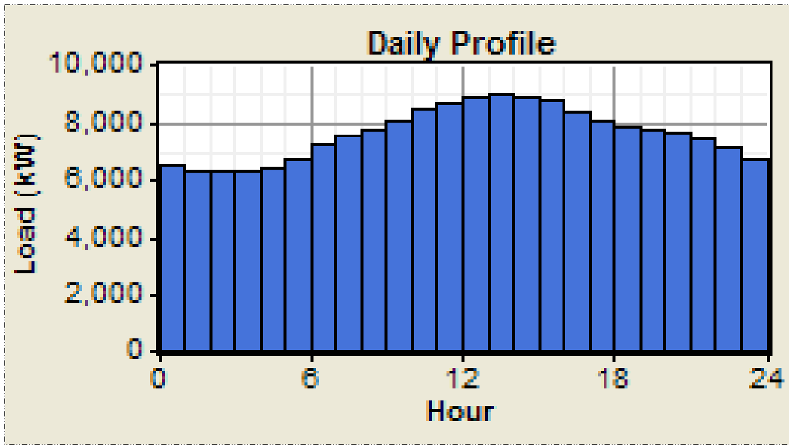

Figure 14. Average Daily Load Profile

2.4 Natural Gas Baseline

Natural gas consumption data were obtained from Miramar. Total Main Base consumption was given as 101,936 MBtu for FY 2007 and 101,923 MBtu for FY 2008. This does not include consumption for exempt facilities. An average of the two numbers was used to determine a natural gas baseline of 101,930. Natural gas consumption data were obtained for the Brig, Commissary, and Privatized Housing. Natural gas consumption was estimated for the Clinic. The estimated correction and load growth factor for natural gas was 3%. A summary of the natural gas consumption baseline is provided in Table 8.

Table 8. Natural Gas Baseline

Load Locations	Annual Consumption (MBtu)
Main Base	101,930
Clinic	973
Commissary	1,252
Brig	15,637
Privatized Housing	7,990
Total Other Loads	25,852
Grand Total	127,782
Correction and Load Growth (+3%)	3,833
Final Baseline	131,615

The California Energy Commission's *California Commercial End-Use Survey* was used to estimate the end use of Miramar's natural gas consumption.[12] The values used are for buildings in the Southern California Edison service territory; however, it was assumed that the energy use breakdown for these buildings is similar to energy use at Miramar. The survey gave values in terms of kBtu per square foot, per year of natural gas usage, by building type for heating, cooling, hot

[12] California Energy Commission. *California Commercial End-Use Survey*, CEC-400-2006-005, March 2006.

water, and cooking. This information was used with the building portfolio breakdown shown in Table 8.

Figure 15 shows the estimated end uses of natural gas at Miramar. Additional calculations are provided in Appendix D.

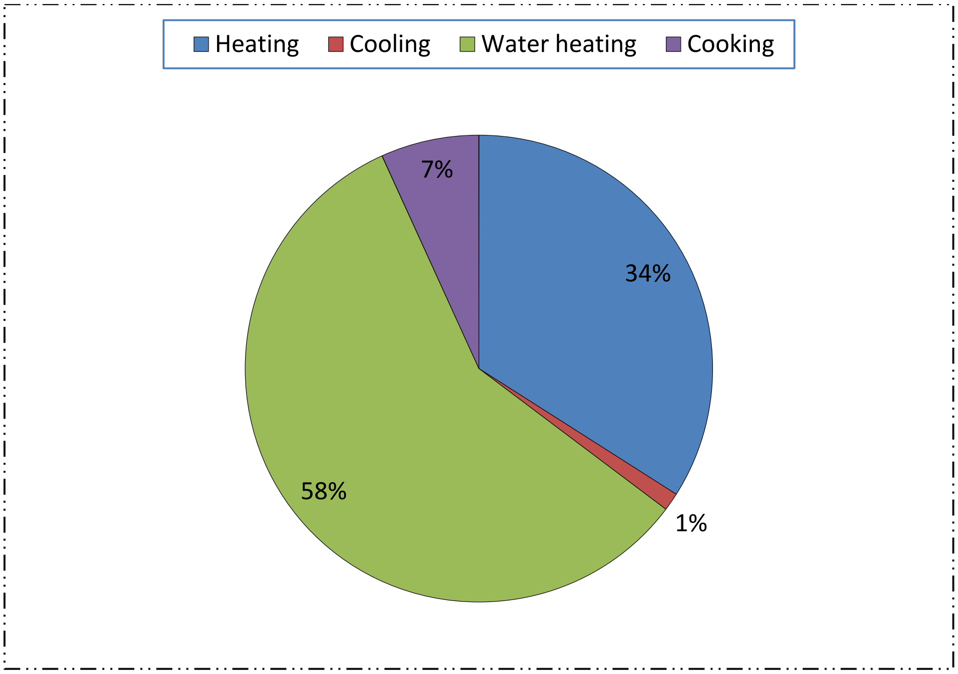

Figure 15. Estimated Miramar natural gas end use

2.5 Transportation Baseline

The NREL team visited MCAS Miramar in October, 2008 and was able to visit the fleet facility on base and speak with fleet personnel. Over several months, fleet data, including vehicle inventory and fuel use data, were provided to NREL. The fleet uses approximately 176,000 gallons of fuel annually. A summary of Miramar's vehicle fleet and associated fuel consumption is provided in Table 9.

Vehicle Fuel Type	Number of Vehicles	Fuel Used (gallons)
E85 Flex Fuel	102	
Gasoline	98	89,500
CNG Dedicated	39	45,000
CNG Bi -fuel	14	
Diesel	5	41,000**
HEV	4	
TOTAL	262*	175,500

Table 9. Vehicle Fleet Vehicle Type and Fuel Use

* Does not include about two dozen NEVs.
**Includes 31,000 gallons biodiesel.

When converting the fleet fuel use to source Btu for the energy baseline, it is important to account for the existing use of renewable fuel generated off-site in fleet vehicles. The biodiesel used is a blend of 20% biodiesel and 80% regular diesel. Currently about 925 MBtu of fuel are already coming from renewable sources. The baseline source Btu for the fleet from non-renewable sources is 23,400 MBtu.

2.6 Greenhouse Gas Baseline

Background. The EPA Climate Leader's GHG Inventory Guidance was used to establish a GHG emissions inventory for Miramar. The EPA guidance is based on an existing protocol developed by the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD). The WRI/WBCSD GHG Protocol was developed through a collaborative process involving representatives from industry, government, and nongovernmental organizations. The Climate Leaders GHG Inventory Guidance is a modification of the WRI/WBCSD GHG Protocol that more closely fits the needs of Climate Leaders.[13]

A GHG or CO_2 emissions inventory examines how an organization's activities contribute to climate change in terms of the GHG emissions it produces. The goal of the preliminary inventory is to help establish the boundaries for Miramar and identify initial GHG emissions and the associated carbon footprint. The baseline inventory will help to identify emissions reduction opportunities through the energy efficiency and onsite renewable energy projects recommended in this report.

GHG emissions are divided into three types, by goals and boundaries:

- **Scope 1—**Direct emissions: sources that the organization directly controls, including purchased natural gas, on-site fuel production, and fuel use of owned/leased vehicles.
- **Scope 2—**Indirect emissions: source of emissions normally generated off-site by the local utility company and thus, emissions that the reporting organization does not directly control. Included in Miramar's inventory are purchased electricity.
- **Scope 3—**Other Indirect emissions: optional sources, including products and services to market that are not controlled by Miramar. Indirect emissions include employee commuting, business travel, waste management, and processing and transportation of purchased materials.

Most public registries require reporting for Scope 1 and 2 emissions (Scope 3 emissions are usually optional).

Executive order, EO 13514[14] makes reducing GHG emissions a priority for Federal agencies. It directs agencies to establish a Strategic Sustainability Performance Plan with reductions of scope 1 and 2 GHG emissions (with reduction of scope 3 emissions as a separate goal) in absolute terms by fiscal 2020 relative to a FY 2008 baseline.

Analysis. The energy information gathered in this report was used to establish a preliminary GHG emissions inventory for 2008. The energy efficiency measures and renewable energy projects recommended were used as a preliminary template for establishing a GHG emissions baseline

[13] EPA Climate Leaders Greenhouse Gas Inventory Protocol. *Design Principles*. EPA430-K-05-005. May 2005. www.epa.gov/climateleaders/documents/resources/design-principles.pdf. Accessed April 2010.
[14] Federal Register. EO 13514, Federal Leadership in Environmental, Energy, and Economic Performance, Oct 8, 2009.

reduction. NREL did not have all the information required to establish a complete inventory for Miramar.

2.7 Baseline Greenhouse Gas Inventory

Boundaries. Determining the boundaries and scope of analysis is an important first step in designing an organization's carbon inventory. Many aspects of an organization's carbon footprint are difficult to quantify, and obtaining the data can be challenging. Emissions categories included in an inventory will also vary across organizations because those that are important in one organization may not significantly contribute to another's overall inventory. Miramar's carbon emissions inventory operational and scope boundaries were established using the NZEI boundaries and data. Guidance from the Recommended Public Sector GHG Accounting and Reporting Protocol[15] were also used.

Operational Boundaries. Miramar's GHG emissions inventory includes facilities that are within the gated boundaries. Some of facilities Miramar has direct operational control, and data available, while others are operated independently. The facilities that are considered in the GHG Inventory are: Main Base, Clinic, Commissary, Brig, and Privatized Housing. Utility data for the Main Base are controlled by NAVFAC, while the others are independently metered.

Scope Boundaries. The preliminary inventory for Miramar includes emissions from Scope 1 and Scope 2 only.

- Scope 1—Direct emissions
  - *On-site fuel combustion*. Natural gas is used to power boilers that heat some facilities and domestic hot water. Natural gas is accounted for in this emissions inventory.
  - *Fleet Vehicles*. Miramar uses its fleet of vehicles for grounds maintenance, security and other purposes. The majority of the vehicles are pickup trucks or sport utility vehicles. The emissions from gasoline, compressed natural gas, diesel and biodiesel used at Miramar are recorded in the preliminary inventory.

Data for the amount of diesel used for operation and maintenance (O&M) checks of backup generators are not available at the time of this study, but should be included in the final inventory. Emissions data from refrigerants are also not currently available for Miramar, but should be included in the future under
Scope 1.

- Scope 2—Indirect Emissions from Electricity Purchased
  - *Purchased Electricity*. Miramar purchases their electricity from NAVFAC. NAVFAC contracts with SDG&E to provide electricity to Miramar. Emission factors selected to calculate emissions associated with an organization's electricity consumption vary significantly. The most accurate calculation of impact is based on the fuel mix of the specific utility that supports the organization. Because site-specific emissions factors are often not available, state or regional factors are typically used. The GHG Protocol relies on data associated with the North American Electric Reliability Council (NERC) regions and EPA's

[15] LMI Research Institute. Recommended Public Sector GHG Accounting and Reporting Protocol, Report IR803R1, February 2009.

corresponding eGRID sub-regions (Appendix J). For Miramar, NREL used the emissions associated within the 2007 eGRID sub-regions for California (CAMX). The emissions factors used for the inventory are provided in Appendix J.

GHG Emissions. The GHG Emissions baseline calculated for 2008 shows that Miramar has an overall GHG emission of approximately 30,183 tCO_2. The primary source of the emissions (not including jet fuel) is from the purchase of electricity. Table 10 shows baseline GHG emissions:

Table 10. Baseline GHG Emissions

Stationary Combustion Sources	7,001.39	tCO_2e
Mobile Combustion Sources	1,229.87	tCO_2e
Refrigeration / AC Equip. Use (Not Available)	0.00	tCO_2e
Process / Fugitive (Not Available)	0.00	tCO_2e
SF6 Usage (Not Available)	0.00	tCO_2e
Total Direct Emissions	8,231.26	tCO_2e
Purchased and Used Electricity	21,951.60	tCO_2e
Total Indirect Emissions	21,951.60	tCO_2e
Total Direct and Indirect Emissions	30,182.86	tCO_2e
Total kWh of RECs	0.00	kWh
Total Reductions from RECs/Green Power	0.00	tCO_2e
Total GHG	30,182.86	tCO_2e

2.8 Utility Costs

The current cost of energy is one important factor in determining the economic viability of investments in energy efficiency or renewable energy. Miramar's energy is provided by SDG&E through NAVFAC. NAVFAC operates and maintains the base distribution network and provides utility service and billing. The average electrical and natural gas utility rates for the last six fiscal years along with projected rates for the next year are shown below in the figures below. The FY 2011 rates are NAVFAC estimates.

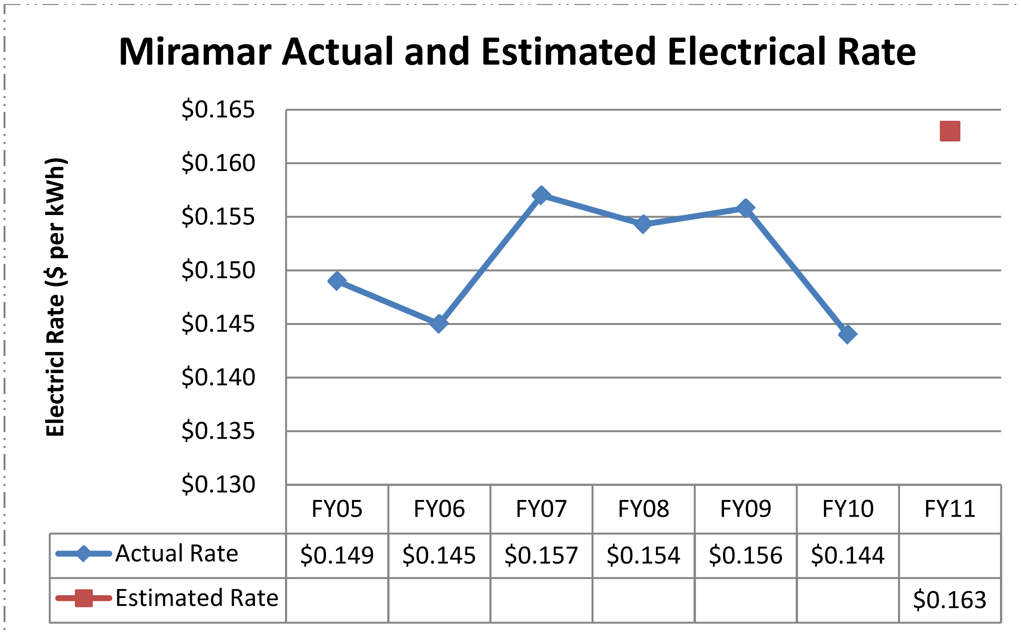

Figure 16. Average and projected energy prices

After the installation of renewable energy projects to achieve net zero electrical status, Miramar will likely still need to pay NAVFAC for the O&M of its distribution network. NREL was told that the current payments to NAVFAC are approximately $0.04 per kWh or $2,640,000 annually.

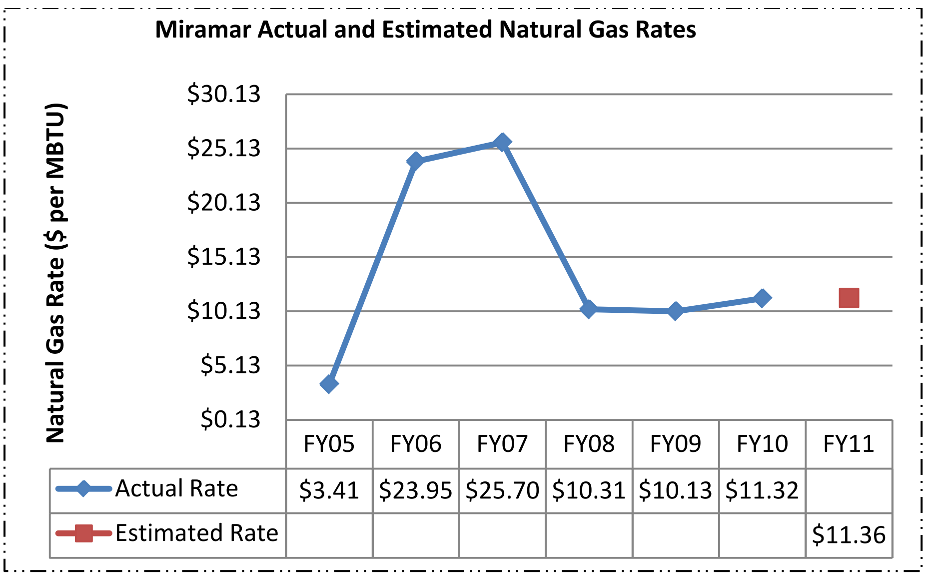

Figure 17. Miramar actual and estimated natural gas rates

Miramar reported to NREL that there was no additional cost built into their natural gas rate. It was unclear why the natural gas rates for the base had varied so dramatically over the last several years. Figure 18 shows the national average commercial natural gas rate and the average California commercial natural gas rate, as well as projected national average commercial rates for comparison purposes.

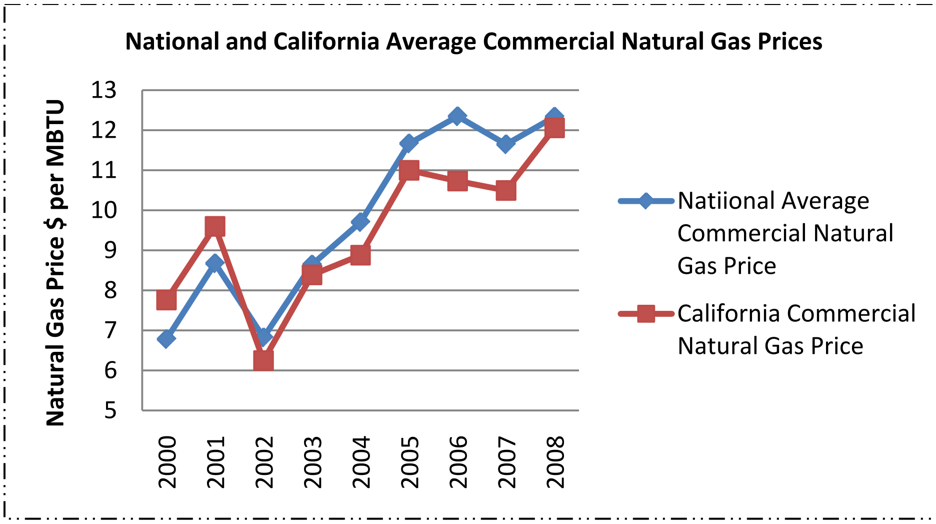

Figure 18. National and California average commercial natural gas prices

The projected national average natural gas price rates from the Energy Information Administration 2010 Energy Outlook were examined.[16] The projected rates for the next ten years are shown in Figure 19.

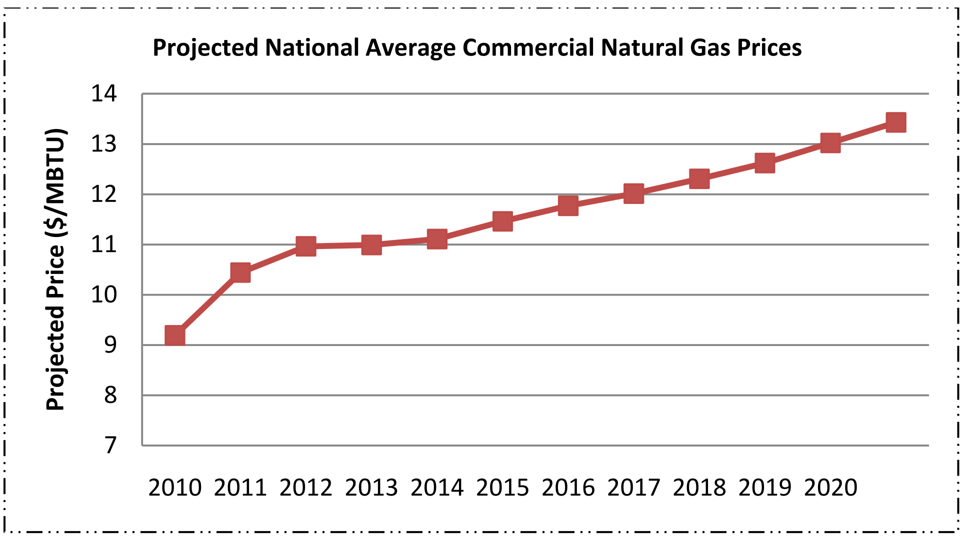

Figure 19. Projected national average commercial natural gas prices

[16] U.S. Energy Information Administration. Annual Energy Outlook 2010. Early Release. www.eia.doe.gov/oiaf/aeo/aeoref_tab.html.

3 Energy Project Screening

3.1 Overview

Energy efficiency opportunities, renewable resources, and renewable energy project potential at Miramar were screened to begin determining a net zero energy solution.

3.2 Energy Efficiency Potential

Buildings are responsible for the majority of the natural gas and electrical energy consumption at Miramar. While new buildings have the greatest potential to reach net zero energy status, building retrofits can also save a substantial amount of energy. A typical building can be retrofitted to reduce energy consumption by 30%. Building energy efficiency was assessed for Miramar facilities in order to determine the potential for additional energy efficiency investment.

Calculation of an EUI which measures site Btu per square foot for a building is a standard way to compare the efficiency of one building to another. The total square footage of the facilities on the Miramar base was given as 6.1 million ft^2. The total Btu consumed for the entire base using NREL's baseline figures was 334 billion site Btu. Using these two numbers, NREL calculated an EUI of approximately 55 kBtu/ ft^2 for Miramar. The energy manager at Miramar is required to submit an annual report to the DoD on the energy consumption in the Main Base facilities. The Main Base represents 82% of the total electrical load and 80% of the total natural gas load. However, certain Main Base buildings are exempt from this reporting requirement, for example the flight simulators are not included in this calculation. The total square footage that is included in this report is 5.6 million ft^2, thus approximately half a million $ft^2$of base facilities are not included in this reporting requirement. The reported EUI for the Main Base facilities was 49 kBtu/ ft^2 in 2008. This implies that the non exempt Main Base facilities are slightly more energy efficient than the rest of the base buildings. This is expected, as several high-energy-use facilities, such the flight simulators, are buildings exempt from this reporting requirement. However, using either number, Miramar's EUI is low when compared to other commercial buildings. The average EPA ENERGY STAR®-Certified commercial building has an EUI of 60 kBtu/ ft^2. The FY 2008 DoD average was 107 kBtu/ ft^2 [17] and the FY 2006 Federal government average was 113 kBtu/ ft^2. However, Miramar is located in a temperate climate zone that typically requires less energy use. Analysis of EPA ENERGY STAR-Certified commercial office buildings in the City of San Diego yielded detailed data for nine buildings with an average EUI of 54 kBtu/ ft^2.[18]

A 2007 NREL report addressed the net zero energy potential of standard new commercial building by climate zone.[19] Miramar is located in climate zone 3B, as shown in Appendix C. In this zone, a new commercial building could be expected to have an EUI of 46. A breakdown by climate sector is also provided in Appendix C. EUI's are typically low for most subsectors in climate zone 3B. However, the trend is clear, when comparing Miramar's existing EUI with a variety of other EUI's for similar buildings in the same climate zone, the base is already very energy efficient.

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[17] Office of the Deputy Under Secretary of Defense. Department of Defense Annual Energy Management Report, Fiscal Year 2008. US Department of Defense. January 2009. www.acq.osd.mil/ie/energy/library/DoDenergymgmtrpt08.pdf . Accessed April 2010.

[18] ENERGY STAR Web site: www.energystar.gov/index.cfm?fuseaction=labeled_buildings.locator. Accessed April 2010.

[19] Griffith, L.; Torcellini, P.; Judkoff, R. Assessment of Technical Potential for Achieving Net Zero-Energy Building in the Commercial Sector. NREL/TP-550-41957. Golden, CO: National Renewable Energy Laboratory, December, 2007.

The Main Base facilities at Miramar have undertaken several energy efficiency projects in the last few years and have reduced their energy consumption significantly. For example, daylighting and lighting controls were installed in some of the warehouses and hangars, an ESPC was executed, and significant water conservation measures have been enacted. In 2003, Miramar reported a consumption of 319,749 MBtu for 5,612,000 $ft^2$and an EUI of 57 kBtu/ ft^2. In 2008, the reported EUI of 49 kBtu/ ft^2 represented a 14% reduction from 2003. E.O. 13423 mandates a 3% annual energy efficiency improvement relative to the 2003 baseline between 2006 and 2015. This represents a 30% total reduction. To meet this mandate, Miramar will need to achieve a16% additional energy efficiency reduction and a EUI of 40 by 2015.

The building portfolio at Miramar is unique and does not simply match that of a commercial buildings or even all of the categories listed in Appendix C. The pie chart in Figure 20 shows the percentage of square footage at Miramar occupied by a particular building type. The detailed table is provided in Appendix C.

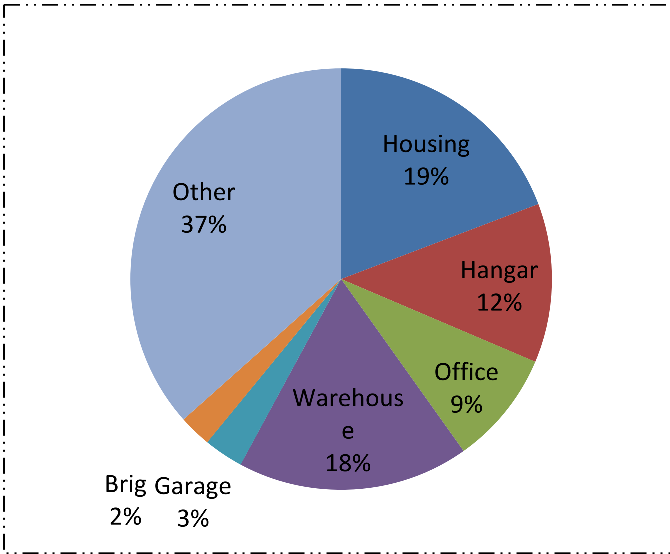

Figure 20. Miramar building portfolio breakdown

NREL was given building-level electrical and natural gas consumption data for 209 of the facilities at Miramar. These facilities represented 25% of the total number of facilities and 31% of the total base square footage. EUI values were calculated for these buildings, as detailed in Appendix C. Organizing the EUI numbers for Miramar into specific categories enables the energy efficiency potential to be analyzed more easily and makes savings opportunities become more apparent. For example, the office buildings at Miramar have an average EUI of 67, which is higher than the average ENERGY STAR-Certified building and indicates improvement potential. However, several of the facilities at Miramar are supplied by common natural gas meters. Thus, the facility where the natural gas meter is located may appear to have a EUI higher than its actual value because the natural gas usage represents several buildings.

Despite the base's already low EUI and past energy efficiency investments, there is potential for the buildings at Miramar to become even more energy efficient in a cost effective manner.

3.3 Renewable Energy Resource Assessment

NREL began its analysis of the renewable energy generation potential of Miramar by examining the high-level resource potential. The analysis includes Miramar-specific solar and wind resource maps, as well as national biomass and geothermal resource maps. Appendix G shows the renewable energy resource maps provided by the NREL GIS group. Overall, the maps indicate good solar resource potential, moderate geothermal and biomass potential, and poor wind potential.

Solar. The solar resource map for PV shows that the entire Miramar site falls in the 6.0 to 6.5 kWh/m^2/day category, which indicates a high resource capability. The direct normal solar resource is also significant, with the east half of Miramar having resource in the 5.0 to 5.5 kWh/m^2/day category and the west half in the higher category of 5.5 to 6.0 kWh/m^2/day.

Wind. The wind resource for all of Miramar is in the Class 1 category, which is very low.

Biomass. The largest potential feedstock for Miramar would be urban wood waste, at 278,928 tons per year and municipal solid waste (MSW) of 1,100,000 tons per year.

Geothermal/Ground Source Heat Pump. Information on the direct geothermal resource at Miramar was not available. The national version of the geothermal resource map indicates moderate geothermal project potential at the site. Southern California has several geothermal projects, but the industry is not fully developed and project costs would likely be higher than average.

3.4 Renewable Energy Optimization

In addition to the basic resource assessment, the NREL team conducted an initial assessment of the renewable energy opportunities for Miramar based on high-level energy data provided by Miramar and the Navy staff, using resource potential and NREL's REO software tool. The initial screening evaluated the following technologies:

- PV
- Wind
- Biomass gasifier/cogen
- Daylighting
- Solar thermal or CSP
- Solar hot water
- Solar vent preheating
- Anaerobic digesters.

The REO analysis determined the basic technical and economical feasibility of the use of these technologies at Miramar. Several separate REO scenarios were analyzed using the NREL baseline consumption data of 66,543,615 kWh of electricity, 131,615 MBtu of natural gas, and a total installation building size of 6,109,743 ft^2.

When the REO was allowed to optimize a net zero energy solution for Miramar using all of the technologies above, the software suggested using a large amount of wind power, despite poor resource availability. This was due largely to the generous incentives available for wind power. However, Miramar was concerned about the impact of large wind turbines on the flight missions of the base due to potential radar reflectivity. As a result, wind turbines were eliminated from further analysis for the net zero energy solution. Additionally, REO suggested using solar vent preheating technology at Miramar. This technology was also eliminated from further consideration due to base concerns. Finally, REO found that an anaerobic digester would likely not be cost effective and the base surrounding area did not have the required waste resource, so this technology was eliminated from further analysis.

To achieve net zero energy without using wind or solar vent preheat, REO suggested using a combination of daylighting, PV, solar thermal, and biomass renewable energy technologies. Additional details on the REO analysis are provided in Appendix B.

Miramar will likely sign a PPA for 25,000 MWh of electricity to be generated annually from landfill gas. This scenario was also included in several REO analysis runs. The basic results were similar, but the recommended technology sizes were changed. Additional details on the REO analysis are provided in Appendix B. Through discussions with the base, it was determined that Miramar does not have the available area for the relatively large solar thermal project suggested by REO at this time, but the base landfill area may be available in the future. Thus, the most likely technology solution was a combination of landfill gas electric power, solar hot water, daylighting, PV, and biomass projects. This REO solution is presented below.

To achieve net zero energy solution that includes the landfill gas PPA and excludes the use of wind, solar thermal, or solar vent preheating technologies, REO suggested the following technology sizes:

- 115,967 ft^2 solar water heating
- 8.2% non-office daylighting (skylight to floor area in square feet)
- 5.6% office daylighting (skylight to floor area in square feet)
- 23,742 kW of PV
- 20.3 MBtu/hr biomass gasifier with a 2204 kW co-gen system.

In summary, several technologies were eliminated from further analysis and a proposed landfill gas PPA was included in the analysis based on the resource assessment, REO screen, and discussions with Miramar. Technologies eliminated from additional analysis are wind, solar vent preheat, and anaerobic digestion. Technologies to be analyzed further are PV, solar thermal, ground source heat pumps, solar hot water, daylighting, and biomass.

4 Energy Efficiency Project Assessment and Recommendations

4.1 Overview

Before conducting further analysis of the renewable energy generation technologies, NREL evaluated Miramar's energy efficiency improvement potential. Energy efficiency and conservation analysis were conducted first as they will reduce the electrical and natural gas loads at the base and the sizes of the renewable energy systems required. Additionally, energy efficiency is typically the most cost-effective energy project investment.

Miramar has several projects already planned to increase the efficiency of its building portfolio. Analysis was conducted on the planned energy efficiency projects on the base as well as further energy efficiency improvement opportunities.

The estimated savings potential is shown below.

- Total electrical reduction = 10,676 MWh or 16.0% electrical load reduction
- Total natural gas reduction = 14,104 Site MBtu or 10.7% natural gas load reduction
- Total Btu reduction = 13.3% reduction.

4.2 Planned Efficiency Projects

Boiler Replacement and Solar Thermal Hot Water. Miramar was recently awarded American Recovery and Reinvestment Act (ARRA) funding for a proposal to replace boilers and add solar hot water systems to buildings in base areas 6, 7, and 8.[20] Solar hot water systems will be added to buildings that have large hot water loads and existing storage tanks. These include six buildings in Area 7, one in Area 8, and one in area 9. The remaining buildings without storage tanks and a large load will likely receive tankless water heaters. The total projected savings are 2,950 MBtu of natural gas, which represents 2% of the total baseline natural gas consumption of Miramar. Additionally, the project is projected to save 520 MWh of electricity which represents about 0.8% of the total consumption. About 15% of the total natural gas savings are estimated to be a result of the proposed solar hot water systems and 85% are estimated to be a result of energy efficiency improvements.[21] The main driver of this project was not to save energy, but to replace outdated boilers nearing the end of their useful life and reduce operations and maintenance costs. Miramar estimated it is currently spending $600,000 per year to maintain these boilers.

Energy Saving Performance Contract Proposal. An ESPC proposal was prepared for Miramar in August of 2008. The proposal contained a variety of energy savings opportunities. Miramar was unable to execute the contract, but remains interested in energy efficiency improvements and plans to solicit a new ESPC proposal in the near future.

4.3 Assessment of Additional Energy Efficiency Projects.

It was beyond the scope of this project to conduct detailed energy audits of the approximately 800 installation facilities at Miramar. However, through discussion with base personnel, analysis of the previous efficiency work, and a visit to several of the facilities on base, the savings potential for energy efficiency investment at Miramar was estimated.

[20] The Installation at Miramar is broken down into nine base areas. Each base area represents a specific location and group of facilities on the installation.

[21] Base Energy Manager Randy Monahan.

Total electrical reduction = 10,676 MWh or 16.0% electrical load reduction

Total natural gas reduction = 14,104 Site MBtu or 10.7% natural gas load reduction

Total Btu reduction = 13.3% reduction

The savings estimates are shown below by facility category and energy conservation measure:

***Main Base*. (**16% site Btu reduction needed to meet Federal mandates)

- Electrical reduction = 9228 MWh or 14% of total baseline electrical load
  - ECM estimated savings = 8721 MWh
    - 4989 MWh controls and retro-commissioning
    - 557 MWh plug loads
    - 1428 MWh exterior lighting
    - 200 MWh chillers
    - 1099 MWh daylighting in warehouses
    - 430 MWh interior lighting savings in offices
    - 5 MWh refrigerator replacement
    - 520 MWh planned ARRA funded boiler replacement project
  - ECMs in which savings were not estimated
    - Replacement of rooftop package unit air conditioners with more efficient models
- Natural gas reduction = 11,844 MBtu or 9.0% of baseline natural gas load
  - ECM estimated savings = 11,844 MBtu
    - 2,950 MBtu planned ARRA funded boiler replacement project
    - 8,894 MBtu controls
- ECMs in which savings were not estimated
    - Reduction from reduced water use
    - Reduction from right sizing of hot water systems in hangars and warehouses

***Commissary and Exchange*.**

- Electrical reduction
  - ECM estimated savings = 921 MWh
    - 921 MWh from lighting and refrigeration
- Natural gas reduction
  - ECM estimated savings = 63 MBtu
    - 63 MBtu from use of refrigeration waste heat

***Privatized Housing*.**

- Electrical reduction = 13% of housing load or 527 MWh
  - ECM estimated savings = 527 MWh or 13% of housing load
    - 139 MWh programmable thermostat
    - 199 MWh interior lighting
    - 189 MWh installation of more efficient ENERGY STAR appliances
      - Assume ENERGY STAR refrigerators use 20% less energy
      - Assume ENERGY STAR washing machines use 33% less energy
      - Assume ENERGY STAR dish washers use 31% less energy
      - ECMs where savings were not estimated
        - ✓ Installation of more efficient air conditioners up to 75% savings
    - Natural Gas reduction = 27% of housing load or 2,197 MBtu
      - 1185 MBtu programmable thermostat

- 1,012 MBtu low flow showers and faucets
  - ✓ Assume low flow faucets use 18% less energy
    Assume low flow showers use 20% less energy

4.4 Main Base Facilities

The Main Base facilities represent the vast majority of the energy use at Miramar: 82% of the total electrical load and 80% of the total natural gas load. Numerous recommendations were developed to reduce energy usage in these facilities. Energy conservation measures that apply across all building categories are listed first and then several specific building categories where walkthroughs were conducted are examined in further detail.

Base-Wide Conservation Measures

HVAC

Chillers. Many of the current facilities at Miramar are operating moderately efficient chillers. It is recommended that they install more efficient chillers. Buildings 7490, 7494, 7550, 7690, 8380, 8477, 8671, 9170, and 9211 were previously analyzed for potential chiller retrofits. These buildings represent a total of 319,521 ft^2. The estimated savings from these upgrades would be approximately 200,000 kWh. It is recommended that additional facilities be analyzed for chiller upgrades as these are likely to have significant savings potential as well.

Air Handling Units. The majority of the air handling units (AHU) at Miramar are already variable air volume (VAV) systems. However, upgrading the remaining units to VAV systems would save energy by reducing the amount of air that needs to be heated or cooled. It is recommended that the AHU across the base be evaluated and appropriate units to upgraded to VAV models.

Boilers. The efficiency of the boilers at Miramar varies; some of the boilers are very efficient while others could be replaced to save a substantial amount of energy. It is recommended that the boilers not replaced in the ARRA-funded retrofit be examined. Boilers with efficiencies less than 85% should be examined for replacement potential with high efficiency boilers that can achieve up to 95% efficiency.

ENERGY STAR Refrigerators

Replacing refrigerators on the Main Base with ENERGY STAR models could provide energy savings. Small refrigerators are located in each of the barracks housing units and it was assumed that the office buildings contained them as well. Savings would vary by the model being replaced, but would be 50 to 200 kWh per year. Assuming 50 refrigerators are replaced and the energy savings are 100 kWh per year for each, the total energy savings would be approximately 5,000 kWh per year or 5 MWh.

Controls

During the site visit, many of the building control systems at Miramar were found not to be operating optimally. For example, several buildings were being heated during a 70°F day and building exterior lights were turned on during the day. Base personnel stated the need for numerous control system upgrades and for building retro-commissioning. It was estimated that all of the buildings 10,000 ft^2 and larger contained control systems. The total area of these buildings is about 4.2 million ft^2 or 69% of the total base facility area. It was assumed these buildings accounted for approximately 69% of the energy use on the base for a total electrical load of 45,000 MWh and 90,000 MBtu. A subset of these buildings was previously analyzed for control system improvement potential. These buildings were all managed by direct digital controls (DDC) control systems. The majority of these buildings could benefit from control upgrades and retro-commissioning. Some of the potential control upgrades include:

- Boiler optimization
- Chiller optimization (chilled water reset and sequencing)
- Cooling tower optimization (recommendation to only run as many fans as needed to meet condenser water set point)
- DDC controls
- Electric demand limiting
- Static pressure set-point adjustment
- Mixed air dampers – for economizer
- Night setback
- Night purge (building precooling at night)
- Occupancy sensor control
- Lighting scheduling (centralized lighting control)
- Optimal start/stop HVAC systems
- Outdoor air reduction
- Supply air reset
- VAV and variable pumping

Savings ratios for the previously analyzed buildings were calculated on a per ft^2 basis and this ratio was applied to the larger set of buildings. However, the natural gas savings per ft^2 was reduced by 1/3 to account for the more efficient boilers and solar hot water systems already being installed. This reduction was necessary because the new systems will be more efficient and use less energy than the systems that were in place when the previous analysis was conducted. Additionally, it was assumed that only 75% of these estimated savings could be realized. The savings calculations are shown in Table 11.

Table 11. Estimated Savings from Control Upgrades and Retro-commissioning

Controls ECM	
ft^2 Analyzed	405,176
Elec Savings (kWh)	638,047
Gas Savings (MBtu)	1,723
Elec Savings Per ft^2 Analyzed	1.575
Gas Savings Per ft^2	0.0028
Potential Building Type	10,000 ft^2 and up
Total Potential ft^2	4,224,071
Elec Potential Savings (kWh)	6,651,809
Gas Potential Savings (MBtu)	11,858
% Captured	75%
Est. Elec. Savings (kWh)	4,988,857
Est. Gas Savings (MBtu)	8,894

In this scenario, the total estimated savings are 4,989 MWh and 8,894 MBtu. Comparing these savings to the total estimated load for these buildings shows a savings of 11% of the electrical load and 10% of the natural gas load. The American Council for an Energy Efficient Economy (ACEEE) estimated that retro-commissioning could save 5% to 20% of building energy consumption.[22] Thus, savings estimates that include both control system upgrades and retro-commissioning seem reasonable. Building commissioning should be viewed as a continuous process and revisited on a regular basis to ensure that the buildings are operating optimally as their use, set points, and other requirements may change over time.

Plug Loads

NREL used its screening tools to estimate the potential for plug load reduction at Miramar. NREL examined several vending machines on base. None of the machines contained vending misers, but some had been delamped. Additionally, base personnel stated that no computer power management programs were used. Savings were estimated for installing 50 vending machine misers, delamping 25 vending machines, using power management on software on 1,500 computers (200 laptops, 600 desktops with CRT monitors, and 600 desktops with LCD monitors). Table 12 shows the projected savings from these measures. The majority of the savings are provided by the computer management program which has a very attractive 0.86 year payback. The total savings are 557 MWh per year.

[22] Thorne, J.; Nadel, S. Retrocommissioning: Program Strategies to Capture Energy Savings in Existing Buildings. A035. Washington, DC: American Council for an Energy Efficient Economy, June 2003. http://old.aceee.org/pubs/a035.htm. Accessed April 2010.

Table 12. Projected Savings from Plug Loads

Plug Load ECM#	Energy Conservation Measure	Annual Energy Savings (kWh/yr)	Annual Cost Savings ($)	Annual O&M Costs ($)	Implementation Costs ($)	Simple Payback Period (yrs)	Discounted Payback Period (yrs)	Net Present Value (NPV)	Savings to Invest. Ratio (SIR)
1.1	Install Vending Machine Misers	70,080	$11,213	$0	$17,000	1.52	1.61	$237,500	14.97
1.2	De-Lamp Vending Machine Advertising Lighting	10,950	$1,752	$0	3,750	2.14	2.29	$36,016	10.60
1.3	Activate Computer Power Management	475,534	$76,085	$4,500	61,825	0.86	0.91	$1,550,060	26.07
Totals		*556,564*	*$89,050*	*$4,500*	*$82,575*	*0.98*	*-*	*$1,823,576*	*23.08*

Exterior Lighting

Exterior lighting is estimated to represent approximately 8% of Miramar's electrical load. The base is planning to replace 600 street lights with solar powered models. The base will be replacing 450W lights with lights that use solar power and batteries to fully power themselves. Assuming that these lights operate every day for an average of 11 hours, the energy savings would be 1,264 MWh per year. This represents 1.9% of the total base electrical load.

Additionally, upgrades were recommended for exterior wall pack lighting fixtures. Replacing the 500 existing 175W wall pack fixtures with 93W compact fluorescent lighting (CFL) wallpack fixtures would save approximately 164 MWh of electrical energy per year.

It is recommended that all of the exterior lights on the buildings at Miramar be placed on automatic timers or connected to photoelectric sensors to ensure that they do not operate during the daytime hours.

Heat Pumps

Air-source. Air-source heat pumps provide the opportunity to reduce base energy consumption. Air-source heat pumps are electric pumps that use the temperature difference between outside and inside air to heat a building. The pumps are commonly used in moderate climates such as San Diego and would be a good fit for Miramar. The use of air-source heat pumps provides the opportunity to switch from natural gas-fired heating systems to electrically powered heating systems. It was estimated that approximately 34% of the Miramar's natural gas consumption was used for building heating. If the base switched to air-source heat pumps, the energy used for heating would be reduced by 66% due to the greater efficiency of air-source heat pumps relative to natural gas systems. The total heating load is estimated at 45,000 MBtu of natural gas. Using air-source heat pumps would reduce this value to 15,000 MBtu of electricity. If Miramar were to use renewable electric energy to power the air-source heat pumps, the base would not only improve on the goal of becoming a NZEI, but would have increased energy security because the energy used for heating would be generated and consumed onsite. Assuming an electricity price of $0.16 per kWh, the use of air-source heat pump would be cost effective at a natural gas energy price of $16.21 per MBtu. The price paid per MBtu of natural gas by Miramar has historically varied between $10 and $25 per MBtu. Due to this price variability, it is difficult to determine the cost effectiveness of air-source heat pumps at Miramar. Since natural gas prices are so volatile at the base and are currently at historically low national prices, NREL does not recommend switching to air-source heat pumps at this time.

Recommended Action*:* None

Ground-source. GIS map analysis showed moderate geothermal resource potential at Miramar. NREL examined the possibility of using GSHPs to provide both cooling and heating. GSHPs are electrically powered and use the constant temperature of the earth to provide both a heat sink and source. Thus, GSHP can be used to provide both energy-efficient heating and cooling.

In 2007, the DoD conducted a study of the potential for GSHPs at various military installations.[23] Four GSHP projects were found in the same climate zone as Miramar. However, economic details of these projects were not available. The report analyzed the locations of installed GSHPs at various DoD facilities and found that 60% of the total projects and 90% of the installed capacity were for housing units. A substantial portion of the housing units at Miramar have been privatized and installation of GSHPs would require coordination with private contractors responsible for housing at Miramar. The DoD also conducted a payback analysis for GSHPs in various cities. For San Diego, analysis was conducted on various system configurations (vertical bore and hybrid GSHP), building types (classroom, administration, and barracks), and soil types (heavy sat, damp heavy, damp light). In each scenario, the payback for a system in the San Diego area was greater than 25 years, regardless of configuration. The analysis did not examine the economics of open-loop systems tied to a ground-water or reclaimed water source. While San Diego does not have large amounts of ground water available in most areas, a GSHP system could potentially be used at Miramar along with the purple-water system. (Miramar has an existing purple water system that uses reclaimed water for irrigation) In this scenario, the costs of system installation would be reduced. However, an economic analysis would be needed to determine the cost savings and impact of switching from natural gas heating to electrically powered GSHPs.

Recommended Action*:* Further analysis of the installation of GSHP tied to the purple-water system at Miramar.

Hybrid Evaporative Cooling Roof Top Units

Current Condition*:* Many of the smaller buildings at Miramar are currently conditioned by standard roof top units. These units use a direct expansion (DX) refrigeration cycle to cool the building.

Recommended Action*:* Replace the standard DX roof-top units with hybrid indirect evaporative-cooling units. These units operate on a system that uses both evaporative cooling and the traditional refrigeration cycle. Indirect evaporative cooling cools the space without adding humidity to the conditioned air. While evaporative cooling works best in arid climates and has traditionally had limited applications, the development of a hybrid system has greatly expanded the application and

[23] Deputy Under Secretary of Defense. *Report to Congress: Ground Source Heat Pumps at Department of Defense Facilities*. Washington, DC: Office of the Secretary of Defense, January 2007. www.acq.osd.mil/ie/energy/library/GSHP-Report_JAN242007.pdf. Accessed April 2010.

climate range for which it is practical. Climate data show that Miramar is a suitable location for hybrid evaporative cooling in its small commercial buildings. Tests performed at NREL demonstrate the potential for 75% savings in cooling energy when using this type of unit instead of a standard DX cooler. The analysis for this ECM was performed based on products and technologies developed by the Coolerado Corporation.

Miramar has many office buildings and housing units for which this recommendation would be appropriate. Several evaporative cooling units could be combined to serve large buildings where a single unit cannot cool the entire load. These units work best in small to medium-sized buildings and it is recommended that the larger facilities continue to use centralized chillers. Cooling is estimated to account for 15% to 20% of the electrical load in conditioned buildings at Miramar and savings of 75% of this energy could be significant for the base.

4.5 Specific Main Base Facilities

Offices. There are 39 buildings categorized as office buildings on the Main Base at Miramar. They comprise an area of 534,000 ft^2. The average building size is 13,691 ft^2. Offices comprise 8.74% of the total installation building square footage. Offices at Miramar were found to have an EUI of 67. Analysis of detailed data for EPA ENERGY STAR-certified office buildings in the City of San Diego yielded nine buildings with an average EUI of 54 kBtu/ ft^2.[24] Miramar could achieve EPA ENERGY STAR certification for its office buildings with approximately a 20% EUI reduction. NREL conducted a walkthrough of office building 8380 to assess energy efficiency improvement potential. The load profile for building 8380 is shown in Figure 21.

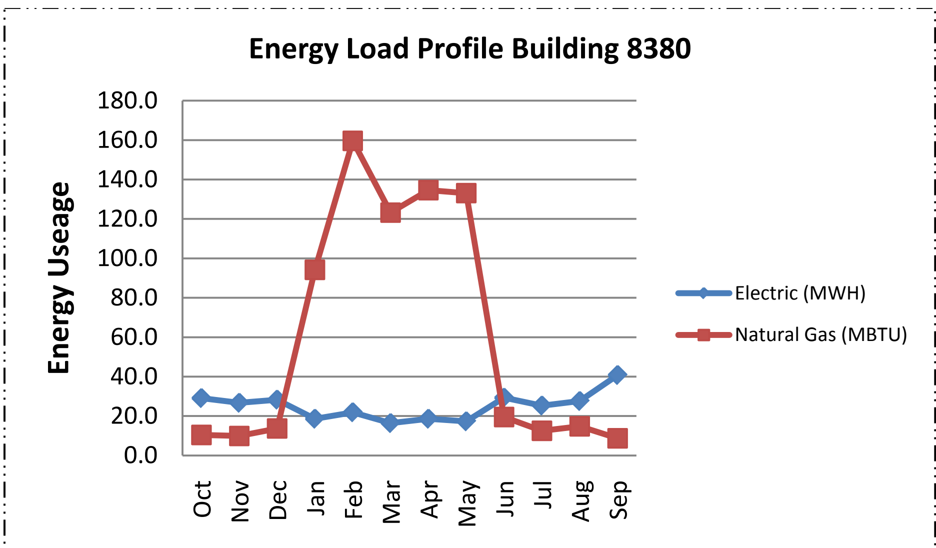

Figure 21. Energy load profile building 8380

Potential Improvements and Savings Estimates

Install Occupancy Sensors in the Office Spaces, Work Spaces, and Bathrooms

Current Condition: There are few working occupancy sensors currently installed in the office buildings at Miramar. Occupancy sensors can save considerable energy by turning off the lights when spaces are unoccupied. Large cubicle workstation areas, conference rooms, private offices, and restrooms comprise the majority of the lighting load in a typical office building. It is likely that

[24] ENERGY STAR Web site: www.energystar.gov/index.cfm?fuseaction=labeled_buildings.locator. Accessed April 2010.

many of these areas are intermittently occupied or vacant throughout the course of the day, and installing occupancy sensors could achieve energy savings.

Figure 22. Typical small-office wall switch sensor application and coverage

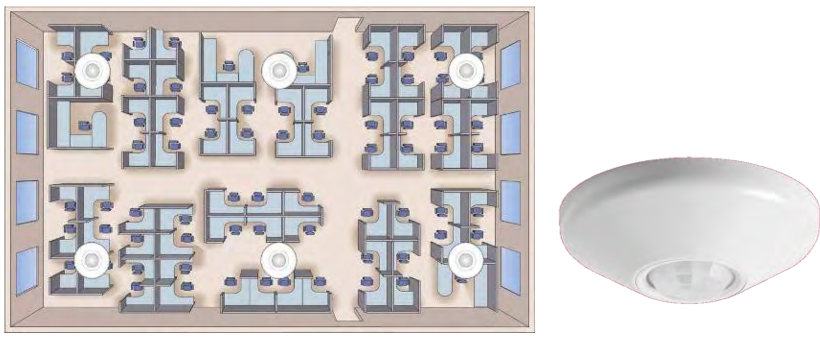

Figure 23. Typical open-space ceiling-mounted sensor application and coverage

Recommended Action: Install ceiling-mounted infrared occupancy sensors to automatically activate and deactivate space-lighting circuits based on occupancy. This measure will not reduce peak demand, but will reduce annual energy consumption.

Estimated Energy Savings of 149,112 kWh/yr.

Assumptions:

- The calculation assumes an average lighting power density of 1.3W/ ft^2 for 39 buildings.
- 30% of the total electric use for the buildings was assumed to go to lighting.
- 80% of the lighting was assumed to be appropriate for occupancy sensor control.
- 10% lighting energy savings from occupancy sensors were assumed.[25]

Replace the 32 W Linear Fluorescent T-8 Lamps with 25 W T-8 lamps

Current Condition*:* The majority of lighting in the office buildings at Miramar is provided by standard 32 W T-8 linear fluorescent lamps. The NREL audit team took light level measurements in Office Building #8380 and found that most of the spaces in the building were over-lit based on the lighting standards developed by the Illumination Engineering Society of North America (IESNA).

Recommended Action: Replace the existing with 32 W lamps with 25 W T-8 lamps. While this is likely a simple measure to implement, the current ballasts should be checked to be certain that they are compatible with 25W lamps. If they are not, new ballast should be considered. This measure can

[25] American Society of Heating, Refrigerating, and Air Conditioning Engineers (ASHRAE) Standard 90.1

be implemented at once or phased in with the established cycle of lamp and ballast replacements. This measure will reduce lighting levels in the building by 15% to 25%, bringing Miramar closer to the IESNA recommended standards.

Estimated Energy Savings of 305,796 kWh/yr.

Assumptions:

- The calculation assumes an average lighting power density of 1.3 W/ ft^2 for 39 buildings.
- 30% of the total electric use for the buildings is assumed to go to lighting.
- The savings calculations for these lighting control measures are provided in Appendix E.

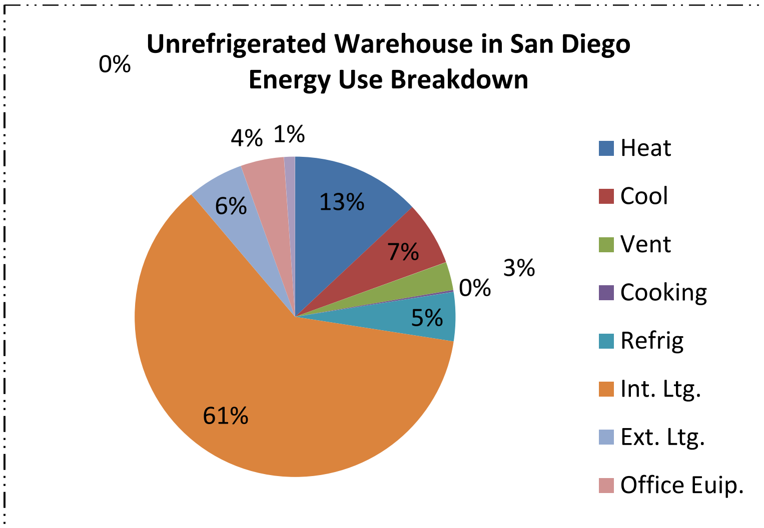

Figure 24. Unrefrigerated warehouse in San Diego energy use breakdown

Warehouses. Warehouses comprise 17.6% of the total facility area at Miramar. The base has 50 buildings categorized as warehouses with a total area of 1,084,432 ft^2. The average size is 21,689 ft^2. Many of the warehouses also have small amounts of office space in them. The average EUI for a warehouse at Miramar was 19. The national average EUI of a warehouse in the 2003 Commercial Building Energy Survey was 45. However, 43% of the load in a standard warehouse is from heating and 2.9% is from cooling. The warehouses at Miramar are largely unconditioned, which likely accounts for this large difference. The estimated end use energy breakdown of an unrefrigerated warehouse in San Diego is shown in Figure 24.

NREL conducted walkthroughs of warehouses 6001 and 7209 to examine energy efficiency potential. The load profiles for these buildings are shown in the following figures.

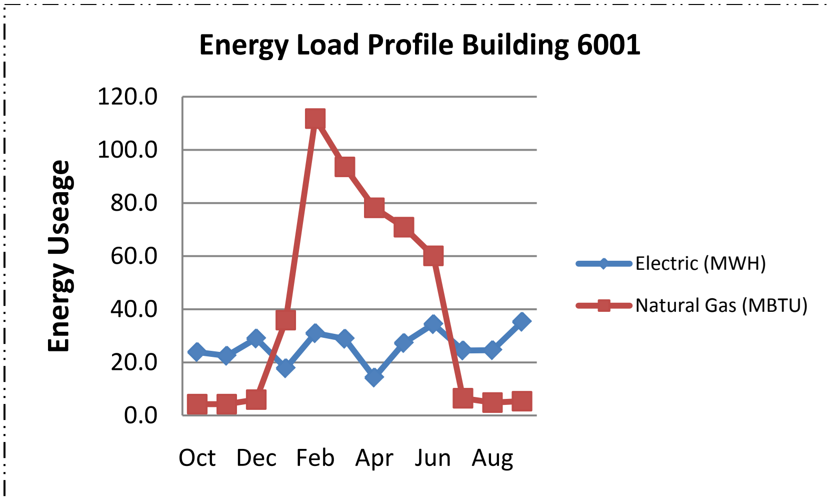

Figure 25. Energy load profile building 6001

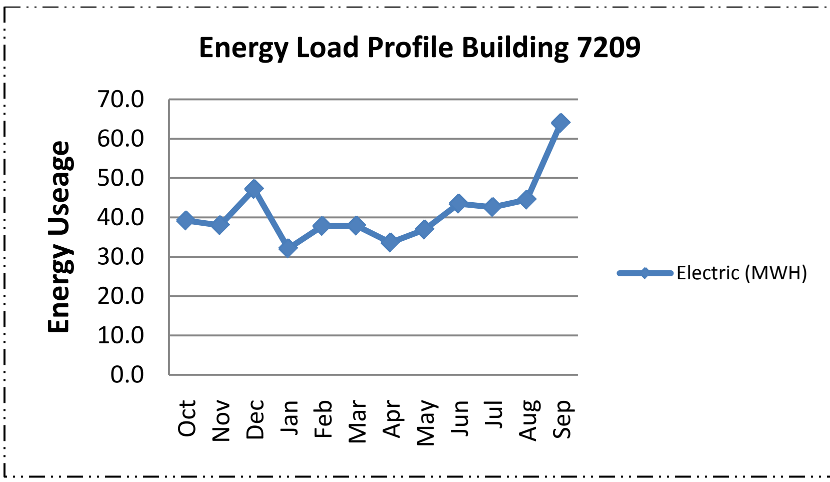

Figure 26. Energy load profile building 7209
(natural gas load data were not available for building 7209)

***Potential Improvement and Savings Estimate**:* Approximately 33% of the warehouses have daylighting systems installed. Recommend expanding daylighting to more facilities. If daylighting was installed on the remaining warehouses, the total building area would be 715,725 ft^2. The lighting load for a warehouse is estimated to be 13.1 kBtu per ft^2 , or 3.84 kWh per ft^2. The total lighting load for the remaining warehouse is estimated at 2,748 MWh. Daylighting systems could reduce this load by 20% to 60%. Assuming a 40% reduction the savings would be 1,099 MWh. This would represent a reduction of 1.7% of total base electrical load.

***Findings without recommended improvements**:* All warehouses use T-8 lighting with automatic controls. The warehouses are largely unconditioned. Several of the warehouses appeared to have oversized and outdated boilers. These boilers are scheduled for resizing and replacement with more efficient models under the ARRA-funded boiler replacement project.

Hangars. Hangars comprise 12.2% of the total facility area at Miramar. There are 12 buildings categorized as hangars totaling 744,878 ft^2 with an average size of 62,073 ft^2. Several of the hangars also contain office space of about 15% of the total square footage. Excluding Building 7125, which is not a traditional hangar, the average EUI for the hangars at Miramar is 55. .

Table 13 shows hangar details.

Table 13. Hangar Consumption Breakdown

Building Number	NAME	Area (ft^2)	TYPE	Data Electric (MW)	Data Nat Gas (MBtu)	EUI (kBtu/ ft^2)
7125	Avionics Tact Van Pads	5,201	Hangar	995	1391	920
7550	Administration Bldg..	53,402	Hangar	1113	794	86
9010T	Maint. Power Line VMFAT	2,245	Hangar	0	0	0
9170	KC-130 Hangar 0	53,394	Hangar	615	476	48
9215	Aircraft Maint Hangar	127,904	Hangar	1553	1308	52
9223	Aircraft Line Operations Bldg.	1,357	Hangar	2	0	4
9277	Aircraft Maint Hangar	133,694	Hangar	480	2159	28
9470	Aircraft Maint Hangar	127,829	Hangar	712	0	19
9500	Aircraft Maint Hangar	84,101	Hangar	899	1903	59
9570	Aircraft Maint Hangar	55,287	Hangar	745	0	46
9645	X-RAY Operator Enclosure	260	Hangar	0	0	0
9670	Hangar #6	100,203	Hangar	1312	0	45
Total		**744,878**		**8,425**	**8,030**	

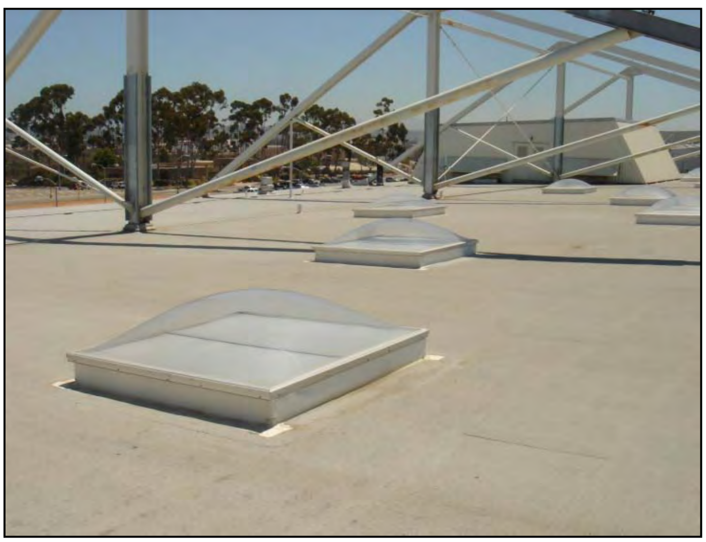

Figure 27. Daylighting system on hangar (Credit: NREL)

NREL conducted a walkthrough of Hangar 6 (Building 9670). Many of the hangars already contain updated lighting systems with lighting controls and daylighting. Figure 27 shows the daylighting on the roof of Hangar 6.

The load profile for Hangar 6 was not available. The load profile of Hangar 2 (Building 9215) is shown in Figure 28.

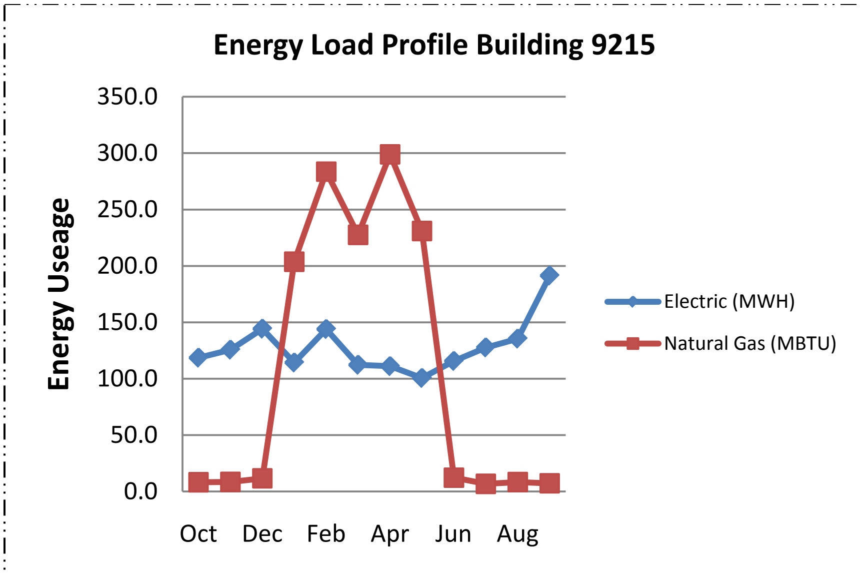

Figure 28. Energy load profile building 9215

The hangars at Miramar exhibit a larger amount of natural gas use than would be expected from unconditioned space. The average EUI of 55 for the hangars is more similar to that of an office building than a warehouse. The warehouses at Miramar had an EUI of 19. It is expected that the hangars would have an EUI similar to this if they were primarily unconditioned space with limited hot water usage.

***Potential Improvements*:**

- NREL observed that the lighting control systems were not functioning properly in every hangar; hangars with adequate daylighting had lights turned on during the day. NREL recommends ensuring that lighting controls are functioning properly and that controls are not being overridden on a continual basis. The U.S. Environmental Protection Agency (EPA) estimates that warehouses have a 45% to 80% potential energy savings when using lighting occupancy sensors. Interior lighting is typically the largest energy user in an unrefrigerated warehouse; therefore, there is significant energy savings potential from properly using lighting occupancy sensors and having the sensors commissioned to function properly.
- The hangars were found to contain large domestic hot water boilers and tanks. The domestic hot water loads in the hangars are estimated to be minimal and the systems are likely oversized. NREL recommends installing either a smaller-sized boiler or on-demand electric heating units at sinks in the hangar.
- Several of the hangars use propane fuel for water and space heating. This is because the natural gas pipeline does not extend to all of the hangars. NREL recommends extending the pipeline and using natural gas for these systems. This will provide cost savings and GHG reduction.
- In the previous efficiency analysis, several lighting upgrades were recommended for the high bay lighting systems in the hangars. It appears that several of these recommendations have already been implemented to reduce lighting load. However, these suggestions should be revisited to ensure that they have all been implemented.

Findings without recommended improvements: The hangars contained daylighting systems, they contained lighting controls, and they were largely unconditioned.

Barracks. The barracks in Area 5 of the Main Base at Miramar provide housing for the remaining service personnel on the base. The barracks are dormitory-style housing. The buildings are heated and cooled by several centralized plants. Pictures of several of the barracks and some of the heating systems are shown in the following figures:

Figure 29. Barracks buildings (Credit: Samuel Booth, NREL)

Figure 30. Hot water storage tank 5710 (Credit: Samuel Booth, NREL)

Figure 31. Boilers in 5710 (Credit: Samuel Booth, NREL)

Load profiles for several of the buildings that provide centralized heating are shown in the following figures. Building 5702 contains the hot-water heating systems that feed heat pumps in approximately half of the barracks. Building 5710 contains domestic hot-water heating systems. Building 5402 represents the typical electrical load of a barracks facility.

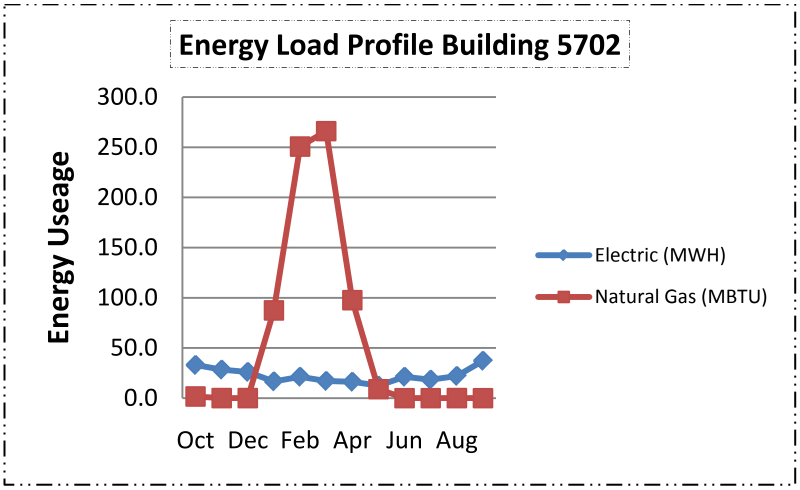

Figure 32. Energy load profile building 5702

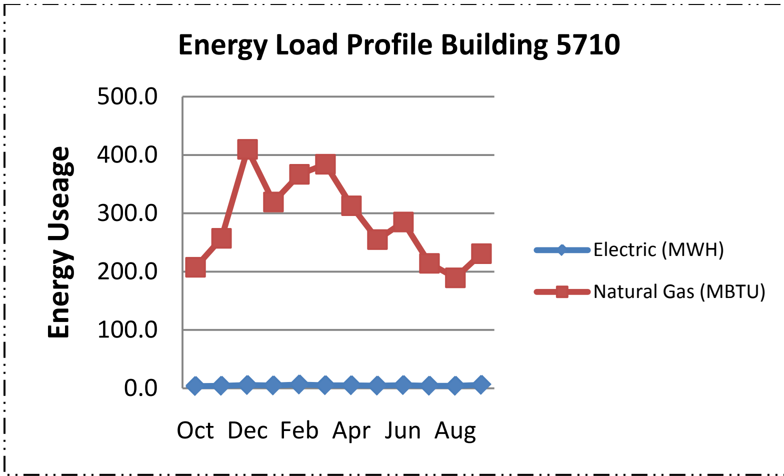

Figure 33. Energy load profile building 5710

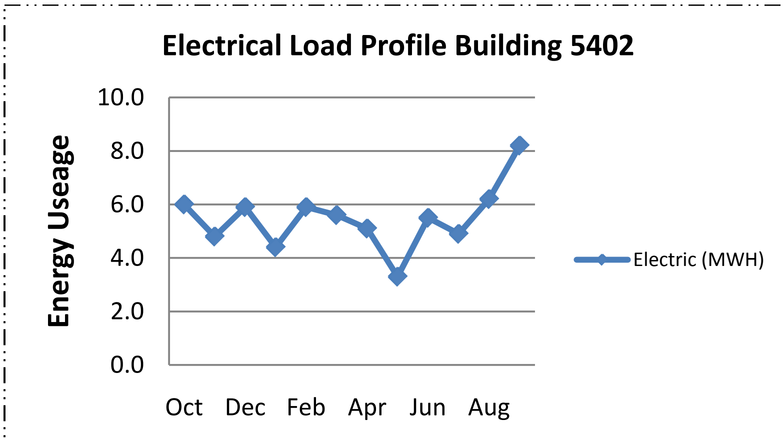

Figure 34. Electrical load profile building 5402

Potential Improvements:

- Replace barracks refrigerators with more energy-efficient units.
- Install occupancy monitoring devices such as card readers to ensure that non-occupied units are not being heated or cooled.
- Replace centralized heating systems with renewable powered CHP systems (see section on CHP for more information).

Other Facilities. Facilities in the "other" category comprise the large fraction of base area. There are 282 facilities listed in this category. These facilities total 1,773,200 ft^2 and 29% of the total base square footage. The average facility size is 6,288 ft^2. EUI data were obtained for 63 of these facilities with the average EUI of 208. This average is skewed to the very high end by facilities such as flight simulators, compressed air plants, and aircraft fueling facilities that use large amounts of energy relative to their size. NREL recommends that these facilities be analyzed for energy efficiency improvement potential.

Commissary and Exchange. The Commissary and Exchange are on-site commercial facilities operated by the Defense Commissary Agency that provide goods and services to military personnel and their families. These facilities are not controlled by the base energy manager and receive separate utility bills. NREL was able to obtain the energy consumption data for the Commissary, but not for the Exchange. The Commissary averaged 3,936 MWh per year of electrical energy consumption between 2001 and 2008 with no significant change in annual consumption. The natural gas use at the Commissary has varied substantially in this time from annual consumption in the range of 644 MBtu per year to 3,880 MBtu. NREL used the time period from June 2007 to June 2008 for its conservative baseline of 1,252 MBtu per year. Using 3,936 MWh and 1,252 MBtu, the EUI for the 103,539 ft^2 Commissary is 141. The Commissary represents 6.4% of total base electrical energy consumption and 1.0% of total base natural gas consumption. The average food sales building in the 2003 Commercial Building Energy Survey has an EUI of 200.[26] The average energy use breakdown of a food sales building is shown in Figure 35.

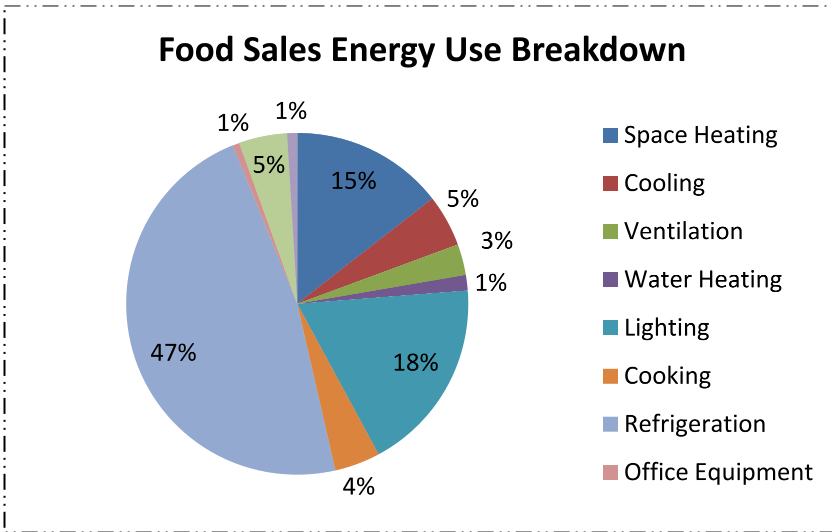

Figure 35. Food sales energy use breakdown

The end use of energy at the Exchange at Miramar would likely be similar to that of a retail store in the Commercial Building Energy Survey. The end use breakdown is shown in Figure 36.

[26] EIA. "2003 Commercial Building Energy Consumption Survey, Energy End-Uses, October 2008, Table E.2A. http://rfflibrary.wordpress.com/2008/10/15/2003-commercial-buildings-energy-consumption-survey-detailed-tables/. Accessed April 2010.

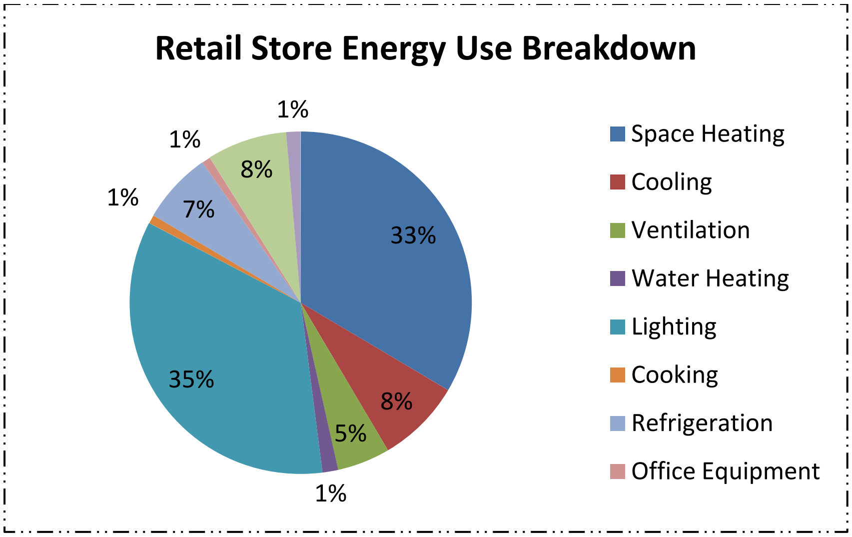

Figure 36. Retail store energy use breakdown

NREL conducted brief walkthroughs of the main areas of the Commissary and the Exchange, and did not visit the building mechanical rooms. Several opportunities for savings were identified.

Potential Improvements:

- The majority of the energy use at the Commissary is estimated to come from refrigeration. 85 W T-12 lights are being used in the freezers and each freezer contains 26 light bulbs. There are two freezer sections in each row and four rows of freezers. NREL recommends switching the light bulbs in the freezers to LED bulbs to save both cooling and lighting energy. The current incandescent bulbs release significant amounts of heat and increase the refrigeration energy requirements. Additionally, NREL recommends installing light sensors on the freezers. Savings from the reduced lighting load are estimated to be approximately 100,000 kWh per year or 341 MBtu. The heat produced by the bulbs increases energy requirements for the freezers 25% to 50%.[27] Assuming a 37% reduction in refrigeration load, and assuming that 47% of the total Btu is used for refrigeration, the savings would be 748 MWh or 2,553 MBtu. Total savings for this project would be 2,894 MBtu.
- NREL recommends that the Commissary use waste heat from refrigeration to reduce its heating load requirements. Heating load is estimated to comprise 15% of the energy use in an average food sales store. Assuming a savings of 5% of the Commissary's natural gas load, the savings would be 63 MBtu.
- The Exchange contained large numbers of small halogen light bulbs. NREL recommends switching these halogen bulbs to LED bulbs that provide the same lighting characteristics but use substantially less energy. Assuming there are 500 50W halogen bulbs, the savings would be approximately 73,000 kWh or 249 MBtu. These lights are shown in Figure 37.

[27] *Lighting the Way to Greener Retail*. Nualight. www.nualight.ie/datasheets/Research_Paper_05_08.pdf. Accessed April 2010.

Figure 37. Exchange shopping area (Credit: Samuel Booth, NREL)

Findings without recommended improvement: Lighting levels in the Commissary were appropriate.

Brig. The Brig at Miramar is a separate facility complex located in Area 7. The brig facilities are not controlled by the Miramar base energy manager and receive their own utility bills. The brig contains approximately 151,223 ft^2 of facility space. The baseline energy consumption for the Brig is 2,657 MWh and 15,637 MBtu. This represents 4.4% of total base electrical energy consumption and 12.2% of total base natural gas energy consumption. The Brig has an EUI of 163.

The Brig is outside the control of the base energy manager and was not assessed for energy efficiency improvement potential. However, it was recently announced that the Brig will be replacing boilers and installing two microturbine systems.[28] This project will likely significantly reduce the energy consumption at the Brig.

4.6 Privatized Housing

The Miramar installation contains a large number of housing units for military personnel and their families. These units are operated and managed by Lincoln Military Housing. The housing facilities are not controlled by the Miramar base energy manager and receive their own utility bills. The residents of the housing facilities receive unlimited utilities with their rent, so they have limited incentive to conserve.[29] There are approximately 223 structures, containing approximately 527 housing units on base at Miramar. The majority are multiple-unit townhouse-style units. However, there are single family homes available for officers and select enlisted individuals. The approximate size breakdown is 183 two-bedroom units, 168 three-bedroom units, 126 four-bedroom units, and 50 five-bedroom units. [30] The size of units ranges from approximately 950 ft^2 for a two bedroom townhouse to approximately 2,500 $ft^2$for the largest four bedroom a single family home.[31] The total

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[28] Recovery Act to Replace Boilers at San Diego Marine Air Station. NAVFAC. https://portal.navfac.navy.mil/portal/pls/portal/APP_PAO.PRESS_RELEASE_FULL_DYN.show?p_arg_names=newsid&p_arg_values=3487. Accessed 2010.
[29] Base Energy Manager Randy Monohan.
[30] CNIC: Commander Navy Region Southwest Web site: www.cnic.navy.mil/cnrsw/OperatingForcesSupport/OperatingSupport/HousingTypes/index.htm. Accessed April 2010.
[31] Size estimate based on floor plans available from Lincoln Military Housing Web site: www.lincolnmilitary.com/Installations/miramar-(mcas)/. Accessed April 2010.

interior square footage of the houses is 750,000 ft^2. Many of the structures also have attached garages, which are not heated or cooled. The total square footage of the garage space is 186,000 ft^2. The housing units and garages comprise a total of 936,000 ft^2; the average unit size is 1776 ft^2. Privatized housing accounts for 15.4% of the total square footage on base. The total annual electrical energy use for the privatized housing units is 4,089,791 kWh, and natural gas use is 7,990 MBtu. Privatized housing represents 6.8% of the total base electrical load and 6.3% of the total base natural gas load.

When analyzing the EUI of the housing units, NREL was able to obtain EUI numbers for 134 of the 223 structures. The average EUI was 45 kBtu per ft^2. The EUI of a typical house in the Pacific Division of the Western Census Unit is 42.[32] Thus, the units have an energy consumption slightly above the average. To assess the potential for additional energy efficiency improvements in the housing units, NREL conducted energy analysis walkthroughs of a single family house and a townhouse located within a four-unit structure. NREL found significant energy savings potential in each unit.

Townhouse. The first unit NREL visited was townhouse 1440 C (Figure 38). This was a two-bedroom townhouse with a size of approximately 1200 ft^2 located in a structure with three other townhouse units.

Figure 38. Townhouse building 1440 (Credit: Samuel Booth, NREL)

The energy load profile for the entire structure in FY 2009 is shown in Figure 39.

[32] EIA. 2005 Residential Energy Consumption Survey. Data from Pacific Division, Western Census Unit. Table US1. Total Energy Consumption Expenditures and Intensities, 2005. www.eia.doe.gov/emeu/recs/recs2005/c&e/summary/pdf/tableus1part1.pdf. Accessed April 2010.

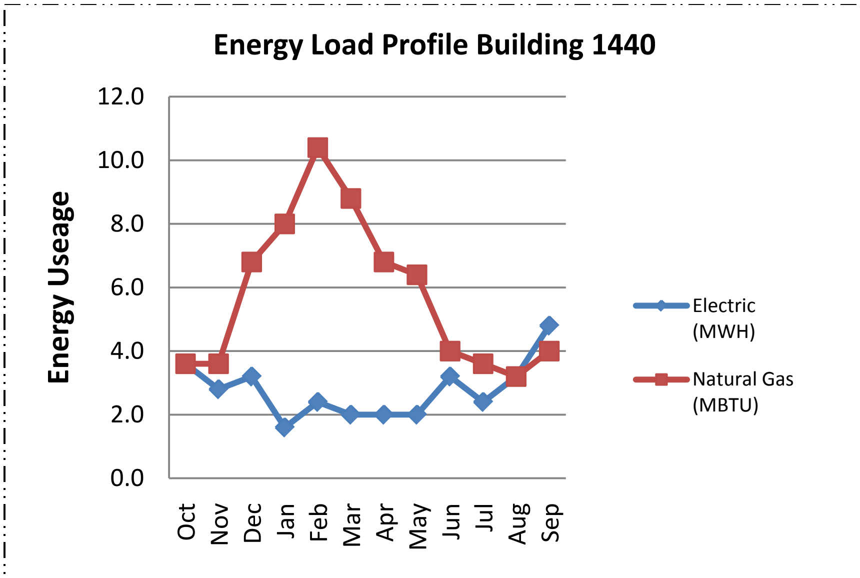

Figure 39. Energy load profile building 1440

Potential energy efficiency improvements and savings:

- ✓ The house did not contain a programmable thermostat. NREL recommends installing a programmable thermostat to save heating and cooling energy. The installation of programmable thermostats is projected to save 351 kWh and 3 MBtu of natural gas per unit. Assuming that 75% of units do not have programmable thermostats, the savings would be 138,645 kWh and 1,185 MBtu. A savings calculation spreadsheet is provided in Appendix E.
- ✓ NREL observed that the water heater in the unoccupied house was left on, and recommends turning off water heaters in unoccupied housing units to reduce natural gas used to maintain tank temperature. Turning off water heaters in unoccupied units would save 0.4% of the total natural gas consumption assuming that 5% of the units are unoccupied at any given time. Detailed savings calculations are provided in Appendix E.
- ✓ Lighting Savings:
  - NREL recommends replacing kitchen lighting with three 25 W T-8 bulbs. Lighting in kitchen was provided by four 40 W T-12 bulbs.
    - ♦ Lighting savings in the kitchen = 124.1 kWh.
  - NREL recommends replacing garage lighting with two 25 W T-8 bulbs. Lighting in garage was provided by two 40 W T-12 bulbs.
    - ♦ Lighting savings =5.4 kWh.
  - NREL recommends reducing the light level in the upstairs bathroom and replacing lighting with a single T-8 bulb of either 32 W or 25 W. Lighting was provided by two 40 W T-12 bulbs. Light level was very high, measuring 100 foot candles.
    - ♦ Lighting savings = 26 kWh.
  - The total lighting savings would be 61,423 kWh (155.5 kWh x 395 units).
- ✓ Energy savings from reduced water use:
  - NREL recommends new fixtures to reduce flow rate and water consumption. Sink flow rates could be reduced in the kitchen and upstairs and downstairs bathrooms from the current 2.2 gallons per minute (GPM).

    - 2.2 GPM is the required flow rate according to California code. However, California's green building statue recommends a 1.8 GPM flow rate.
  - NREL recommends replacing the current fixture with a new lower-flow shower head to reduce water consumption and water heating requirements. Flow rate in upstairs shower was 2.5 GPM.
    - 2.5 GPM is the required flow rate according to California code. However, California's green building statue recommends a 2.0 GPM flow rate.
  - NREL recommends replacing standard faucet and shower fixtures with low flow fixtures.
    - Assume standard faucet has a flow rate of 2.2 GPM
    - Assume low flow faucet has a flow rate of 1.8 GPM
    - Assume standard shower has a flow rate of 2.5 GPM
    - Assume low flow shower has a flow rate of 2.0 GPM
    - Assume the average person uses 20 gal/day of hot water using standard fixtures
    - Assume the average person uses 16.1 gal/day of hot water using low flow fixtures
    - Annual energy savings per person = 0.623 MBtu/yr
    - Number of people = 1,218
    - Annual energy savings = 759 MBtu/yr
- ✓ NREL recommends replacing appliances in the unit (air conditioner, refrigerator, washing machine, and dishwasher) with more efficient models.
  - NREL recommends replacing standard refrigerators with ENERGY STAR refrigerators.
    - Assume ENERGY STAR refrigerators use 20% less energy
    - Annual energy savings per unit = 53 kWh/yr
    - Number of units = 395
    - Annual energy savings = 20,948 kWh/yr
  - NREL recommends replacing the standard washer with an ENERGY STAR washer.
    - Assume ENERGY STAR washers use 33% less energy
    - Annual energy savings per unit = 160 kWh/yr
    - Number of units = 395
    - Annual energy savings = 63,240 kWh/yr
  - NREL recommends replacing the standard dishwasher with an ENERGY STAR dishwasher.
    - Assume ENERGY STAR dishwashers use 31% less energy
    - Annual energy savings per unit = 145 kWh/yr
    - Number of units = 395
    - Annual energy savings = 57,311 kWh/yr

Findings without recommended improvements:

- Unit contained double pane windows.
- Furnace filters were found in good condition.
- Furnace was high efficiency model.
- Attic contained insulation.
- Toilets were 1.6 gallons per flush.

- Unit contained natural gas range.
- CFL light bulbs in fixtures outside unit.
- T9 fluorescent lights in several locations.

Single Family House. The second unit visited was a single family house unit 1416 (Figure 40). This was a four bedroom house that was approximately 2000 ft^2.

Figure 40. Single family house 1416 (Credit: Samuel Booth, NREL)

The FY 2009 load profile for this unit is shown in Figure 41.

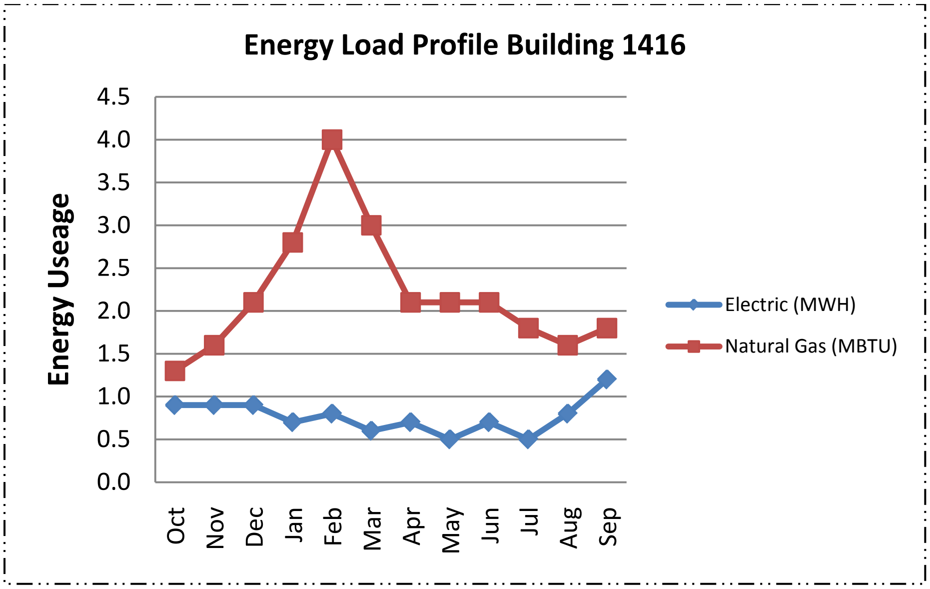

Figure 41. Energy load profile building 1416

Potential Improvements*:*

- ✓ Replace appliances with ENERGY STAR models.
  - ENERGY STAR appliance savings – Replace the standard refrigerators with ENERGY STAR refrigerators.
    - Assume ENERGY STAR refrigerators use 20% less energy
    - Annual energy savings per unit = 53 kWh/yr
    - Number of units = 132

    Annual energy savings = 6,983 kWh/yr
  - ENERGY STAR appliance savings – Replace the standard washer with an ENERGY STAR washer.
    - Assume ENERGY STAR washers use 33% less energy
    - Annual energy savings per unit = 160 kWh/yr
    - Number of units = 132

    Annual energy savings = 21,080 kWh/yr
  - ENERGY STAR appliance savings – Replace the standard dishwasher with an ENERGY STAR dishwasher.
    - Assume ENERGY STAR dishwashers use 31% less energy
    - Annual energy savings per unit = 145 kWh/yr
    - Number of units = 132

    Annual energy savings = 19,104 kWh/yr
- ✓ Replace sinks and showers with lower flow units.
  - Low flow fixtures – Replace standard faucet and shower fixtures with low flow fixtures
    - Assume standard faucet has a flow rate of 2.2 GPM
    - Assume low flow faucet has a flow rate of 1.8 GPM
    - Assume standard shower has a flow rate of 2.5 GPM
    - Assume low flow shower has a flow rate of 2.0 GPM
    - Assume the average person uses 20 gal/day of hot water using standard fixtures
    - Assume the average person uses 16.1 gal/day of hot water using low flow fixtures
    - Annual energy savings per person = 0.623 MBtu/yr
    - Number of people = 406

    Annual energy savings = 253 MBtu/yr
- ✓ Replace 65 W incandescent bulbs located throughout the house with CFLs.
  - Two lobby, 4 living room, Two in each bedroom (a total of eight), five in upstairs bathroom, five in upstairs living space.
  - Fans had two 60 W bulbs on each of them. House had six fans.
  - Lighting replace 36 incandescent bulbs with CFLs.
  - Total savings is 138,150 kWh.

- ✓ The back yard of the single family house contains a large grass area with sprinklers. This could be replaced with less water-intensive landscaping.
- ✓ The front yard contains sprinklers that were watering the bark area, but not the plants. Water use could be reduced by optimizing sprinkler water use and placement.

Findings without recommended improvements*:*

- ENERGY STAR programmable thermostat present
- Garage contains a T-8 fixture with four 32 W bulbs

- Double pane windows present
- Gas dryer
- Kitchen contained four 32 W T-8 bulbs
- Water heater received good energy efficiency rating

5 Renewable Energy and Additional Load Reduction Projects

5.1 Overview

NREL conducted additional analysis on promising renewable energy and fossil fuel reduction technologies to achieve progress towards a NZEI at Miramar. Each of the technologies evaluated is presented in the following section.

5.2 Solar Pool Heating

Miramar should consider solar water heating systems for its pools.[33] Solar pool heaters raise the temperature of a relatively large amount of water to approximately 80°F by circulating water relatively quickly. These are different systems than solar domestic hot water heating systems, which raise the temperature of a small amount of water to approximately 140°F. This distinction between solar pool and solar domestic water heating systems allows most of the solar energy falling on the collector to transfer to the pool. A simple schematic of solar pool heat is shown in Figure 42.

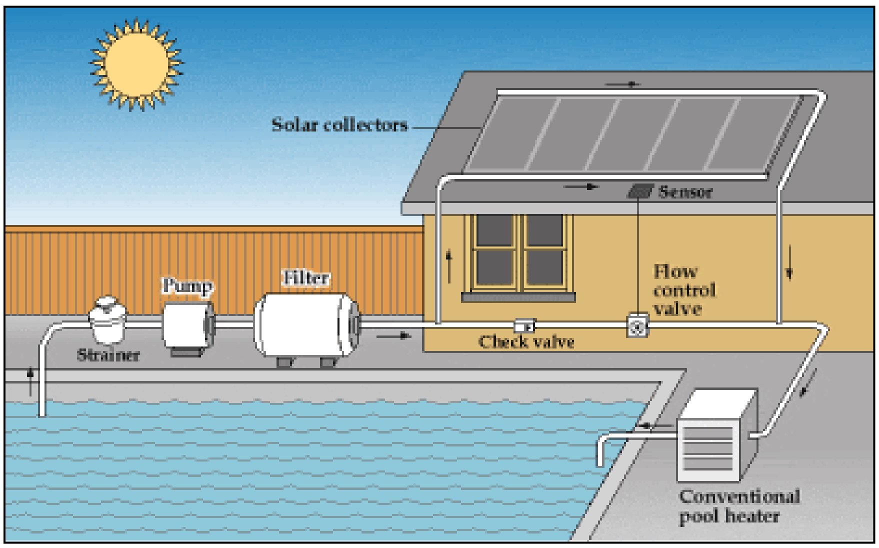

Figure 42. Solar pool heater schematic[34]

The base has several small pools located in the community centers near base housing, a 25-meter pool in the officers club, and a 50-meter pool used for water survival training and recreational swimming.

NREL conducted an analysis of converting the large 50-meter pool to a solar water heating system. The pool is located in facility number 2169. This facility contains the large 50-meter pool, a small wading pool, and showers. The average natural gas usage for this complex over the last three fiscal years was 7,562 MBtu. This represents 5.4% of the total baseline natural gas use. NREL assumed that 95% of the natural gas load for this complex was used for water heating for the pools. Assuming the Miramar pool is a standard Olympic-sized pool, the width would be 25 meters and the depth would be 2 meters. This size pool would contain 660,000 gallons of water. Savings potential is discussed below.

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[33] During the process of writing this report, Miramar began construction of a new 50 meter pool that will include a solar pool heating system. The old pool is scheduled for demolition following completion of the new pool.
[34] DOE. Example of a Solar Pool Heating system, www.energysavers.gov/your_home/water_heating/index.cfm/mytopic=13230.

Pool Covers. Pool covers would save the base a large amount of energy if they are not currently being used. Outdoor pools lose energy in three main ways, which are shown in Figure 43.

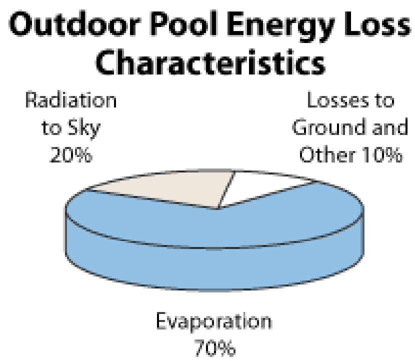

Figure 43. Pool energy losses[35]

Losses from evaporation not only result in an enormous energy loss but they also require replacement with new water. Water is a precious resource in Southern California and Miramar has undertaken significant water conservation measures. Pool covers reduce the amount of makeup water needed by 30% to 50%.[36] Pool covers cost approximately $2 per square foot and have simple paybacks of about half a year. Before installing a solar pool water heating system, the base should ensure the pools are properly covered to save both water and energy.

Solar Thermal Pool Heating System

Size: The desired size for a solar pool heater is typically between 50% and 100% of the surface area of the pool itself. The ideal system size depends on factors such as: whether the pool is covered, local weather conditions, system type, system location relative to the sun, and number of days the pool is open. For a system sized to 100% of the pool surface area, the collectors would be 13,450 ft^2. The solar collectors can be located on ground mounts or roof tops.

Energy Savings: NREL used a Solar Pool Economics Calculator from Sandia National Laboratory to determine an approximate energy savings for the system.[37] Solar resource data for San Diego were put into the calculator, along with the current natural gas consumption and pool size. The pool was assumed to be used year round and have a desired temperature of 80°F. A system size of 13,450 ft^2 would produce approximately 5038 MBtu per year or about two thirds of the energy required to heat the pool. The estimated cost for the system was $15 per square foot, so the total cost for this system would be $201,750. The estimated levelized cost of energy produced by the system is approximately $4 per MBtu. Miramar's natural gas rate varies between $10 and $25 per MBtu. At a rate of $10 per MBtu the system would save $50,376 per year and have a simple payback of four years. At a rate of $20 per MBtu, the system would save $100,753 per year and have a simple payback of two years.

The officer's club pool at Miramar is a 25-meter pool that is also a good candidate for a solar pool heater. The pool does have a different operating schedule than the larger pool; however, it still has a

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[35] U.S. Department of Energy. Energy Savers. Swimming Pool Covers. www.energysavers.gov/your_home/water_heating/index.cfm/mytopic=13140. Accessed April 2010.
[36] U.S. Department of Energy. Energy Savers. Swimming Pool Covers. www.energysavers.gov/your_home/water_heating/index.cfm/mytopic=13140. Accessed April 2010.
[37] Sandia National Laboratories. Solar Pool Economic Calculator. http://energy.sandia.gov/engineeringtools.htm. Accessed April 2010.

large natural gas load. The approximate natural gas consumption for this pool facility is 1,700 MBtu. Assuming two thirds of this energy could be met with a solar pool heater, an additional 1,142 MBtu could be saved.

Many other facilities in California including other military installations such as Camp Pendleton and the 32nd Street Naval Station San Diego have installed solar pool heaters. If Miramar installed solar pool heating systems on its 50-meter and 25-meter pools, it would save approximately 6,200 MBtu per year or 4.7% of total baseline natural gas consumption. The technology, which is simple and mature, has an attractive payback of two to four years.

Recommendation: Install solar pool heaters for the main 50-meter swimming pool, the 25-meter officers' club pool, and if feasible, the community center pools.

5.3 Additional Solar Hot Water

There is potential for additional solar hot water systems beyond the eight systems that the base plans to install with its boiler replacement project. The boiler replacement project is targeting base areas 6, 7, 8, and 9. However, additional buildings in areas 2, 4, and 9 that are not yet planned for boilers replacements could be retrofitted with additional solar hot water systems.

The natural gas loads of high use buildings in these additional areas were analyzed for solar hot water potential. Several buildings were found to be good candidates for additional systems. They are listed in Table 14.

Table 14. Potential Candidates for Solar Hot Water System

Building Number	Name	Area (Sq. Ft.)	Type	Natural Gas MBtu
2002	Fitness Center	24,620	Other	363
2471	Fitness Center	32,826	Other	2,462
2496	Medical Clinic	51,823	Medical Center	3,737
2515	Temporary Lodging Facility	18,833	Other	1,126
4312	Combined Bach. Officers Qtr	50,123	Office	1,859
4325	Combined Bach. Officers Qtr	26,612	Dwelling	2,758
9215	Aircraft Maint Hangar	127,904	Hangar	1,308
9277	Aircraft Maint Hangar	133,694	Hangar	2,159
9500	Aircraft Maint Hangar	84,101	Hangar	1,903
Total		**550,536**		**17,673**

The natural gas load profile for these buildings is shown in Figure 44.

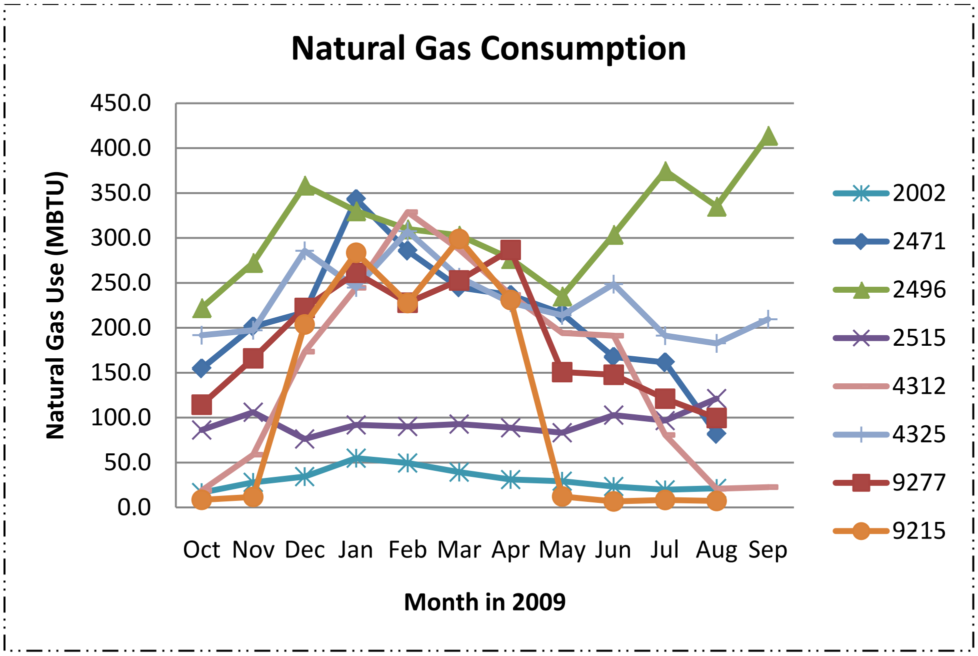

Figure 44. Natural gas consumption

The load profiles for these buildings were used to estimate the end use of natural gas for water heating and space heating. Buildings with flat profiles indicate that a majority of natural gas use is for water heating rather than space heating. Large spikes in load profiles in the winter months indicate high use for space heating. For buildings such as lodging and fitness facilities, high natural gas use for water heating seems reasonable. As mentioned in the energy efficiency section, the natural gas loads for buildings 9215, 9500, and 9277 appear to be high for buildings categorized as hangars. However, if there is a substantial hot water load for these hangars (which appears to be the case), solar thermal systems would be beneficial. The base already has plans to install a solar thermal system on hangar buildings 9215 and 9670. Building 9670 is not shown in this analysis because it uses propane and its consumption is unknown. Estimates for end use for water heating and solar thermal savings potential are shown in Table 15.

Table 15. Potential Candidates for Solar Hot Water System

Building Number	Natural Gas MBtu	Estimate % Hot Water Load	% Served by Solar Thermal	MBtu Reduction
2002	363	75%	60%	163
2471	2,462	80%	60%	1,182
2496	3,737	95%	60%	2,130
2515	1,126	90%	60%	608
4312	1,859	65%	60%	725
4325	2,758	95%	60%	1,572
9215	1,308	30%	60%	235
9277	2,159	75%	60%	971
9500	1,903	60%	60%	685
Total	17,673			8,272

NREL did not conduct detailed analysis of building orientation, building roof types, or building roof space for these solar hot water systems. Not all of these buildings may be able to implement solar hot water systems, so further analysis is needed. A sample payback is shown in Table 16 for the installation of solar hot water systems on all buildings except 4325 and 2496.[38]

The estimated savings from solar hot water systems in terms of natural gas displaced at these other buildings is 4,570 MBtu.

Table 16. Solar Hot Water Financial Estimate

Solar Water Heating Area (ft^2)	13,565
Solar Water Heating Delivery (MBtu)	3656
Solar Water Heating Initial Cost ($)	$1,356,500
SWH Rebate ($)	$75,000
SWH Federal Tax Credit ($)	$384,450
Solar Water Heating Cost w/incentives ($)	$897,050
Solar Water Heating Gas Savings (MBtu/yr)	4,570
Solar Water Heating Annual Utility Cost Savings ($/yr)	$47,304
Solar Water Heating O&M Cost ($/yr)	$6,783
Solar Water Heating Payback Period (yrs)	22

[38] Buildings 4325 and 2496 were also good candidates for microturbines. Further analysis is needed to determine the optimal energy technology for each building.

Recommendation*:* Install additional solar hot water systems wherever feasible at Miramar. Prioritize buildings in areas 2, 4, and 9 that were not covered in the previous boiler replacement project.

5.4 Combined Heat and Power

The potential exists for Miramar to use CHP systems. CHP systems produce both thermal energy that can be used for space heating, cooling, or water heating and electrical energy that can be fed back into the base's distribution network. These systems often use natural gas; however, they can be configured for a variety of fuels such as biomass, propane, diesel, biogas, and kerosene. Use of a CHP system would not only provide Miramar with cost savings opportunities, but also allow the base to reduce its energy footprint. Miramar has a small centralized hot water and steam distribution networks in two areas that could benefit from a CHP system. The following are various technologies to consider for CHP.

5.4.1 Natural Gas Powered Cogeneration

Base areas 5 and 8 have enough thermal loads that they could be supplied by a cogeneration unit with a size range of 1 MW to 2 MW. Cogeneration units are typically used in large-scale residential, commercial, or industrial applications. System sizes are typically at least 500 kW. The most common technology used for a cogeneration system is a natural gas powered turbine or engine. However, a natural gas powered cogeneration unit would not be the ideal option for Miramar. Other units such as fuel cells are eligible for California's Self Generation Incentive Program (SGIP) and would provide improved economics. Additionally, Miramar's goal is to become a NZEI. A natural-gas-powered cogeneration unit would reduce source Btu, but would still require natural gas use, which is a non-renewable fuel.

5.4.2 Microturbines

Technology Overview*.* Microturbines are small combustion turbines with outputs between 5 kW and 500 kW and are better suited to supply the load of individual buildings at Miramar than cogeneration units, which are typically much larger.

These systems are most cost-effective when the user is able to take advantage of both the thermal and electrical loads produced by the system. Electrical efficiency is typically between 15% and 40% and thermal use can make the total efficiency as high as about 90%. Figure 45 illustrates the microturbine energy generation process.

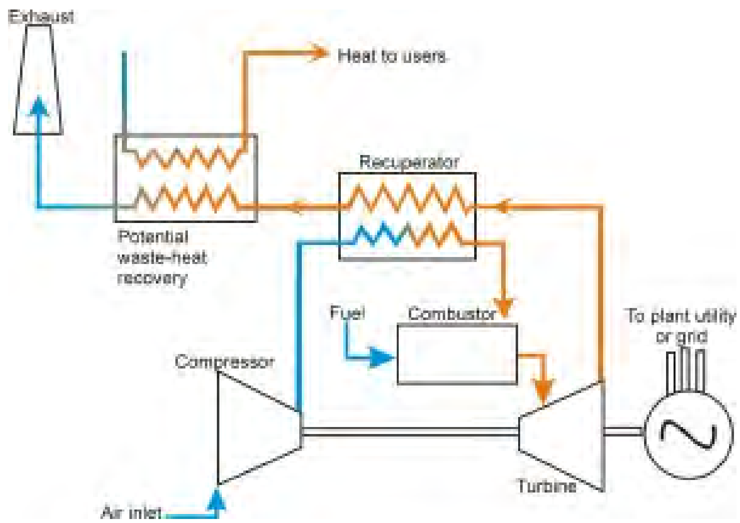

Figure 45. Schematic of a microturbine[39]

Planned and Existing Projects. On October 29, 2009, The Brig at Miramar announced that it has received funding under ARRA to replace boilers and install two CHP microturbines.[40] NREL was unable to obtain an estimate of the energy savings from this project from NAVFAC.

Currently the Naval Base in Coronado near Miramar uses two 60 kW microturbines to produce 120 kW of electricity. These turbines also displace 700,000 Btu per hour from the natural gas-fired hot water heater. This system saves the base $78,000 annually.[41] A picture of a sample microturbine unit is shown in Figure 46.

PIX # 08130

[39] DOE Industrial Technologies Program. Industrial Distributed Energy. www.eere.energy.gov/de/microturbines/tech_basics.html. Accessed April 2010.
[40] Recovery Act Will Replace Boilers at San Diego Marine Air Station, NAVFAC Southwest. https://portal.navfac.navy.mil/portal/page/portal/navfac/navfac_ww_pp/navfac_navfacsw_pp/news/mcas_miramar-replace_boilers_bestek_16sept09.pdf. Accessed April 2010.
[41] Renewable Energy and Distributed Generation Projects, Navy Region Southwest. June 2006. https://portal.navfac.navy.mil/portal/page/portal/navfac/navfac_ww_pp/navfac_navfacsw_pp/solarpower_forum/nrsw_re_brochure_june-06.pdf. Accessed April 2010.

Figure 46. 30 kW Capstone microturbine units (Courtesy of Capstone Turbine Corporation)

Analysis. NREL conducted an analysis to determine the potential for microturbines on the Main Base at Miramar. 23 buildings at Miramar were found to have natural gas loads above 1,500 MBtu annually, which make them good candidates for microturbines. The majority of these buildings were eliminated from further analysis because they were either in area 5 or area 8, which were better suited to centralized systems or were already receiving a new boiler and/or solar hot water system. However, most of buildings listed in the solar hot water section of this report would also make good candidates for micro turbine systems. The typical microturbine systems size for these buildings ranges from 30 kW to 60 kW. Microturbines can be coupled with existing building energy systems and should be sized so that the heat output of the turbine is less than the building's load. It is possible that other buildings at Miramar could also be good candidates for microturbines, and it is possible these particular buildings would be better suited to solar hot water systems. However, regardless of the specific buildings chosen, microturbines are a cost-effective and reliable technology that would lower the energy baseline at Miramar.

NREL conducted an analysis of the estimated cost and payback for a microturbine system, based on the natural gas load of 2,000 MBtu annually. The median load from the list of 23 candidate buildings was 2,643 MBtu of annual natural gas consumption. The heat from the microturbine can also be used in conjunction with an adsorption chiller to provide cooling for a building. This potential electrical load reduction was not accounted for in this analysis. Data are provided in Table 17.

Table 17. Microturbine Analysis

Base Case Natural Gas Heating	
Natural Gas Load (MBtu)	2000
Estimated Boiler Eff.	80%
Heating Btu Required	1600
Natural Gas Cost ($ / MBtu)	10.35
Total Natural Gas Cost	$20,700
Micro Turbine CHP	
Microturbine Elec. Eff.	25%
Microturbine Thermal Eff.	35%
Total Eff.	60%
Natural Gas Load (MBtu)	4571
Heating Btu Required	1600
MBtu Converted to Electric	1143
kWh Produced	334,854
Natural Gas Cost ($ / MBtu)	$10.35
Total Natural Gas Cost	$47,314
Value of Electrical Energy (per kWh)	$ 0.16
Total Electrical Energy Value	$53,577
System Size Required (kW)	38

Installed System Size (kW)	60
Installed Cost ($/kW)	$2,175
Total Cost	$130,500
Annual Maint. ($/kW)	$ 0.011
Annual Maint. Cost	$3,516
Annual Saving	$23,446
Simple Payback (yrs)	6

Sensitivity Analysis. The economics of a microturbine system are particularly attractive for Miramar at their current energy prices. However, Miramar's natural gas rates have fluctuated between $10 and $25 per MBtu over the last few years, while the electric rates have varied considerably less. In order to justify the capital cost for a microturbine installation, the cost of a Btu of natural gas energy needs to be approximately 40% less than the cost of a Btu of electrical energy. With an electricity price of $0.16 per kWh, natural gas would need to cost less than about $17.50 per MBtu to make microturbines attractive at Miramar.[42] At a natural gas price of $17 per MBtu, the system payback time is about 28 years for an electrical energy price of $0.16 per kWh. However, at the current price of about $10 per MBtu, the payback is about six years. Additionally, when replacing old boilers at Miramar, the base should compare the capital cost of a new boiler with a microturbine system, this scenario would likely provide even more favorable economic conditions for the installation of a microturbine.

In addition to economic benefits, microturbines reduce source energy use. The reduction comes from the difference between electrical energy generated on-site as in the case of a microturbine, as compared to electricity purchased from the grid. For the microturbine case, the net of rate energy use in terms of Btu per kWh was calculated to be 6826 Btu per kWh.[43] This would result in a reduction of 3,750 source Btu's per kWh of electrical energy produced. For our sample case above, the savings would be approximately 1,700 source MBtu per year.

Microturbine Recommendation: NREL recommends that Miramar further examine the installation of microturbines across the base in buildings that do not have either a central space and water heating systems or a solar hot water heating system. Solar hot water systems would be preferable to microturbines because they do not require fossil fuel energy. However, not all buildings are appropriate for these systems. Microturbines would strengthen the microgrid at Miramar due to their ability to provide backup power in the event that a power outage occurs . Potential target buildings for initial microturbine projects are buildings 4312, 4325, and 2496. As microturbine systems are further analyzed, Miramar should monitor natural gas prices to ensure that microturbines remain a cost-effective energy generation option. Using microturbines with conventional natural gas will lower the base's overall carbon footprint because the electrical energy will be generated with natural gas which is a lower-carbon fuel than the average generation mix of SDG&E, and the waste heat from the generation process will be used on base. It will increase site

[42] 1 kWh of electricity = 3413 site Btu's. At $0.16 per kWh electricity costs $46.88 per site MBtu. A natural gas price of $15.50 per MBtu would equal a ratio of .33 ($15.50/$46.88).
[43] Net rate (Btu/kWh) = (total fuel input into CHP system – fuel normally used to generate the same amount of thermal output as the CHP system output, assuming efficiency of 70%)/CHP electric output (kWh).

Btu use, but reduce source energy use.[44] NREL recommends that Miramar evaluate renewable natural gas supplies and use them in the proposed microturbines. Using renewable natural gas to power their turbines would increase net zero energy potential and further reduce the base's energy footprint.

5.4.3 Fuel Cells

Technology Overview. Fuel cells offer another option for CHP at Miramar. Fuel cells have high efficiency and low emissions, as compared to other conventional cogeneration systems. In addition, the California SGIP, which is designed to encourage on-site power generation, could provide generous incentives. This program allows only two types of technologies: wind turbines and fuel cells. Through this incentive program, the economics for a fuel cell CHP system are significantly improved.

There are several different types of fuel cells, including proton exchange membrane (PEM), solid oxide, molten carbonate, and phosphoric acid. The fuel source for these cells is typically hydrogen or a methane-based fuel, such as natural gas or renewably derived biogas. California's SGIP provides additional rebates to customers that install fuel cells on sites that use a renewable fuel source. Fuel cells with a renewable fuel source can generate incentives up to $4.50/W for the first 1 MW of capacity, an additional $2.25/W for capacity between 1 MW and 2 MW, and $1.125 for capacity between 2 MW and 3MW.[45] For large non-renewably powered fuel cells, the incentive drops to $2.50/W for capacity less than 1 MW, with the same 50% and 25% incremental decreases. Because the capital costs for a fuel cell are largely the same for a renewably powered fuel cell as they are for a non-renewably powered fuel cell, using a renewably powered system will likely produce improved system economics.

Islanding Mode. During a grid outage, the fuel cell power plant disconnects from the utility grid in milliseconds and is designed to continue to produce power to service the customer's critical loads. This "island" operation is designed to serve only dedicated loads (as well as the loads of the fuel cell system itself) and prevent any power to be exported to an otherwise unpowered utility grid. After the grid returns and is found to be stable, the fuel cell is designed to automatically synchronize its power to the utility grid while providing continuous power to the critical loads. If the customer does not require critical backup, then the fuel cell power system uses island mode to maintain power for its own process loads and to remain ready for reconnection to the utility grid when live-grid power is returned. This mode is called Island Hot Standby (IHSB).

Water Use. During full-power operation, the overall water consumption of a 2.8 MW system is approximately 13,000 gallons/day, and water discharge is approximately 6,500 gallons/day. Since the discharge water could be used with Miramar's grey-water program, the amount of extra water needed for Miramar is 6,500 gallons/day @ 365 days/year. A total of 2,372,500 gallons/year extra water is needed.

Analysis. In October 2009, a private sector company presented Miramar with the opportunity to have renewably powered fuel cells installed on base through a PPA (See the section 12 discussion of Implementation Options for more information on PPAs). This company partners with various

[44] The DOE provides guidance for energy managers to receive overall reduction credit for energy projects that increase site Btu but decrease source Btu. www.femp.energy.gov/femp/pdfs/sec502e_%20guidance.pdf.
[45] "Self-Generation Incentive Program." Center for Sustainable Energy, http://energycenter.org/index.php/incentive-programs/self-generation-incentive-program. Accessed April 2010.

engineering firms and financial institutions to provide fuel cells and renewable biogas. The electric power production from fuel cells is independent of the grid and as such, can offset the base load or serve as a clean source of backup energy when the grid is down. The company has an agreement with local producers of biogas and with SDG&E, whereby biogas can be treated by the company to pipeline quality and be placed into SDG&E's natural gas distribution network. Through this arrangement, the base could use natural gas directly from the pipeline, but would be purchasing the renewable natural gas. Additionally, the company could provide renewable fuel to the base through truck-based on-site fuel delivery as a second implementation option. For the purpose of this analysis, the biogas mentioned above, which is generated from landfills and waste-water treatment facilities and was previously flared, is considered a renewable fuel.

The likely fuel cell option in this scenario is the 1.4 MW DFC1500 made by Fuel Cell Energy. It is a molten carbonate fuel cell that is fueled by natural gas or cleaned biogas. The DFC1500 delivers high-quality base load electric power with 47% electric power generation efficiency. It provides approximately 11,500 kWh annually at the standard 13.8 kV AC voltage and 60 Hz. The air emissions, noise, and footprint of this fuel cell are all minimal. The DFC1500 also produces high-grade waste heat which is recoverable and can be distributed at various temperatures as hot water and/or steam. Heat energy is available by cooling the exhaust to various temperatures. A table is provided in the Application Guide[46] by Fuel Cell Energy with the estimated heat energy available for heat recovery (Btu/hr).

The opportunity presented to the base was a 10 to 15 year PPA for electrical energy supplied at $0.12 to $0.14 cents per kWh. The electrical energy price is dependent on if the base or the third party retains ownership of the emissions reduction credits. Additionally, the thermal energy provided by the fuel cell would be given to the base at no additional cost. Under this agreement the technology and operating risk are taken by the PPA provider and not the base.

NREL analyzed the economics and feasibility of installing two DFC 1500 fuel cell systems on Miramar under this PPA deal. The two areas on the base that were considered were the housing in Area 5 and the office space in Area 8. These two areas have significant natural gas loads that can be offset with the heat recovery system of the fuel cells. The fuel cell systems are sized based primarily on the thermal load that can be displaced in a particular area. The electrical energy produced by the fuel cell is put into the base distribution network and can be used anywhere on base however, the thermal load must be used on site. The natural gas usage in Area 5 is primarily for central space heating and domestic hot water. Analysis of the current base case, fuel cell, and PAA is presented in Table 18.

Table 18. Area 5 Fuel Cell Analysis

Base Case Area 5	
Natural Gas Use (MBtu)	42,316
Natural Gas Price ($/MBtu)	$10.35
Natural Gas Cost ($/yr)	$437,972
Fuel Cell Electrical Energy (kWh)/yr	11,531,100

[46] FuelCell Energy LLC. *Direct FuelCell Application Guide.* DFC3000. (2.8 MW) Direct FuelCell Power Plant Application Guide, Revision: B; December 2008.

Current Electrical Price ($/kWh)	$0.13
Current Electrical Energy Cost ($/yr)	$1,499,043
Total Cost	**$ 1,937,015**

Fuel Cell Analysis	
Fuel Cell Size (kW)	1,400
Capacity Factor	95%
Heat Rate, LHV (Btu/kWh)	7,260
Fuel Cell Elec. Eff.	47%
Natural Gas Load (MBtu)	83,716
MBtu converted to electric	39,346
kWh Produced	11,531,776
Thermal Energy Available (MBtu)	18,446 to 36,925
Total Efficiency	**69% to 91%**

PPA Analysis	
Electrical Energy (kWh/yr)	11,531,100
Electrical Energy Price ($/kWh)	$0.13
Annual Electrical Energy Cost	$1,499,043
Heat Usage Estimate (MBtu)	32,767
Heat Value ($ per MBtu)	$10.35
Total Heat Value ($)	$339,136
Annual Electrical Energy Cost Savings	$0
Annual Natural Gas Cost Savings	$339,136
Total Annual Cost Savings	**$339,136**

This analysis shows that the fuel cell provides no electrical energy cost savings, as the PPA price is the same as current electrical energy price paid by the base. However, depending on the agreed upon electrical rate increase in the PPA deal, and the change in NAVFAC's electrical rates future electrical cost, savings could be achieved. The financial justification for pursuing the fuel-cell deal comes from the fact that it provides no-cost thermal energy. The PPA structure of the deal provides immediate cost savings of approximately $339,000 annually in natural gas costs. Additionally, the operations and maintenance costs of the fuel cell are covered by the PPA provider. The total amount of natural gas displaced by the fuel cell was estimated at 32,767 MBtu. The following assumptions were used to estimate this load:

- For building 5500, assumed high quality heat at 150°F is 80% of the natural gas load for this building and building heating with a heat pump is 20% at 100°F.

- For buildings 5532 to 5538, NREL used gas consumption from building 5640 and assumed this buildings is 65% water heating at 120°F, and 35% fan coils at 130°F.
- For all other loads we assumed that water heating is 65% of the load at 120°F and space heating is 35% of the load at 100°F.

This analysis does not include the costs of upgrading the central heat and water distribution network in Area 5 to use the waste heat from the fuel cell. This network was reported to be leaking and in need of upgrading regardless of whether the fuel cell was installed or not. The base already has approximately $4 million in funding available to upgrade this system. It is recommended that the base ensure that the system upgrade includes the ability to use a central CHP system.

The office space in Area 8 has a slightly smaller thermal load than area 5 that is used for space and water heating. However, this area has a large cooling load that could use the heat from the fuel cell in conjunction with an absorption chiller to provide space cooling. The adsorption chiller was assumed to use fuel cell heat at 250°F. It was also assumed that the aging steam system in this area was retrofitted and that heat pumps would be installed to connect the heating system and use the recovery heat from the fuel cells. The additional cost for upgrading these systems is unknown and was not included in this analysis.

Analysis was performed for area 8 with the following assumptions:

- Assumed that fuel cell heat would be used only by the following facilities 8402, 8456, 8473, 8474, 8475, 8656, and 8657. Other area 8 buildings and the nearby hangars were not included.
- Assumed heat-pumps would be installed to use fuel cell heat to provide space cooling.
- Assumed that fuel cell heat recovery use breakdown was 65% for domestic hot water and 35% for heat pumps at 120°F and 100°F respectively.
- Assumed that an absorption chiller will be used to provide cooling with a temperature input of 250°F heat.[47]

Assumed that the coefficient of performance (COP) of this chiller was a 1 and thus displaced kWh at a 1:1 ratio (kWh to MBtu).

The total estimated amount of heat recovered with the above assumptions was 21,046 MBtu. A similar cost analysis to that shown for area 5 above was performed for area 8. The fuel would provide a thermal energy cost savings of $217,000 annually. This analysis assumes that both fuel cells would be eligible for full incentives from the SGIP. For both fuel cells to be eligible for the full incentives, they would need to be technically located on separate utility meters and "customer premises."[48] If the base was not able to take advantage of the full incentive for both fuel cells, the PPA price would likely increase because the third party provider would be eligible for only approximately $7.65 million in incentives rather than approximately $10.8 million in incentives. In

[47] Hot Water Driven Vapor Absorption Machine. Thermax. (Specifications for the Trane ProChill Hot Water absorption chiller were examined and the hot water inlet temperature range is between 158°F and 230°F. The 250°F is a www.trane.com/CPS/uploads/userfiles/chillers/absorption/hotwater_drivenabsorptionchillers.pdf. Accessed April 2010.
[48] "Customer premises" as defined by the California Public Utilities Code Section 2827 and the Small Generation Incentive Program.

this case, the base will need to contact the PPA provider for a new price estimate for area 8. However, it is likely that a financially viable deal could be achieved in this scenario.

Fuel Cell Recommendation: Miramar has two areas available for larger scale CHP solutions with natural gas loads between 21,000 MBtu and 43,000 MBtu annually. NREL recommends that Miramar take advantage the generous California SGIP by installing two renewably powered 1.4 MW fuel cell CHP systems in areas 5 and 8.

5.4.4 Biomass

Technology Overview. Several technologies are available to convert biomass feedstocks into heat and electricity. The most common are combustion, gasification, and anaerobic digestion. Combustion is the direct burning of a feedstock such as wood waste with air to produce steam that can be used for both heat and power. Gasification consists of heating feed material to initiate decomposition reactions and produce a fuel gas, called synthesis gas or producer gas. The gas can then be burned in a heat-recovery steam generator (HRSG) to produce steam for the steam turbine. Emerging applications can use producer gas directly in a reciprocating engine or gas turbine for power generation and heat recovery. Anaerobic digestion is the conversion of wet feedstocks, such as confined animal waste to methane fuel.

Typically, in order for a biomass CHP system to be cost-effective, a plant size of greater than approximately 10 MW is needed. There are many smaller biomass systems in use however, they typically provide only thermal energy and not electrical energy. Miramar does not have large enough thermal or electrical loads to support a large scale biomass project. However, the thermal loads for a small-scale biomass cogeneration system do exist in base areas 5 and 8. The system size for these areas would be between 1 MW and 2 MW of electrical energy generation and produce 10 MBtu to 20 MBtu of energy per hour. Small-scale cogeneration biomass systems of this size are considered to be in a pre-commercial phase. The technology has been demonstrated in several pilot projects, but is not widely commercially available.

Using the REO tool, NREL analyzed the potential for thermal-only and biomass cogeneration systems at Miramar. REO recommended the use of a biomass energy cogeneration system in several scenarios. The size of the biomass system recommended by REO varied, depending on the constraints placed on each analysis (see Appendix B for system sizes).

A Biomass CHP system would consist of a thermal gasification unit that would heat the wood chips with a small amount of oxygen to create a producer gas comprised of carbon dioxide, hydrogen, and methane. This gas would then be combusted in a turbine to produce heat and electricity. The heat could be used to displace natural gas for thermal loads such as water and building heating. The electrical energy generated would displace grid-purchased electricity. Burning the fuel gas to produce thermal energy is a common and commercially viable technology. However, the use of the gas to generate electricity at this scale, it is considered to be in a pre-commercial phase.

Resource Potential

GIS Screening. One of the key attributes to determining the possibility of a biomass project at Miramar is the availability of a biomass feedstock resource. NREL conducted a GIS information screen to access the potential for biomass related projects at Miramar.[49] Table 19 shows the

[49] Landfill resource potential from the GIS screen was adjusted to coincide with the known data from the landfill at Miramar.

approximate resource potential. The largest potential feedstocks for Miramar are urban wood waste at 278,928 tons per year and municipal solid waste, at 1,100,000 tons per year.

Table 19. Miramar Biomass Resource Potential (tons per year within 50 miles)

Crops	Manure	Forest	PrimMill	SecMill	Urban	Landfill	DWWT[50]	Total
1,603	2,366	-	-	16,746	278,928	1,100,000	4,025	1,403,668

NREL used this data to access the potential for biomass related energy projects at Miramar in REO.

Miramar Greenery. The most promising feedstock for a biomass project at Miramar appears to be wood chips produced at the Miramar Greenery located on the base premises at the Miramar landfill. The Miramar greenery processes organic waste diverted from the landfill along with yard trimmings and other biomass sources into compost, mulch, and wood chips available for sale to the general public. The facility currently processes 100,000 tons per year and is planning an expansion to 150,000 tons per year.[51] The wood chips have a moisture content of approximately 20%. When dry, they have a heating value of 8,000 Btu/lb and less than 1% ash content. Currently, these wood chips are being sold to the general public at $10 per cubic yard. Wood chips have a bulk density between 300 and 800 pounds per cubic yard depending on the type of wood, water content, bark, impurities (like soil), and other factors. Assuming an average density of 500 lbs per cubic yard, one ton of wood chips would cost approximately $40 without any type of bulk discount and excluding transport cost.

Thermal-only System. A small-scale thermal-only biomass system could be used at Miramar to provide space and water heating to displace natural gas loads. These systems are commercially available in a size range suitable to Miramar's central loads in area 5 or 8.

Biomass could potentially be a cheaper heating fuel for the base than natural gas. Assuming that each pound of biomass had a heating value of 8,000 Btu/lb, the wood chips would have an approximate heating value of 16 MBtu per ton. At a price of $50 per ton, wood chips would cost $3.13 per MBtu. This is significantly less than the $10 to $25 per MBtu than the base has historically paid for natural gas. However, the efficiency of a gasification system or boiler to produce energy from wood chips would be lower than that of natural gas system. Additionally, a biomass system would have increased operations and maintenance costs. Analysis of a thermal gasification system is presented in Table 20. System economics depend largely on the price difference between natural gas and wood chips. For a thermal-only system sized to slightly below the total thermal load of base area 5, at a natural gas price of $10.35 per MBtu and $50 per ton for wood chips, the payback is negative, as shown in Table 20.

Table 20. Thermal-only System

Biomass Gasifier Size (MBtu/hr)	5.0
Biomass Gasifier SynGas Delivery (MBtu/yr)	37,230
Biomass Natural Gas Savings (MBtu/yr)	37,230

[50] Domestic Waste Water Treatment
[51] City of San Diego Environmental Services Department. Non Disposal Facility Element. September 2008, www.sandiego.gov/environmental-services/geninfo/pdf/draftnondisfacelement.pdf. Accessed April 2010.

Biomass Gasifier Annual Utility Cost Savings ($/yr)	$385,331
Tons of Fuel Used	4,964
Per Ton Fuel Cost ($/ton)	$50.00
Fuel Cost ($)	$248,200
Biomass Gasifier Cost	$2,340,000
Biomass Gasifier O&M Cost ($/yr)	$287,590
Biomass Gasifier Payback Period (yrs)	Negative

A sensitivity analysis was performed to determine the payback at several different natural gas prices, for a fixed price of $50 per ton for wood chips. This is shown in Table 21.

Table 21. Sensitivity Analysis

Natural Gas Price ($ per MBtu)	Payback (Yrs)
$10	negative
$12.50	negative
$15.00	103
$17.50	20
$20.00	11
$22.50	8

At high natural gas prices, a thermal-only system has a positive payback. However, the current natural gas price at the base is closer to $10 per MBtu and would provide a negative payback. At a natural gas price of $10 per MBtu wood chips would need to cost less than $15 per ton for a system to be cost-effective. Regardless of these prices, the payback for a CHP system would likely be even greater than a thermal-only system, but would pose more technology risk. The thermal-only system does have the advantage of being more commercially available at the size needed for Miramar than CHP systems.

Biomass Powered Cogeneration. NREL examined the potential for a thermal gasification biomass CHP system. These systems are typically sized based on the minimum thermal load for a building for series of buildings. The system analyzed would displace approximately 37,000 MBtu of natural gas annually or 88% of the load of base area 5. The results from the REO analysis are shown in Table 22.

Table 22. Biomass Cogeneration Scenario

Biomass Gasifier Size (MBtu/hr)	10
Biomass Gasifier Cogen Size (kW)	1,100
Biomass Gasifier SynGas Delivery (MBtu/yr)	74,460
Biomass Natural Gas Savings (MBtu/yr)	37,528
Biomass Gasifier Annual Utility Cost Savings ($/yr)	$1,680,333
Tons of Fuel Used	9,928
per ton fuel cost ($/ton)	$50.00
Fuel Cost ($)	$496,400

Biomass Gasifier Cost	$6,613,360
Biomass Gasifier O&M Cost ($/yr)	$872,180
Production Incentive ($/yr)	$0
Biomass Gasifier Payback Period (yrs)	21

The analysis above shows a positive system payback after 21 years. However, this analysis should be treated as a rough estimate because this is an evolving and not yet mature technology. There is potential for the base to receive a production incentive for this system of up to $0.093 per kWh. If this incentive was obtained, the payback for this system would drop to approximately seven years. Eligibility for this incentive program would depend on whether the base or a third party owned the system. Further analysis of available incentives is recommended if the base should desire to pursue a biomass system.

Fuel Cost. The other key variable for the feasibility of a biomass project at Miramar is fuel cost. A sensitivity analysis was conducted between fuel cost and economic payback for the scenario above in which a biomass project displaces approximately 37,000 MBtu, but does not qualify for any incentive programs.

Table 23. Payback at Various Biomass Fuel Costs

Biomass Cost ($ ton)	Payback
$15	10
$30	13
$45	18
$60	31
$75	104
$ 90	negative
$105	negative

This analysis illustrates that the feasibility of a biomass energy system is quite sensitive to fuel costs. Under this scenario, if fuel costs are above about $75 per ton, then the system payback is negative. If Miramar Marine Air Station is able to negotiate a long-term supply agreement with the Miramar Greenery (which is operated by the City of San Diego), at a fuel cost below $50 per ton, then it should consider a biomass energy system.

Recommendation: NREL analysis shows that the resource potential for a biomass project at Miramar is moderate, with the exception of a highly promising fuel source located in the Miramar Greenery. NREL recommends exploring the possibility of a long term supply agreement with the Miramar Greenery for the procurement of wood chips to be used as fuel in a biomass project in the future. If an agreement can be reached with favorable economics, Miramar should contact the manufactures of biomass cogeneration technology to determine its current feasibility and costs.

Overall CHP Recommendation: CHP provides a promising opportunity for Miramar to reduce costs, reduce emissions, and increase energy security at the base. The most promising option at this time for large-scale CHP on the base appears to be renewably powered fuel cell in base areas 5 and 8. It is recommended that this option be further pursued. If this option no longer appears feasible, biomass cogeneration or standard cogeneration should be pursued. Additionally it is recommended that the base pursue microturbines for small-scale CHP for buildings without the ability to connect to a centralized system.

5.5 Landfill Gas

Technology Overview. Landfill gas is generated through the anaerobic decomposition of carbon-based waste streams deposited in a landfill. The gas produced is primarily composed of methane and carbon dioxide. Typically, a gas handling system at the landfill traps, collects, and transports the gas produced. The gas produced will often need to be cleaned up before combustion to remove potentially hazardous compounds such as sulfur. Once a landfill is capped and closed off, it will continue to produce gas for 15 to 20 years.

Planned Projects. The landfill area is located south of the Main Base and is designated in Figure 47 as AI, AJ, AK. Area AI has been capped off for the production of methane. A portion of the methane is delivered to a nearby water treatment plant for use in steam and electricity. Some of the methane is being used to run a turbine onsite to produce 10 MW of electricity. Area AJ of the landfill is currently being capped off to produce additional methane. This methane will be used to generate an additional 3 MW that will be used by Miramar. Miramar will be installing a transmission line to tie into their existing distribution system. The expected cumulative energy from the Land Fill gas project is estimated to be 25,000kWh/yr. This assumed a 95% capacity factor.

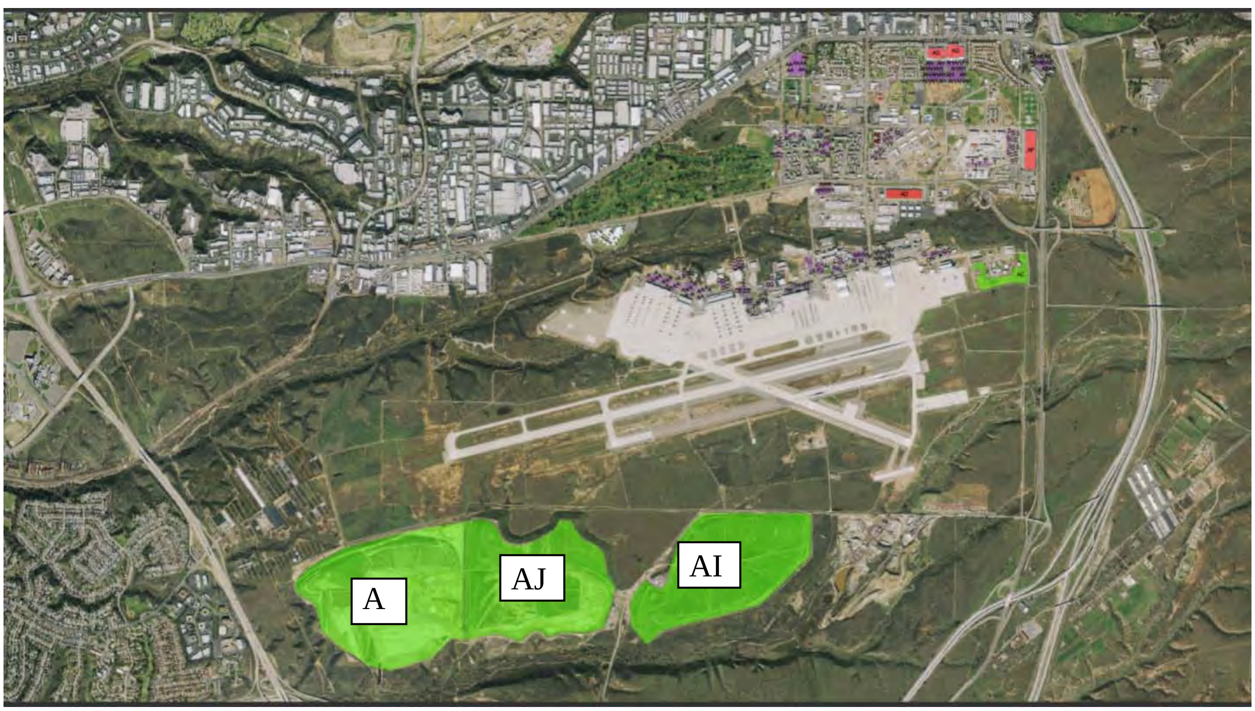

Figure 47. Landfill area AI, AJ and AK (Image courtesy of MCAS Miramar, modified using NREL's GIS Tools)

Additional Analysis*:* The only landfill managed by the City of San Diego is located at the Miramar Marine Air Station. The landfill area is owned by Miramar and leased to the City. More than 1.1 million tons of waste is disposed of at the landfill annually.[52] At the current rate of disposal, the landfill will likely be filled to capacity and have to close by 2017. All cities in California are

[52] The City of San Diego. Miramar Landfill, www.sandiego.gov/environmental-services/miramar/. Accessed April 2010.

required to reduce, reuse, or recycle half of their waste or be subjected to a $10,000 per day fine. In 2006, the City of San Diego met this requirement with a 55% diversion rate. The opportunity exists to divert municipal solid waste from the landfill and use it for energy generation. However, the potential to directly use waste from the landfill for combustion, digestion, or gasification would be difficult for Miramar. The average size of a typical waste-to-energy facility is larger than the load requirements of Miramar. However, there are several systems in a pre-commercial phase that could allow for a smaller waste-to-energy project. A successful project would require a large amount of coordination and cooperation between the base and the City of San Diego that operates the landfill. Financial justification for a waste-to-energy project using just the waste generated on base might be difficult because, as part of its deal with the City of San Diego, the costs for the base to dispose of its own waste in the landfill are reduced. Additionally, a project would have to compete with the existing uses of the waste sent to the landfill for waste-to-energy projects, as well as mulch, compost, and woodchip production. However, the potential to obtain excess biogas from the landfill presents an interesting opportunity for Miramar. This would require the construction of a biogas pipeline between the Main Base and landfill. The pipeline would allow the base to use biogas to generate both heat and power for the facilities on the Main Base. This would not only reduce the energy footprint of the base, but provide a secure fuel source at a predictable long-term cost.

Recommendation: NREL supports the planned landfill gas PPA. NREL also recommends additional analysis on the potential to obtain biogas from the landfill and use it in the facilities on the Main Base to power boilers and cogeneration systems.

5.6 Photovoltaic Power

Technology Overview: PV panels convert sunlight directly into electricity. They have no moving parts and require very little required maintenance, make no noise, and emit no pollution. They are highly reliable and last 25 years or longer. They may be installed on racks on the ground, mounted on poles, and mounted on rooftops or carports.

Planned Projects: Miramar already has several PV projects in various stages of planning. The details of these projects are listed in Table 24. The total size of the planned PV projects is approximately 2.3 MW and the annual energy production will be about 3,500 MWh/yr. This represents approximately 5% of Miramar's total annual electrical consumption.

Table 24. Miramar's Planned PV Projects

PV Project Location	Project Size (kW)	Project Cost ($)	Implement-ation Year	Project Status	Project Financing	Estimated Electrical Production (MWH)
Carports 6311	200	2,000,000	2010	Under contract	ARRA	298
Carports 6311	300	2,800,000	2010	Expected under contract 11/2009	ECIP	447
Rooftop 6311	30	240,000	2010	Under contract	ECIP	45
Commissary Carports	1000	11,000,000	2011	Pending	ECIP	1489

Rooftop 7209	500	5,000,000	2011	Pending	ECIP	745
Carports 9670	200	2,000,000	2011	Pending	ECIP	298
600 Street lights (220 W each)	132	4,900,000	2009-2011	2 of 7 Under contract	ECIP	198
Total	**2362**	**7,940,000**				**3519**

Analysis: NREL examined the potential to add a large amount of PV to the installation at Miramar. On-site electrical energy generation with a large amount of PV has the potential to make Miramar a net zero electrical installation. The electrical baseline grid-connected load was used as the base case for adding PV to the system. Solar data for 2008 were used. Available area was noted for three types of PV systems: ground mount, roof top, and carports (see Table 25).

The PV systems considered in the grid analysis section have the following components: PV arrays, which convert light energy to DC electricity and Inverters, which convert the DC to alternating current and provide safety, monitoring, and control functions.

Grid-tied systems with net metering and no storage were sized to meet the load.

PV system sizes were calculated using the assumption below for the various system types using PV Watts:

Table 25. PV Systems Energy and Cost

System Type	Annual energy kWh/kW	Installed Cost ($/W)	Energy Density (W/ft^2)
Roof Top Mount 10 Degree Tilt	1414	$6.00	8
Ground Mount 10 Degree Fixed Tilt	1414	$5.00	3.8
Carport, 0 Degree Tilt	1314	$7.50	10

For the analysis, NREL used the micro-power Hybrid Optimization Modeling Tool (HOMER) Version 2.67 beta.

Figure 48 shows the potential PV carport sites (shown in purple), the roof mount (shown in red) and the ground mount (shown in green).

The sites identified in Figure 48 are the PV projects discussed during a tour of the base with the Miramar Energy Team. Some areas were not available for PV installation due to environmental or tactical restrictions. Table 26 presents possible PV locations sizes and costs.

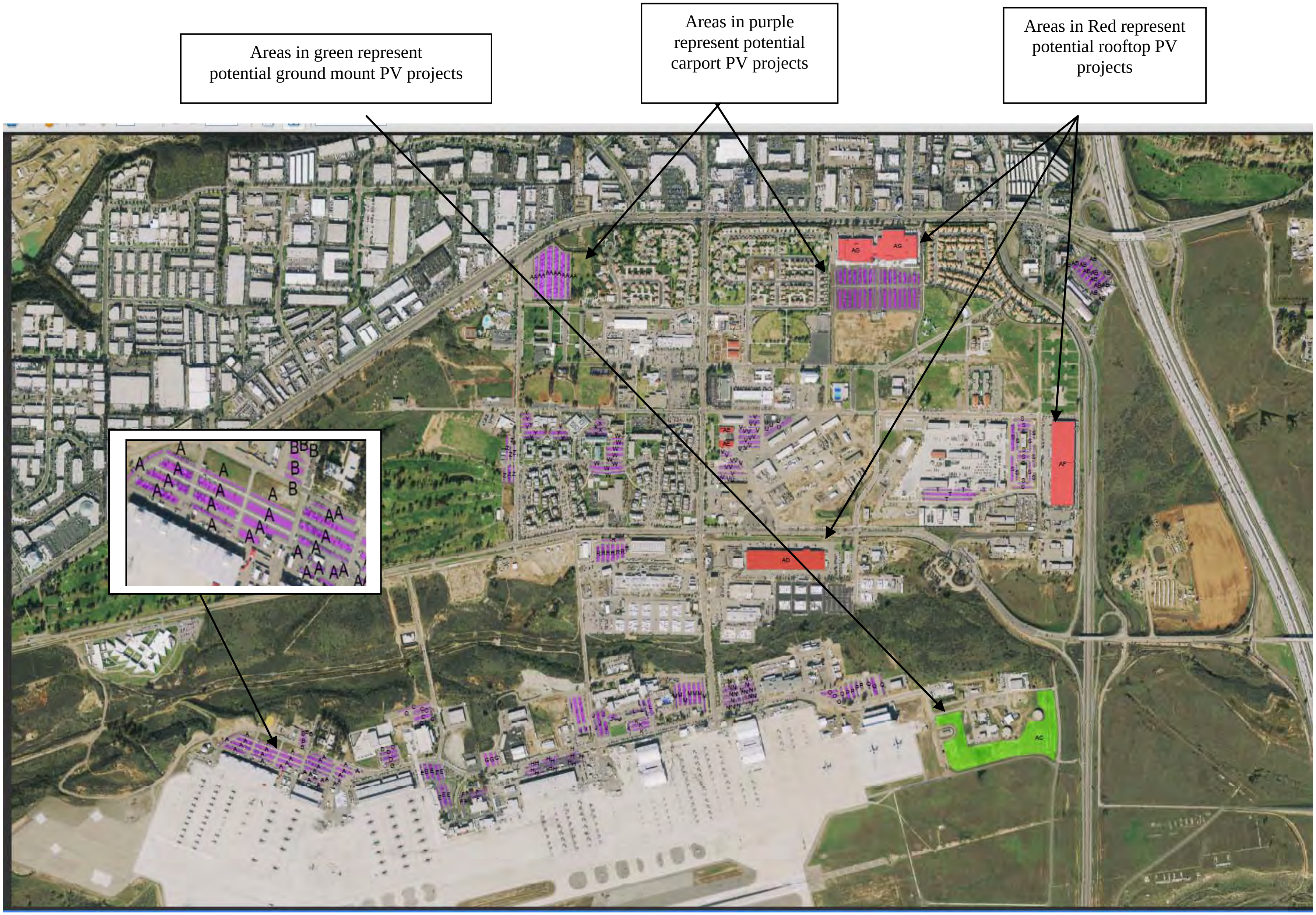

Figure 48. Map of Miramar-proposed PV projects (Image courtesy of MCAS Miramar, modified using NREL's GIS Tools)

Table 26. Potential PV Projects (Location labels are mapped in figures 47 and 48)

Location Area (Bld)	Array Tilt (Deg)	Potential Area (ft^2)	Max Usable Area (ft^2)	PV System Size (kW)	Annual Output (kWh/year)	Annual Cost Savings ($/year)	Annual O&M ($/year)	System Cost with No Incentives ($)
Roof mounted								
Buildings (Rooftop PV)								
AD (7209)	10	197,437	157,950	1,264	1,786,729	268,009	12,889	7,581,595
AE (6311)	10	24,159	19,327	155	218,632	32,795	1,577	927,716
AF (6001)	10	255,726	204,581	1,637	2,314,217	347,132	16,694	9,819,873
AG (2660 & 2661)	10	251,757	201,406	1,611	2,278,303	341,746	16,435	9,667,483
Totals		**729,080**	**583,264**	**4,666**	**6,597,881**	**989,682**	**47,594**	**27,996,666**
Ground mount (1 Axis Tracking)								
Ground Mount (fixed)- AC	10	495,406	445,866	1,706	2,412,206	361,831	29,854	8,529,723
Landfill: AI	10	8,945,649	8,051,084	30,805	43,557,671	6,533,651	539,080	154,022,882
Landfill: AJ	10	9,155,509	8,239,958	31,527	44,579,510	6,686,927	551,727	157,636,174
Landfill: AK	10	11,313,759	10,182,383	38,959	55,088,344	8,263,252	681,786	194,796,126
Totals		**29,910,323**	**26,919,291**	**102,997**	**145,637,731**	**21,845,660**	**1,802,447**	**514,984,905**
Carport PV								
A (9570 & 9670)	0	150,529	150,529	1,505	1,977,956	296,693	19,192	11,289,703
AA (RV Storage)	0	155,102	155,102	1,551	2,038,037	305,705	19,775	11,632,629
AB (19315)	0	59,904	59,904	599	787,133	118,070	7,638	4,492,768
AH (2660 & 2661)	0	229,825	229,825	2,298	3,019,897	452,984	29,303	17,236,853
B (8630)	0	9,649	9,649	96	126,782	19,017	1,230	723,642
C (8671)	0	27,736	27,736	277	364,452	54,668	3,536	2,080,204
D (8672)	0	19,499	19,499	195	256,219	38,433	2,486	1,462,440
E (9470)	0	45,711	45,711	457	600,641	90,096	5,828	3,428,316
F(8380)	0	11,706	11,706	117	153,811	23,072	1,492	877,914
G (9175)	0	15,420	15,420	154	202,617	30,393	1,966	1,156,489
H (9500)	0	36,661	36,661	367	481,731	72,260	4,674	2,749,606
I (8600)	0	32,906	32,906	329	432,387	64,858	4,196	2,467,965
J(8402)	0	29,459	29,459	295	387,091	58,064	3,756	2,209,422
K(8402)	0	16,707	16,707	167	219,530	32,929	2,130	1,253,024
L(8402)	0	15,456	15,456	155	203,095	30,464	1,971	1,159,217
M (8473)	0	56,861	56,861	569	747,154	112,073	7,250	4,264,580
N (8461)	0	47,545	47,545	475	624,740	93,711	6,062	3,565,868
O (8116)	0	15,260	15,260	153	200,520	30,078	1,946	1,144,522
P(8116)	0	17,090	17,090	171	224,567	33,685	2,179	1,281,778
Q(8116)	0	16,389	16,389	164	215,348	32,302	2,090	1,229,158
R (7133)	0	47,448	47,448	474	623,463	93,519	6,050	3,558,578
S (6001, 6003, 6004)	0	70,664	70,664	707	928,526	139,279	9,010	5,299,804
T(6006, 6007, 6008)	0	44,476	44,476	445	584,416	87,662	5,671	3,335,710
U (6274, 6275)	0	17,380	17,380	174	228,376	34,256	2,216	1,303,514
V (6311)	0	75,040	75,040	750	986,032	147,905	9,568	5,628,037
W (5439, 5640)	0	49,391	49,391	494	648,995	97,349	6,297	3,704,310
X(5500)	0	16,185	16,185	162	212,669	31,900	2,064	1,213,864
Y (5509)	0	37,860	37,860	379	497,485	74,623	4,827	2,839,525
Z (Golf Club)	0	26,829	26,829	268	352,539	52,881	3,421	2,012,206
Totals		**1,394,689**	**1,394,689**	**13,947**	**18,326,208**	**2,748,931**	**177,823**	**104,601,644**

Table 26 lists the calculations for PV size, production, and cost for all possible sites. The table data shows that it would be possible to place approximately 20 MW of PV on the building rooftops, carports, and available ground mount areas. Using this table, NREL conducted additional analysis with the Hybrid Optimization Model tool, HOMER.

Additional PV HOMER Analysis: The total PV system size from all sites on base, excluding the landfill area is approximately 20,319 kW. Using HOMER simulation and the actual solar resource data for 2008, the PV energy production is 32,817,752 kWh/yr, providing 49.3% of the total electrical load. The grid purchase is estimated at 41,320,488 kWh/yr and grid sale for net-metering is approximately 7,594,830 kWh/yr.

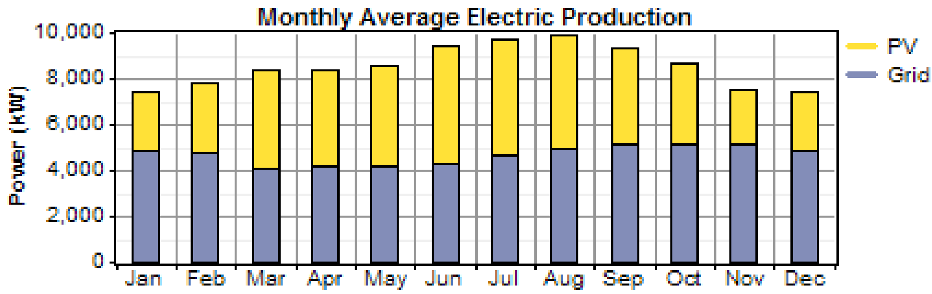

Figure 49. Potential PV projects meet 49.3% of load

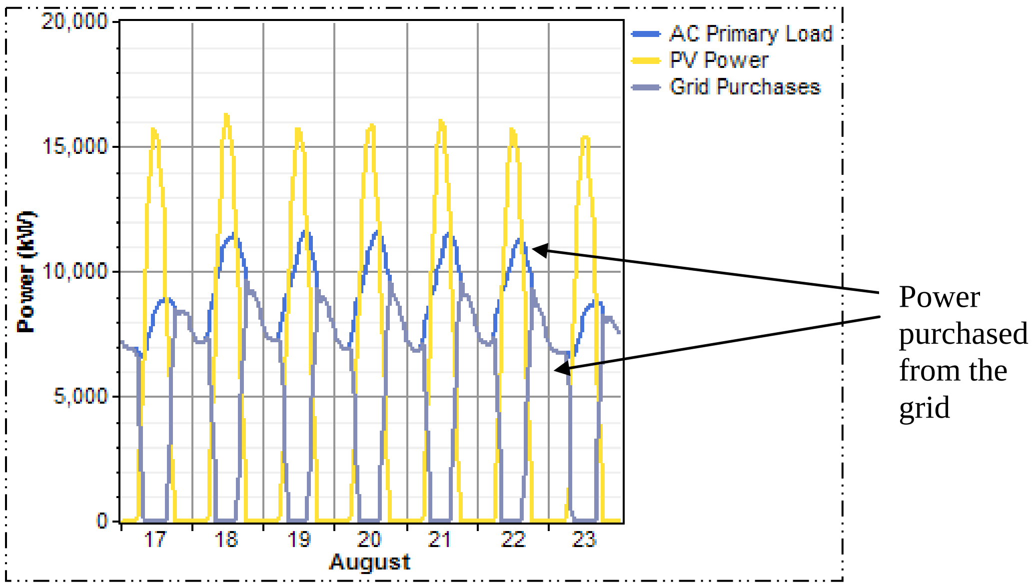

Figure 50. August grid purchase savings

Possible PV on Land Fill Area: Miramar plans to purchase 3 MW of power annually from the landfill gas plant in operation. Once the areas of the landfill are capped off for methane production, the top ground can be used for PV installations. Available land was noted in three parcels (see Figure 47):

- Section AI: 8,945,649 ft^2 (831,500 m2 or 205 acres)
- Section AJ: 9,155,509 ft^2 (851,000 m2 or 210 acres)
- Section AK: 11,313,759 ft^2 (1,052,000 m2 or 260 acres)

Sections AJ and AK are available for solar installations provided by Miramar (NREL understands that the area AI is not technically Miramar's land to develop). The landfill area calculations for PV are provided in Table 26. The total calculated area from AJ and AK could accommodate a 70,485 kW PV array. A cost analysis is done in section 5.7 to compare the Levelized Cost of Electricity (LCOE) of PV and CSP on this landfill area.

Recommendation: A site visit to Miramar and discussions with the Miramar Energy Team revealed a number of potential sites for PV installation. These areas were mapped out for PV project on rooftops, ground mount, and carports (Figure 48). Some of the areas were not available for PV installation due to environmental protection or tactical restriction. The total potential projects that could be installed on the base are listed in Table 26. Excluding the landfill area for ground-mounted PV, the total potential PV projects for Miramar could amount to 20.3 MW of power, producing 32,818 MWh/yr of energy. The PV projects would allow 49% of Miramar's total electrical load to be met with solar energy. However, the estimated cost for installing this amount of PV before incentives are applied is $141 million. At an electrical power displacement price of $0.13 per kWh, a total annual savings would be $4.3 million. Annual operations and maintenance costs would be about $250,000 per year. Thus total savings would be about $4 million per year. The simple payback for this scenario would be about 35 years. If the systems were owned by a third party able to take advantage of the investment tax credit, this payback would drop to about 25 years. If Miramar wanted to achieve net zero electrical energy status, it could do so by installing a large amount of PV. However, the large capital cost for the PV systems and the long payback period make installing 20.3 MW of PV a sub optimal energy solution for the base. NREL recommends that the base use this analysis to install as much PV as possible in conjunction with the new ESPC contract or through PPAs. However, if a PV system size on the order of 20 MW is desired at the base, it would be best to wait until the landfill area is available for development because the costs for a large-scale ground-mounted system there would be cheaper than the large number of carport and rooftop systems presented in this analysis.

5.7 Concentrating Solar Power

Technology Overview: Electricity and steam can be produced through a solar thermal process using CSP. The most common power production technologies are dish sterling engines and parabolic troughs. Collectors focus solar heat onto a fluid and the heat creates steam, which turns a turbine or engine attached to a generator to create electricity. Motors and controls track the sun. Although the systems have minimal moving parts, they do require preventative and unscheduled maintenance. Solar thermal plants can range in size from 1 MW to 1000 MW, and generally require 5 to 10 acres of land per MW.

Planned Project: Miramar is planning a CSP demonstration project. The base will purchase four 25 kW sterling engine CSP dishes. The estimated cost for the system is $1.5 million. The project will be funded by Energy Conservation Investment Program (ECIP) and implemented in 2011. Assuming a 19% capacity factor for the system, the energy production would be approximately 163 MWh per year. The project is planned to be located near the base's west gate.

CSP Analysis: NREL used the Solar Advisory Model (SAM) to analyze the potential for a large CSP project at Miramar on the capped landfill in areas AJ or AK in Figure 47. However, this area will not be available for development for several years. Examination of the Load Curve for Miramar suggested that a 10 MW CSP system would meet approximately 92% of the load on an hourly basis (See Appendix I for load curve and analysis details). The CSP analysis examined four different technology configurations:

- Dish/Sterling engine (no storage)
- North-south oriented parabolic troughs with no storage
- North-south oriented parabolic troughs with storage
- East-west oriented parabolic troughs with storage

Potential process steam needs at Miramar that could be met using CSP-produced steam were unclear. Several factors will affect the potential to use steam generated by a CSP plant at Miramar. First, the proposed location for a large scale CSP plant is on the capped landfill. This site is approximately five miles from the majority of base facilities. This distance would require additional infrastructure and increased costs to use steam or hot water produced on the landfill on the Main Base. The potential use of process steam is further complicated by the fact that the base primarily uses individual space and water heating systems for most facilities and not a large centralized plant that would be most conducive to using steam from a CSP plant. There are several facilities located on the landfill that might be able to use this waste heat. Further analysis is recommended to determine the heat loads of these facilities. A steam load of 5,110,000 Btu/hr (1.5 MW) was used for this analysis. However, a significant amount of additional steam would be available for use in nearby facilities or on the Main Base.

Dish/Engine CSP. Consultation with Chuck Andraka of Sandia National Labs indicated that a 10 MW system size is smaller than dish/engine system developer Stirling Energy Systems (SES) believes to be cost-effective for deployment. SES recently announced a contract for a 27 MW system in Texas. Infinia produces smaller dish/engine sets and may be a more suitable vendor for this scale. Nonetheless, an SES design was modeled because this is the system model available within SAM. While performance can be predicted using the SAM code, cost data for dish/engine systems are not well known and a contact with a vendor is recommended. Dish/engine systems do not incorporate thermal energy storage (TES) and do not require cooling water. The 10 MW system consists of 400 25 kW dishes.

Parabolic Trough CSP. Trough systems are the most mature CSP technology and cost information is relatively well known. Traditionally, troughs are oriented along a north-south axis because this layout generates the greatest amount of energy over the course of a year. However, such a layout exhibits large variation between summer and winter average daily energy output. If less seasonal variation or high capacity factors are desired, an east-west orientation may be preferred.

Parabolic trough plants can incorporate thermal energy storage (TES) by storing the heat transfer fluid or a dedicated thermal storage fluid at high temperature for later use. For this analysis, trough plants with TES configurations were assumed for both north-south and east-west field orientations. The TES was assumed to be a two-tank molten salt design, similar to that running at the 50 MW Andasol-1 plant in Spain. The field and TES size were selected to minimize LCOE and avoid energy dumping. Storage was also capped at 18 hours full-load capacity to avoid excessive pumping losses for the large solar field. The four different CSP configurations are outlined in Table 27.

Table 27. CSP Plant Assumptions and the Resulting Costs

Parameter	Case 1 10 MWe Dish/Engine	Case 2 10 MWe Trough w/o TES	Case 3 10 MWe Trough 12-hr TES	Case 4 10 MWe Trough 15-hr TES
Solar Field Aperture (m2)	35,000	75,000	150,000	224,000
Plant Footprint (acres)	25	65	120	180
Orientation	--	North-South	North-South	East-West
Annual Power Gen (MWh)	16,300	21,400	42,200	56,800
Annual Capacity Factor	19%	24%	48%	65%
LCOE (nominal)[1]	n/a[2]	$0.23/kWh	$0.24/kWh	$0.25/kWh
Est. installed Cost	n/a[2]	$57M	$126M	$183M
Thermal Storage (hrs)	0	0	12 (352 MWh-t)	18 (528 MWh-t)

[1] Assumes 30% investment tax credit.
[2] Accurate estimate not available, vendor quotes are recommended.

Considerations: Below is a list of considerations for the implementation of CSP:

- While the dish/engine system is modular, system vendor SES is targeting larger scale installations. Dish/engine systems do not incorporate energy storage, so a cost comparison to PV would be needed to assess their viability.
- A trough system with 18 hours of storage can approximately match the average daily load throughout the year. East-west oriented troughs are a better match to the seasonal load variations.
- California utility time-of-delivery rates reward summer peak energy delivery. This favors north-south oriented troughs.
- Hourly solar data for the same load period are needed to perform a day-to-day or hour-by-hour assessment of CSP output to load. Although the average daily output can be made to match closely to average daily load, there are time periods when output from the CSP plant will be zero.
- The trough CSP systems would be able to provide steam either as waste heat or from a thermal storage well in excess of the modeled demand of 1.5 MW.

All the examined CSP systems fit within the allotted space designated as AJ or AK. The trough systems will require relatively flat land; the dish/engine systems can tolerate sloped land.

Recommendation: The landfill area at Miramar is not currently available for large-scale CSP development. When the area is available in several years, NREL recommends additional analysis be conducted to determine the feasibility of large scale CSP or PV on that site.

5.8 Government Fleet Fuel Use

Analysis: Miramar fleet fuel consumption is subject to various statutory and Executive Order requirements. Reported fuel use and vehicle inventory data were occasionally inconsistent, but the data reported in Table 27 are believed to be accurate for analysis purposes.

An initial analysis of Miramar's fleet indicates approximately 262 vehicles on site in late 2008. Many of these vehicles are older models (manufactured in the 1980s and 1990s), and Miramar may be able to take advantage of GSA's offer to replace inefficient vehicles with more fuel-efficient vehicles using $300 million of ARRA funding. In some cases, however, GSA will not able to meet the Federal demand for specific vehicle replacements; so some older vehicles may remain in Miramar's fleet.

The term "Miramar's fleet" needs further definition. While there were 262 vehicles on site at MCAS Miramar, they did not belong to a large Miramar fleet. The 262 vehicles were in many smaller fleets, including Comptroller, Fire Department, Navy Supply, Station Property, Food Service, Air Operations and many other small departments and organizations. Combining all these into one large "Miramar fleet" for analytical purposes allows one to take advantage of the synergy of all Miramar-based vehicles.

More than 150 of the 262 vehicles at Miramar appear to travel less than 5,000 miles per year. In some cases, this may be deliberate, but in many cases, this low mileage is likely a result of one of two circumstances: (1) vehicles are not driven frequently; or (2) vehicles are driven frequently, but only for short distances, primarily on base. If vehicles are not driven frequently, Miramar has opportunities to downsize its vehicle inventory. If vehicles are driven frequently but only for short distances, opportunities exist to replace these vehicles with smaller, campus-suited vehicles, similar to NEVs.

NREL observed several NEVs at a fleet facility on Miramar MCAS. These NEVs had been used that morning and were recharging at about noontime. Since peak electrical demand often occurs about noon, acquiring NEVs with a longer battery life and/or charging the NEVs at off-peak electrical load hours would be worth considering.

Over 75% of the vehicles in Miramar's fleet are either gasoline or E85 fueled. NREL understands that as of late 2008, E85 fuel was not available at Miramar, but that efforts were being made to ensure on-base E85 availability. NREL analysts believe there is an opportunity for significant petroleum reduction at Miramar due to E85 use. Many gasoline-fueled vehicles could be replaced by E85 flex fuel vehicles (FFVs), and combined with the current large number of FFVs on base, E85 could represent the majority of fleet fuel use in the future. Using E85 decreases GHG emissions and helps to meet petroleum reduction and alternative fuel use mandates. NREL was advised that on occasion, CNG-fueled vehicles did not have access to CNG fuel due to infrastructure maintenance issues, so replacing CNG-fueled vehicles with E85 vehicles (which are generally less expensive than CNG vehicles) is a possible option as well.

NREL was provided with data indicating that about 75% of diesel fuel use at Miramar was biodiesel fuel. NREL supports this relatively high biodiesel use, but there are a few reservations with biodiesel use at Miramar. The 75% biodiesel use rate is of potential concern because mixing biodiesel fuel and diesel fuel in engines is generally not recommended. Additionally, diesel and biodiesel storage tanks cannot be used interchangeably, and diesel tanks require a thorough cleaning before converting to biodiesel storage tanks. Diesel vehicles at Miramar should use biodiesel fuel consistently, but during conversations with Miramar fleet personnel, they indicated that this was not the case. Additionally, they provided a sample of biodiesel fuel for NREL to examine that was found to be contaminated, and they indicated they had experienced problems with biodiesel fuel in the past.

5.9 Recommendations

Adopt a Miramar vehicle "pool" approach. As mentioned, it appears that there are many sub-fleets at Miramar containing a relatively small number of vehicles. For example, child development, comptroller, counselor, dental, postal, chaplain and several other entities had a single vehicle assigned to them, and many other small fleets had two or three vehicles in their individual fleets. It is likely that many of these organizations do not need a vehicle assigned to them full time, and those with more than one vehicle assigned to them do not need as many vehicles assigned to them as are currently assigned. Having a pool of vehicles available for use available for all entities at Miramar could solve this challenge. For example, one solution may be replacing 10 vehicles assigned to 10 separate organizations at Miramar with six vehicles that could be accessed by all 10 organizations. The fact that roughly 60% of Miramar's vehicles travel less than 5,000 miles per year makes it clear that vehicles are not being over-used and that there are opportunities for combining vehicle use through a pool approach.

Transform Miramar's vehicle inventory. Miramar's vehicle inventory should be transformed by "rightsizing" the overall fleet and ensuring that the fleet contains the right type of vehicles. "Rightsizing" can be accomplished by adopting the pool approach described above, and includes eliminating excess vehicles. Eliminating most of the approximately 60 vehicles that are driven less than 200 miles per month is a good starting point. Additionally, NREL recommends that Miramar look for opportunities to transform fleet composition. This involves considerations such as whether a pickup truck is necessary for a mission, and if so, whether it must be a 4x4 pickup, or if a two-wheel drive is sufficient. When a pickup truck is necessary, an E85 FFV could be a good option. Similar logic could be applied to every vehicle in Miramar's fleet. Questions to ask include:

- Is the vehicle required? If the vehicle is a low mileage vehicle, consider eliminating it in favor of a pool approach.
- If the vehicle is required, can it be a NEV or some other type of smaller electric vehicle?
- If a NEV is not acceptable, can the vehicle be a small fuel-efficient AFV?
- If the vehicle cannot use alternative fuel, could it be a hybrid electric vehicle (HEV)?
- If the vehicle cannot use alternative fuel or be a HEV, can it be a diesel vehicle using biodiesel fuel?

In short, NREL believes it is possible for Miramar's overall fleet to be transformed to one that uses E85, CNG, biodiesel, and/or electric fuel exclusively. Older NEVs with batteries requiring mid-day recharging should be replaced by NEVs that can operate all day on a charge from the previous night during low electrical demand timeframes. If fueling CNG vehicles continues to be a challenge, consider replacing CNG vehicles with FFVs. The incremental cost of FFVs is frequently much less compared to CNG vehicles. Replacing older, less fuel-efficient gasoline-fueled vehicles with efficient leased vehicles from GSA over a period of time is also a good strategy to consider.

Use alternative fuel. Once E85 infrastructure is established at Miramar, fleet managers should require that E85 be used in all FFVs. This action, combined with replacing many gasoline-fueled vehicles with FFVs will displace most of the petroleum used in Miramar fleets. It is recommended that Miramar fully commit to biodiesel use 100% of the time. Mixing diesel fuel and biodiesel fuel in engines and storage tanks will have adverse affects on diesel vehicle performance. If Miramar experiences poor results using biodiesel, it should consider switching fuel suppliers. Existing biodiesel specifications guarantee a certain quality of biodiesel fuel, and the Marine Corps has had great success with biodiesel fuel. Diesel vehicles at Miramar should perform as well with biodiesel fuel as they would with diesel fuel.

Just over half of Miramar's vehicle fleet fuel use in 2008 was gasoline. Assuming for the short term that Miramar is able to replace half their gasoline-fueled vehicles with E85 vehicles, and that all E85-capable vehicles use E85 exclusively, Miramar has the potential to displace over 67,000 gallons of gasoline. Using biodiesel exclusively in diesel vehicles would displace another 2,000 gallons of petroleum, for a total of nearly 70,000 gallons of petroleum use avoided. Although this number in itself is not large, it is important because of the relative amount of potential alternative fuel use at Miramar. With the assumptions above, alternative fuel use would comprise nearly 70% of all vehicle fuel use at Miramar, compared to the entire Federal fleet's use of alternative fuels in 2008, which was less than 4% their total fuel use.

Update: A conversation with Miramar personnel in November 2009 indicated that Miramar was in the process of converting some gasoline tanks to E85 tanks. Once complete, large increases in E85 use are expected.

5.10 Additional Strategies to Reduce Load and Footprint

Purchase Renewable Energy Certificates (RECs). Purchasing offsets or credits could allow Miramar to achieve a 100% renewably powered status. Since the base is unlikely to be able to achieve a 100% reduction through energy projects alone, REC purchases are an alternative strategy. For example, tactical fuel use is essential to the mission at Miramar and cannot be eliminated. The purchase of RECs or carbon credits could offset tactical fuel use and help Miramar reduce its overall environmental impact. However, Miramar could not become a NZEI through the purchase of RECs, as the net zero concept is based on the use of on-site renewable energy generation.

Demand Response. An additional option that Miramar may want to consider for its facilities is undertaking demand response contracts. Demand response is the lowering of electrical load during peak usage. By signing up as a demand-response provider, Miramar would gain additional revenue to fund its energy projects and free advanced metering infrastructure. This should be a particularly viable solution if Miramar has electrical loads that it can reduce during peak demand two to three times per year or is able to use its backup generators during demand response events.

Biomass Based Jet Fuel. The potential use of jet fuel manufactured from biomass sources presents a large opportunity for Miramar. There are currently several military and commercial demonstration projects of biologically based aviation fuels. However, there is currently no commercially available and affordable option to replace tactical JP-5 derived from petroleum with a fuel derived from biomass products. Miramar should monitor the technical development of the demonstration projects and look for opportunities to reduce its energy footprint with a biomass based jet fuel as soon as possible.

Fuel Delivery Systems Efficiency. Miramar should examine the efficiency of its jet fuel distribution system. Since the base consumes about 28 million gallons of jet fuel annually, the fuel distribution system should be analyzed to ensure that tanks and pipelines are performing optimally.

Commuter Fuel Use Reduction. Miramar commuters were estimated to use 2.5 million gallons of gas annually, based on assumptions provided by Miramar staff that approximately 12,500 people commuted an average of 10 miles one way each day. Changing commuter behavior is a difficult challenge, since often there is little flexibility in the number of trips required to and from work, and the number of miles required to drive to reach work. Even so, Miramar may consider the following recommendations to reduce commuter fuel consumption:

Miramar employees may be able to engage in alternative work schedules. For example, it is not uncommon for some employees to take every other Friday off, or to work from home occasionally. These types of policies have the potential to greatly reduce commuter fuel use.

Some installations have had success in ride sharing. One approach is to e-mail all employees asking for volunteers of who might be interested in sharing rides to and from work. Interested parties would provide their address information, and would be matched with other individuals living nearby.

6 Electrical Systems Assessment and Recommendations

6.1 Overview

Before installing renewable energy systems, it is important to analyze their impacts on the local distribution network. This analysis will determine whether the network can accommodate these systems and determine what major system upgrades are required.

Energy security is a primary driver for the military to incorporate renewable energy into its installations. Renewable energy systems can enhance the ability of an installation to operate in a stand-alone or microgrid scenario should the need arise.

This section presents an overview of the impact of distributed generation (DG) to the electrical infrastructure in a grid connected scenario as well as in an islanded scenario.

6.2 Impact Analysis of Distributed Generation

Resource placement and electrical interconnection. Miramar has a very robust primary electrical distribution system. The distribution system uses four sets of matched radial 12 kV feeders. These matched sets form loops that allow the base to reconfigure the distribution system for maintenance, when faults occur in the distribution system, or in the event of device failures. From an electrical standpoint, the large conductor size and relatively short feeder length used on the majority of the primary allows the proposed projects to be tied into the distribution system anywhere on the primary feeders.

When considering interconnection locations, changes to the secondary system (such as new distribution transformers, distribution transformer upgrades, and changes to the local protection system are assumed to be reasonable and should be evaluated on a project-by-project basis. Changes to the secondary distribution system that are necessary to safely implement the project should be included in the scope of individual project proposals.

The interconnection points of the proposed projects are largely based on proximity to a structure already connected to the Miramar distribution system. Table 28 shows suggested interconnection points for the proposed projects. It does not include potential landfill PV installations, but includes electrical generation of 3 MW from methane produced by the landfill as well as co-generation. Exact interconnection location may change. The table shows the distribution system loop, electrical switch, and size of each proposed interconnection. The first 33 locations represent possible PV interconnection points and the last three show the landfill electrical energy plus co-gen interconnection points. The figure showing these points on the base single line diagram is removed for publication.

Table 28. Proposed Interconnection Points

Location (Building)	Loop	Switch	Size (kVA)
AD (7209)	5/6	6-6	1,264
AE (6311)	5/6	5-2	155
AF (6001)	5/6	5-17	1,637
AG (2660 & 2661)	5/6	5-6	1,611
A (9570 & 9670)	9/10	10-7	1,505
AA (RV Storage)	3/4	3-12	1,551
AB (19315)	N/A	N/A	599
AH (2660 & 2661)	9/10	10-7	2,298
B (8630)	9/10	10-4	96
C (8671)	9/10	9-11	277
D (8672)	9/10	10-3	195
E (9470)	9/10	10-9	457
F (8380)	9/10	9-8	117
G (9175)	9/10	9-5	154
H (9500)	9/10	9-5	367
I (8600)	9/10	9-4	329
J (8402)	7/8	8-4	295
K (8402)	7/8	8-4	167
L (8402)	7/8	8-4	155
M (8473)	7/8	8-7	569
N (8461)	7/8	7-1	475
O (8116)	7/8	7-3	153
P (8116)	7/8	7-3	171
Q (8116)	7/8	7-3	164
R (7133)	3/4	4-3	474
S (6001, 6003, 6004)	5/6	5-15	707
T (6006, 6007, 6008)	5/6	5-19	445
U (6274, 6275)	5/6	5-9	174
V (6311)	5/6	5-2	750
W (5439, 5640)	3/4	3-7	494
X(5500)	3/4	3-8	162
Y (5509)	3/4	3-12	379
Z (Golf Club)	3/4	3-12	268
Landfill Electrical Energy	9/10	10-6	3,750
Co-gen 1	3/4	3-7	1,812
Co-gen2	7/8	8-6	1,025

Impact of proposed DG on existing base infrastructure. To maintain the integrity of the reconfigurable distribution system, each feeder must not only be able to support the DG that is proposed to be connected to that feeder, it must also be able to support the DG that could be switched onto the feeder via reconfiguration. Each of the two main ties to SDG&E are rated at 2,000 A, and each of the radial feeders are rated at 1,200 A.

Table 29 shows the current injection on each feeder and loop using the proposed interconnection locations from Table 28. The minimum load currents are from yearly load plots of the demand for each of the listed feeders. The aggregate minimum load for the loops was not given. Note the minimum load for the loops is not simply the sum of the minimum load for each feeder, as the minimum load on the individual feeders may not occur at the same time. However, the sum of the minimum load for each feeder is the lowest possible load current for the loop and will be used in the following worst-case analysis.

Table 29. Current Injection from Proposed Projects

Feeder	Maximum Amps from Generation	Minimum Load Amps	Maximum Amps (Generation – Load)
3	137	24	113
4	23	29	-6
5	374	29	345
6	61	34	27
7	46	17	29
8	106	29	77
9	60	26	34
10	289	22	267
Loops			
3/4	160	-	-
5/6	435	-	-
7/8	153	-	-
9/10	349	-	-
SDG&E Connections			
1	617	106	511
2	479	130	349

The worst-case impact on the electrical system of the DG listed in Table 29 if the maximum generation occurs when the load on the feeder is at its minimum. Even under these lightly loaded conditions, all feeders fall within the 1,200 A limit and both SDG&E connections are within the 2,000 A limit. Additionally, no loop exceeds the 1200 A limit with 100% of the generation and load from both feeders, and the 2,000 A limit is not exceeded on the remaining SDG&E tie if one tie is out of service.

This analysis indicates that at the proposed interconnection points to the distribution system at Miramar could potentially accommodate 18.6 MW of solar, 3 MW of landfill gas electrical generation, and 2.5 MW of cogeneration. The ability to install this large amount of renewable energy at Miramar indicates that the primary electrical distribution system is indeed very robust.

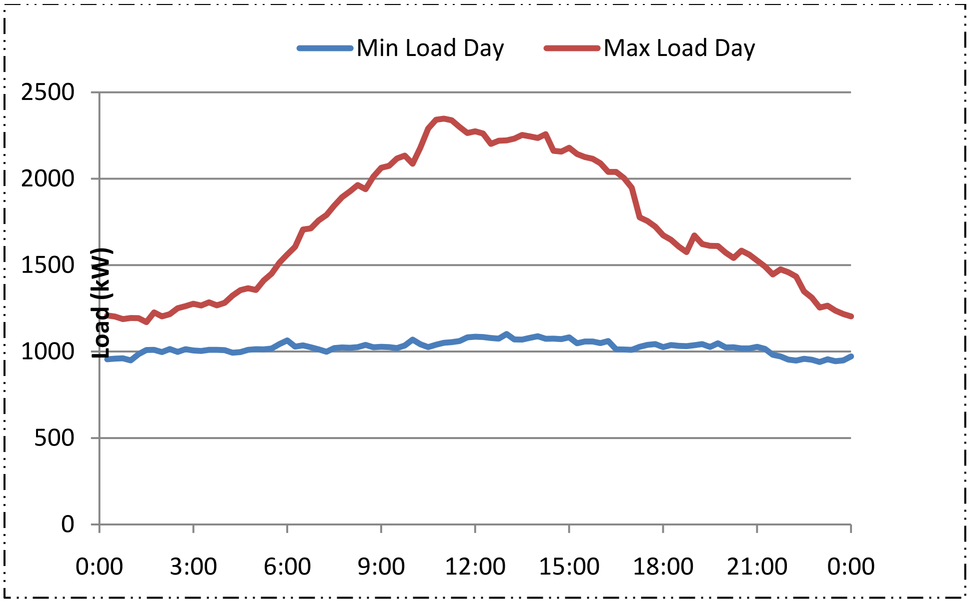

Figure 51. Aggregate critical loads for the max. and min. load days

Recommendations*:* On a microgrid, the load and generation must match exactly at all times. Generally, when sizing diesel generators for use on a microgrid, the maximum demand is the most important criteria. According to the aggregate load profiles, the maximum load for the critical load network is 2.4 MW. The critical loads on Miramar could be comfortably served with 3 MW of diesel generation.

When considering non-dispatchable generation sources such as PV, the minimum load must also be considered. The absolute minimum load for the aggregate critical loads is 940 kW. However, since PV is only available during daylight hours, only minimum values between 7:00 a.m. and 7:00 p.m. are considered. The minimum load for this time range is 1 MW; therefore, the largest amount of PV that the microgrid can support without storage or discarding energy is 1 MW. While simply discarding energy produced by PV may seem like an undesirable option, over-sizing the PV can provide added fuel saving benefit when the load is not at the minimum. The use of storage can reduce the amount of lost energy and make PV more attractive on a microgrid. These benefits are illustrated in the following section.

Ultimately, the amount of PV that a microgrid can safely accommodate is determined by the capabilities of the dispatchable generation and storage. If the controllers cannot support the inherent variability of PV generation, the amount of PV may need to be limited to maintain stability.

Microgrid Analysis (HOMER). To show the benefits of adding PV to the microgrid scenario, NREL used the HOMER modeling tool with the critical load and 3 MW diesel generators. The analysis initially looks at adding various generation levels of PV without storage to see what percent of the critical load can be met with renewable energy. The model also analyzes the benefits of adding 1.5 MW Sodium Sulfur batteries to the microgrid.

HOMER Components.

Critical Loads. The load profile used in the base case was scaled down to meet the maximum critical load determined above at 2.4 MW. The critical load maintains the same load factor of 56.3%, but scaled down to an average 31,077 kWh/day from 182,311 kWh/day. The average critical load is 1,294 kW, thus with a load factor of 56.3%, the peak critical load is 2,299 kW or 2.3 MW.

Diesel Efficiency. The actual specifications and rating for the proposed three 1 MW generators must be provided for more precise modeling. For this analysis, three diesel 1 MW 1250 kVA Caterpillar gensets are modeled to provide the backup power. The fuel consumption data from the specification were used to create the following efficiency curve in Figure 52.

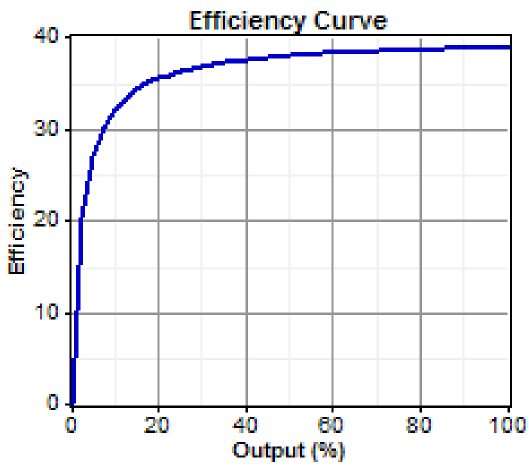

Figure 52. Genset fuel efficiency curve

The average efficiency is approximately 38%. The minimum allowable load on the generator was set to 10% of its rated capacity, as a conservative estimate. This means that if the load falls below 10% of the rated capacity, the generators will continue to run at the minimum rate. The generators will shut off if PV and/or batteries are able to meet the entire critical load.

Fuel Cost. According to the U.S. Government's Energy Information Administration[53] the average price for diesel in California is $2.85/gal ($0.75/liter).

Capital and O&M cost. The capital cost used in the model is $400.00/kW for a total capital cost of approximately $1,200,000 for the 3 MW generation. Maintenance cost is estimated to be $8.53/hour and is dependent on the hours of operation and the percent of full load that it serves.

Fuel use for Islanding Case. Operating under the condition in which the grid is down and 3 MW generators are required to supply the entire critical load would use an estimated 9,893.5 liters (2,614 gal) of diesel fuel per day. The following tables show the reduction in fuel use by adding up to 10 MW of PV to the microgrid.

[53] Energy Information Administration. Official Energy Statistics from the U.S Government Site. Weekly Retail On-Highway Diesel Prices, http://tonto.eia.doe.gov/oog/info/wohdp/diesel.asp. Accessed April 2010.

Table 30. Reduction in Diesel Fuel use with PV

PV (kW)	PV (kWh/yr)	% RE	Diesel (L) per yr	Diesel (gal) per yr	Diesel (gal) per day	Fuel Cost ($)/day
0	0	0	3,060,753.00	808,567.92	2,215.25	$6,313.48
500	778,169	7%	2,861,857.00	756,024.99	2,071.30	$5,903.21
1000	1,555,168	14%	2,663,261.00	703,561.31	1,927.57	$5,493.56
1500	2,279,373	20%	2,478,151.00	654,660.27	1,793.59	$5,111.73
2500	3,267,918	29%	2,222,905.00	587,231.20	1,608.85	$4,585.23
3000	3586408	32%	2,136,788.00	564,481.43	1,546.52	$4,407.59
3500	3875762	34%	2,055,424.00	542,987.27	1,487.64	$4,239.76
4000	4129491	36%	1,982,919.00	523,833.41	1,435.16	$4,090.21
5000	4487634	40%	1,880,921.00	496,888.31	1,361.34	$3,879.81
6000	4737677	42%	1,809,824.00	478,106.41	1,309.88	$3,733.16
7000	4,902,087	43%	1,763,629.00	465,902.94	1,276.45	$3,637.87
8000	5,033,827	44%	1,726,385.00	456,064.09	1,249.49	$3,561.05
10000	5,211,239	46%	1,676,142.00	442,791.25	1,213.13	$3,457.41

Table 31. Reduction in Diesel Fuel use with PV and 1.5 MWh Batteries

PV (kW)	PV (kWh/yr)	% RE	Diesel (L) per yr	Diesel (gal) per yr	Diesel (gal) per day	Fuel Cost ($)/day
0	0	0	3,061,583.00	808,787.18	2,215.86	$6,315.19
500	778,169	7%	2,862,664.00	756,238.18	2,071.89	$5,904.87
1000	1,556,337	14%	2,668,717.00	705,002.64	1,931.51	$5,504.82
1500	2,333,610	20%	2,476,652.00	654,264.28	1,792.50	$5,108.64
2500	3,689,289	29%	2,123,647.00	561,009.93	1,537.01	$4,380.49
3000	4150909	37%	2,003,606.00	529,298.36	1,450.13	$4,132.88
3500	4471843	39%	1,920,072.00	507,230.94	1,389.67	$3,960.57
4000	4899169	43%	1,844,015.00	487,138.74	1,334.63	$3,803.69
5000	5766012	51%	1,737,316.00	458,951.76	1,257.40	$3,583.60
6000	6162487	54%	1,657,450.00	437,853.33	1,199.60	$3,418.85
7000	6,435,103	57%	1,597,251.00	421,950.39	1,156.03	$3,294.68
8000	6,736,694	59%	1,511,036.00	399,174.72	1,093.63	$3,116.84
10000	6,965,217	61%	1,489,550.00	393,498.71	1,078.08	$3,072.52

Adding more PV without any form of storage will only generate excess power whenever PV generation exceeds the system load. This excess power is wasted, thus only around 46% of the critical load could be met with PV.

Table 31 shows how adding 1.5 MWh of battery storage can reduce the excess power wasted and increase the renewable fraction to 61%. Managing the loads and providing storage can reduce the need for diesel backup generators significantly.

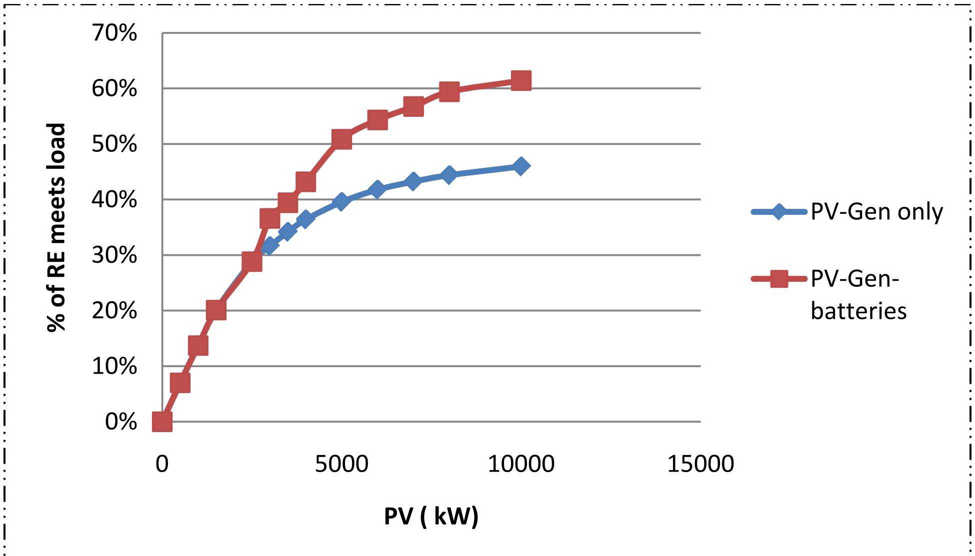

Figure 53. Percent of critical load met by renewable energy

The following graphs show how 3 MW PV with and without batteries can reduce the need for generators on January 1st, the minimum load day. Figure 54 shows how PV power can reduce the generator power required to meet the critical load. Figure 55 shows how PV power with battery storage can remove the need for diesel generator power during the maximum critical load.

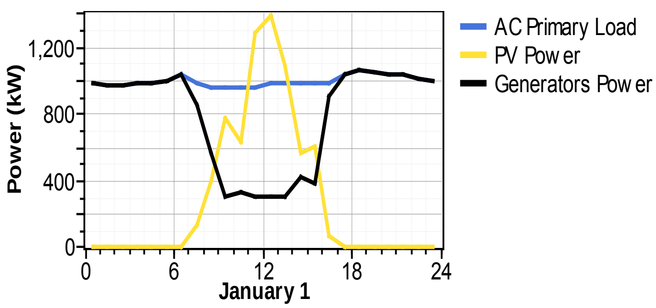

Figure 54. Microgrid without batteries

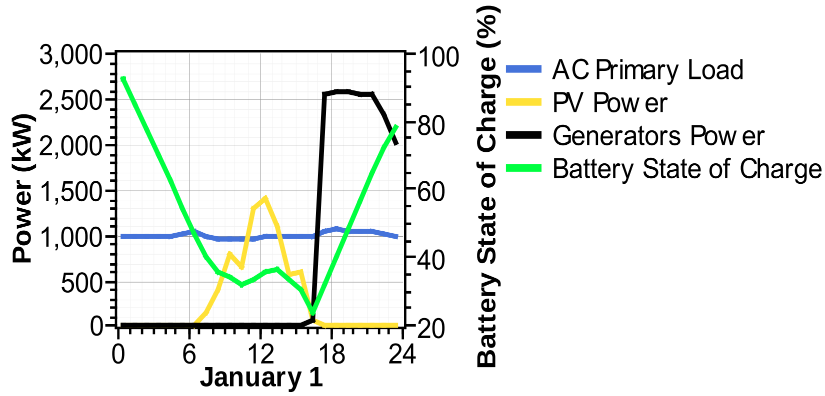

Figure 55. Microgrid With 1.5 MWh Batteries

To achieve a 100% renewable energy fraction with the 20,319 kW of PV that could potentially be installed in Miramar would require an additional 3 MWh of Sodium Sulfur (NaS) batteries.

Storage Options for a Microgrid:

Large-Scale Battery Storage.

- ***Lead-acid/NiCad Batteries***. Lead-acid batteries are the most common and are often used in conjunction with a PV system. There are two categories of Lead acid batteries: vented or valve-regulated. Vented type batteries lose gas during over-charging and require maintenance every three months to replenish their electrolyte levels with distilled water. Valve regulated lead acid cells (VRLA), often referred to as "sealed batteries," convert the gas that is created during over-charging to water on the negative electrode. The valve releases pressure that may build up.
- Another common type of rechargeable battery that is used in PV systems is nickel cadmium (NiCad). NiCad batteries are made of a solution of potassium hydroxide with plates made of nickel and cadmium submerged in the solution.
- Batteries are sized according to the amp-hour ratings or energy that they can store. Batteries last longer if they are not discharged beyond the manufacturer's recommendations. There are both shallow and deep cycle types of batteries (referring to their ability to discharge). Car batteries, which are often available in rural areas, can only be discharged to 80% to 90% state of charge. They are designed to deliver a large amount of current in a short amount of time. For remote power applications deep-cycle VRLA batteries are recommended for their low maintenance and can be discharged to 20% to 50%.
- Lead-acid battery voltage varies with the state of charge of the battery. This can fluctuate between 11.85 volts and 12.6 volts from discharged to fully charged. NiCad batteries have a constant voltage that does not change much when charging or discharging. NiCad batteries can be discharged 100% and can remain in this state for a long period of time without damage. NiCad can also operate as low as negative 30°F without losing capacity. The fact that their voltage does not fluctuate during charging and discharging, and that their capacity does not decrease at low temperatures, allows a 30% to 50% smaller battery to be used compared to lead-acid batteries.

- ***Sodium Sulfur Batteries***. Sodium sulfur (NaS) batteries are high-capacity battery systems used to support the electric grid with DG such as wind or PV. These batteries were selected for research by Massachusetts Institute of Technology in 1980 to develop a utility power storage device. The NaS battery is comprised of a liquid sulfur at the anode (positive electrode) and liquid sodium at the cathode (negative electrode). To keep the NaS in a molten state, the hermetically sealed batteries operate at 300°C. The liquid NaS is separated by alumina ceramic. These materials react rapidly with an efficiency of approximately 89%. At this time, the only company is producing NaS batteries is NGK of Japan.
- ***Lithium-ion Batteries***. Lithium-ion batteries are high-density rechargeable batteries that are becoming more popular. The advantage they have over NiCad is that they have a higher voltage (3.7 volts compared to 1.2 volts for NiCad) and hold a charge much longer on the shelf. Lithium-ion batteries will retain most of their charge after months of storage, while NiCad may lose 1% to 5% of their charge per day. Lithium-ion batteries are also lighter weight and smaller. The cost of Lithium-ion batteries is much higher than the lead-acid, making them less common and less cost effective.
- ***Zinc – Air Batteries***. Zinc-air batteries are being investigated for use in powering electric vehicles. These batteries have similar properties to fuel cells, as they are fueled by zinc and the rate of airflow can control the amount of oxygen that is used to oxidize the zinc. The batteries are powered by the oxidation of zinc with oxygen from air at a zinc electrode. The zinc-air batteries are not rechargeable, so the zinc cathodes would need to be exchanged. The used zinc cathodes can be easily recycled back to zinc. The concept is still under development and is not yet commercially available.
- ***Lithium – Air Batteries***. Unlike the Zinc-air batteries, researchers are working on developing a rechargeable lithium air battery that could increase the energy capacity 10-fold, compared to the available lithium-ion battery. The technology uses an air cathode with a lithium anode. The active cathode material is the oxygen from the air.

Diesel Uninterruptible Power Supply (UPS)

- ***Flywheel Energy Storage coupled to Diesel Generator***. A flywheel is a rotating disk that transforms electrical energy in kinetic energy and stores the rotational energy, which can later be converted back to electricity. Contained inside the housing of a flywheel is the power coupling motor generator, spinning flywheel, shaft, and advanced magnetic bearing. When the flywheel transforms the electrical energy into kinetic energy, the electrical motor accelerates a shaft until the working speed is reached. At the working speed, the electrical motor can be disconnected and the shaft will continue to spin storing the rotational energy. To reduce any friction on the flywheel, it is often placed in a vacuum. To capture the stored kinetic energy, the shaft moves like a conductor in the advanced magnet. Electronic controls are used to extract the power at the right frequency.
- To create a UPS generator /flywheel system, the flywheel is installed in parallel with the diesel generator. The flywheel reduces the start/stop events of the diesel engine, prolonging the generator life. The flywheel can also offer a fast response to eliminate

interruptions in the power. The life expected from the fly wheel is around 15 to 20 years, which is much longer than the five to six years for most batteries.

- ***Compressed Air Energy Storage (CAES)***. CAES has been around for almost 30 years and has proven to be an option for large utility-scale storage. CAES uses electricity during the off-peak to run a motor that drives a compressor and compresses air into an underground reservoir. When the energy is needed, a high pressure air turbine is used to expand the underground air. Natural gas is mixed with the exhaust from the high pressure turbine to run a low pressure turbine. This type of energy storage is usually considered a hybrid system since natural gas is required to operate. The energy used to produce one kWh of dispatchable electricity is about one third of the energy needed to run a conventional natural gas turbine.[54]

Recommendations: If a microgrid at Miramar is desired, a detailed study is recommended to determine the feasibility and equipment requirements. The above analysis is intended to illustrate the potential benefits of incorporating renewable energy sources into a microgrid at Miramar and should not be considered sufficient for microgrid planning and operation.

In addition to the recommended electrical system studies, implementing a microgrid with renewable energy, storage, and generators at Miramar will require the addition of “smart” controls. These controls would allow MCAS Miramar to manage its distributed resources and intentionally island itself from SDG&E, ensuring the ability to continue critical operations during an extended emergency. The sophisticated control system would coordinate the electrical generation systems (PV, storage, and generators) and Miramar’s critical loads to maintain grid stability. Additionally, the control system will allow safe reconnection with the SDG&E once the emergency condition has passed.

In addition to enabling operation as a stand-alone island, the control system would potentially allow Miramar to participate in local grid support activities like customer demand response. Adjustable loads, such as fleet electric vehicle charging may be coordinated with SDG&E to ensure the local grid is not taxed beyond its capabilities as the nature of distribution systems and their uses evolve in the future. A controller may also interface with building energy management systems to increase the efficiency of the distribution system by improving renewable generation and load coincidence.

The microgrid control system would consist of a central computer system that would receive data from a network of sensors strategically placed on critical base infrastructure. The system would need high-resolution load monitoring capability and the ability to follow load by dispatching generation or rapidly turning on and off generation systems. Additionally, real-time voltage, current, and frequency measurements are necessary to ensure the microgrid operates within criteria.

Recommended studies for microgrid planning and operation include:

- Voltage regulation
- Protection and coordination

[54] Moutoux, R.; Barnes, F. *Wind Integrated Compressed Air Energy Storage in Colorado*. Boulder, CO: University of Colorado at Boulder, 2007.

- Voltage stability
- Rotor-angle stability
- Frequency regulation.

When interconnecting DG, frequency and rotor angle stability should also be considered, as the utility grid is not present. Actual machine and system parameters and settings should be used for all studies. Installing a microgrid could change electrical systems operations and maintenance (O&M) requirements at Miramar. The impact on the system O&M should be considered and accounted for when designing and implementing a microgrid.

7 Miramar's Net Zero Energy Potential

7.1 Overview

This section evaluates the potential progress that Miramar is making and could make in the future towards achieving NZEI status and reducing greenhouse gas emissions.

7.2 Miramar Projects

As mentioned previously, Miramar has planned several projects to increase the efficiency of its building portfolio and expand renewable energy generation. These projects will continue to position Miramar as an energy leader and help the base meet its Federal Government and DoD energy mandates. An overview of these mandates can be seen in Appendix F. The proposed projects are shown in Table 32.

Table 32. Renewable Energy Generation Projects

Project Name	Project Size (kW)	Project Cost ($)	Yr	Project Status	Financing	Est. Production (MWh)
Landfill Gas	3,000	$0.09 - $0.13 per kWh	2012	Under consideration	PPA	25,000
PV on Carports 6311	200	$2,000,000	2010	Under contract	ARRA	298
PV on Carports 6311	300	$2,800,000	2010	Expected contract 11/09	ECIP	447
PV on Rooftop 6311	30	$240,000	2009	Under contract	ECIP	45
PV on Commissary Carports	1,000	$11,000,000	2011		ECIP	1,489
PV Rooftop 7209	500	$5,000,000	2011		ECIP	745
PV on Carports 9670	200	$2,000,000	2011		ECIP	298
600 PV Street Lights (220 watts each)	132	$4,900,000	2009 - 2011	2 of 7 Under contract	ECIP	198
CSP	100	$1,500,000	2011		ECIP	394

Table 33. Energy Reduction Project

Project Name	Project Size	Project Cost ($)	Year	Project Status	Financing	Reduction Amount
Boiler Replacement and Solar Hot Water	~30 buildings and 70 boilers	$6,000,000	2010	Just Awarded	ARRA	2,950 (MBtu) and 520 (MWh)

Miramar has begun implementing these projects. The PV system for building 6311 has already been installed and is shown in Figure 56.

Figure 56. 30 kW PV System installed on building 6311 (Credit: Samuel Booth, NREL)

The Miramar projects present the possibility for significant reduction in electrical and natural gas energy usage relative to the current baseline. A comparison of the current baseline and the Miramar-proposed projects is provided in Figure 57. The figure shows that the planned projects will reduce the total annual base source Btu by 36%. This reduction is comprised of a 43% electrical source Btu reduction, a 2% natural gas source Btu reduction, and zero fleet source Btu use reduction.

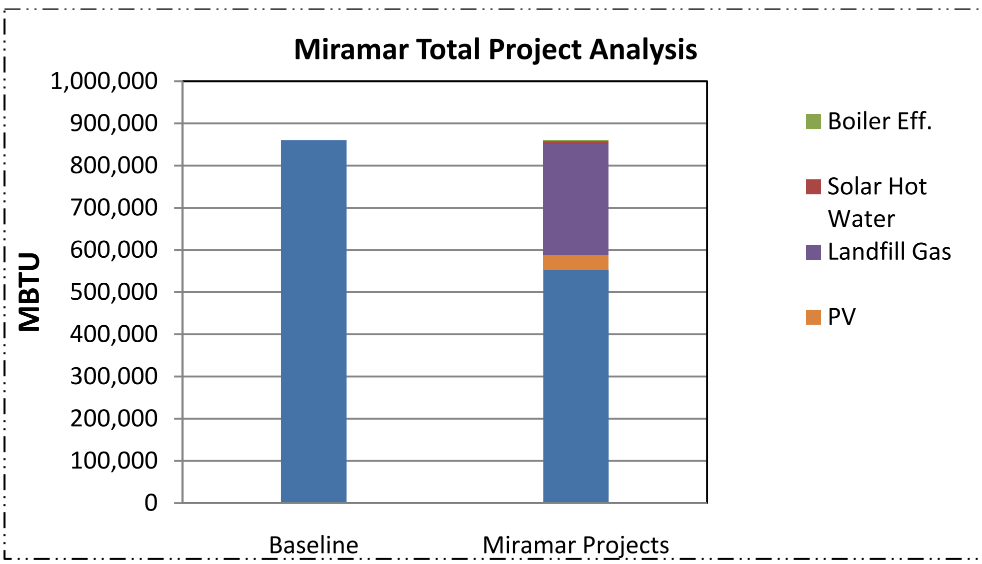

Figure 57. Miramar total energy project comparison

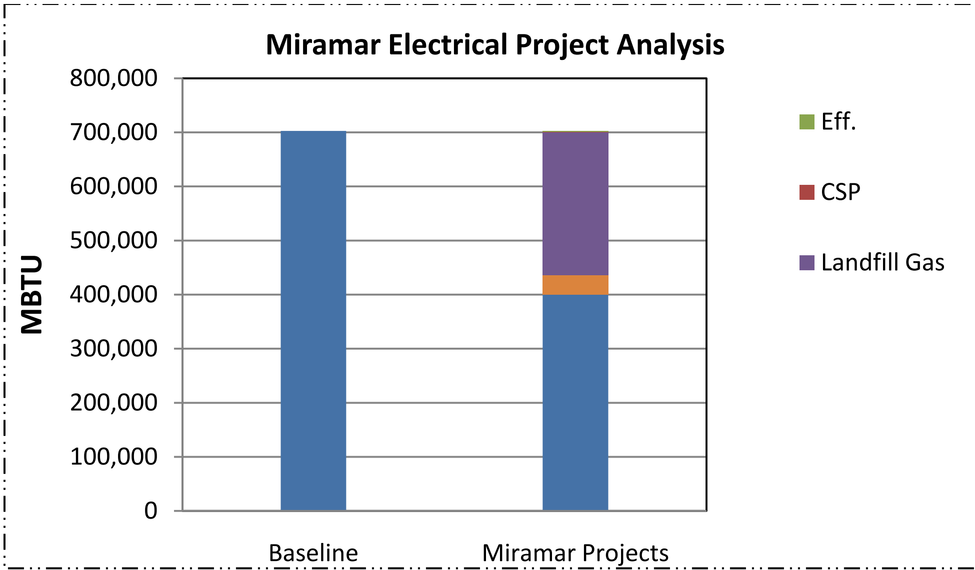

Figure 58. Miramar electrical energy project comparison

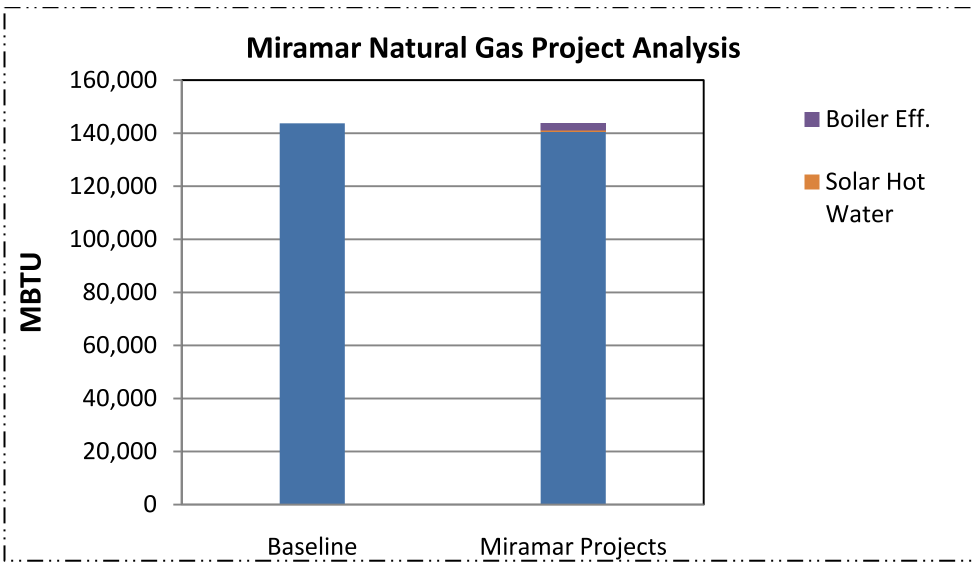

Figure 59. Miramar natural gas project comparison

7.3 Recommended Additional Energy Projects

To achieve net zero energy status, Miramar will need to implement several additional energy projects from the options analyzed in Section 5. When choosing projects, careful consideration must be given to the base's energy goals, environmental concerns, energy security, and economics as well as technical feasibility. NREL assumed that an ESPC or UESC contract would be undertaken to implement energy load reduction measures such as daylighting, solar hot water, and various energy efficiency measures. NREL also recommends the installation of additional PV and CHP powered by renewable energy. When deciding between PV and CHP, cost is an important consideration.

The recommended energy project options for Miramar are presented in Table 34. These projects will not make Miramar a NZEI, but they will help the base make significant progress and meet its energy-related objectives and goals.

Table 34. Additional Energy Project Overview

Additional Energy Generation Projects					
Project Name	**Project Size (kW)**	**Project Cost ($)**	**Year**	**Implementation**	**Production (MWh)**
Fuel Cell	2800	Estimated at $0.13 per kWh	2011 and 2012	PPA	23,000
PV	2,216	$14,979,855	2012	ESPC, UESC, or PPA	3,300
Microturbines	180	$391,500	2011 and 2012	ESPC	1,005
Electrical Load Reduction					
		Project Cost ($)	**Year**	**Implementation**	**Reduction Amount (MWh)**
Electrical Energy Efficiency		$4,286,461	2011 and 2012	ESPC	9,590
Daylighting		$630,000	2011 and 2012	ESPC	1,099
Natural Gas Load Reduction					
		Project Cost ($)	**Year**	**Implementation**	**Reduction Amount (MBtu)**
Fuel Cell		No Cost	2011 and 2012	PPA	53,814
Natural Gas Energy Efficiency		$1,461,174	2011 and 2012	ESPC	11,154
Solar Hot Water		$1,356,500	2011 and 2012	ESPC	4,570
Solar Pool		$300,000	2012	Appropriations and ESPC	6,700
Microturbines		$391,500	2011 and 2012	ESPC	(13,713)

7.4 Net Zero Energy Potential

The recommended energy project scenario presents the opportunity for Miramar to implement energy projects that will move the base towards NZEI status. If the base implements these projects, it will reduce its non-renewable total source Btu by 90%. In this scenario, the base does not quite reach NZEI status because it is still purchasing 8% of its Btu as natural gas from the grid and 2% of its Btu as non-renewable transportation fuel. If the base took measures to use renewable natural gas and renewable transportation fuel, then it could become a net zero energy installation.

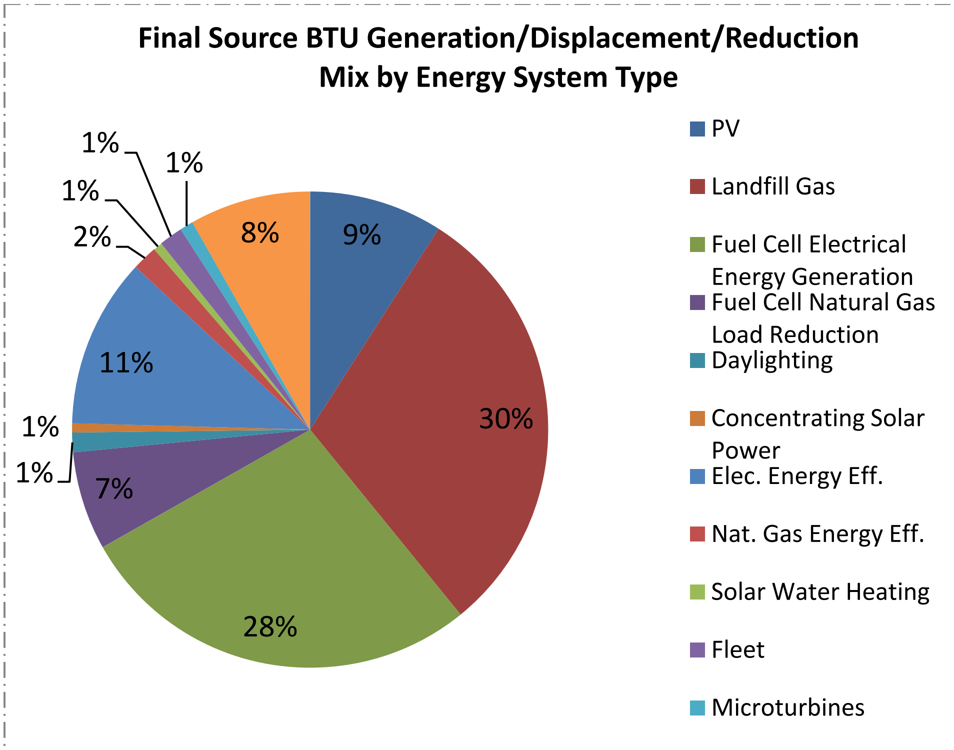

Figure 60. Final Source Btu generation/reduction mix by energy system type

Electrical Energy. Energy efficiency and on-site generation would replace approximately 700 billion source Btu of purchased electrical energy. Figure 61 shows the breakdown of the electrical load after these measures are complete.

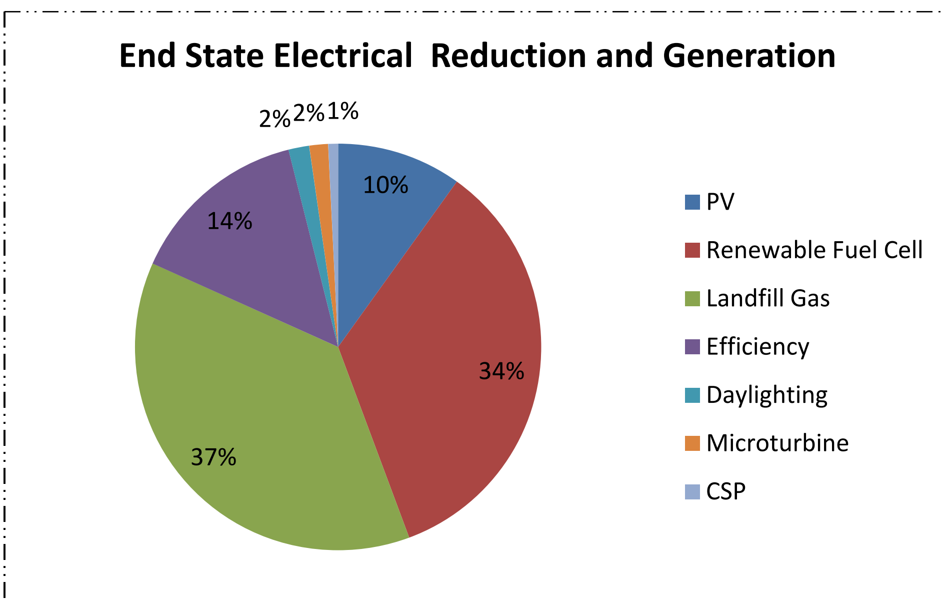

Figure 61. End state electrical reduction and generation

For the base to be classified as a NZEI, all electrical energy must be generated on-site from renewable sources. For this scenario, 16% of the load is met by various energy efficiency measures; 48% of the electrical load is met by direct on-site generation from PV, landfill gas, and CSP; 34% is met by on-site generation with the fuel cell with renewable fuel coming from off-site; and 2% is met by on-site generation from the natural gas-powered microturbine.

Natural Gas. By undertaking the recommended natural gas reduction projects, the base would reduce its natural gas consumption by 50%. The natural gas pipeline load is reduced from 131,000 MBtu to 66,000 MBtu. Energy efficiency, energy supplied by the solar water heating systems, and fuel cells powered by renewable energy, replace purchased natural gas. The total amount of thermal Btu usage increases to 140,000, to account for the additional natural gas used by the CHP microturbines. Figure 62 shows the breakdown of the natural gas load after these measures are complete.

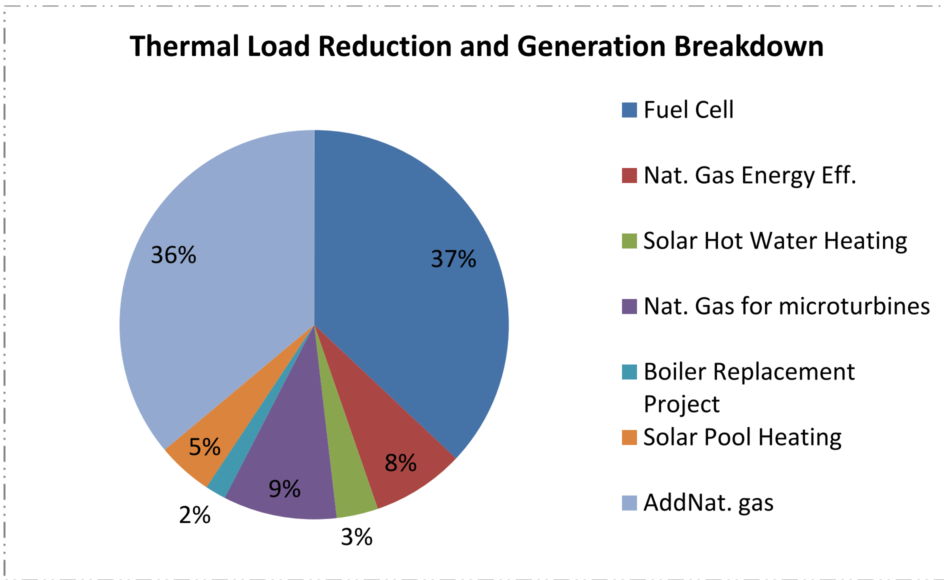

Figure 62. Thermal load reduction and generation breakdown

By reducing these loads and installing on-site systems to displace natural gas such as solar hot water and solar pool heating systems, the base becomes closer to a net zero installation. However, because only about 50% of the natural gas load was displaced, net zero status is not achieved. If the base wanted to become a NZEI, it could purchase renewable natural gas from the same company offering the fuel cell PPA project for approximately $14 per MBtu. An additional way for the base to become a net zero installation would involve installing large amounts of renewable electric power generation, such as PV, then switching to entirely electrical space- and water-heating systems.

Transportation. If the recommended improvements to the vehicle fleet were implemented to use E85 and expand biodiesel use, we would see a reduction of 67,000 gallons of gasoline and 2,000 gallons of diesel. The new fuel use breakdown (in gallons) for transportation is shown below.

Table 35. Estimated Revised Transportation Fuel Use

Diesel	8,000
Biodiesel	33,000
Compressed Natural Gas	45,000
E85	67,000
Gasoline	22,500

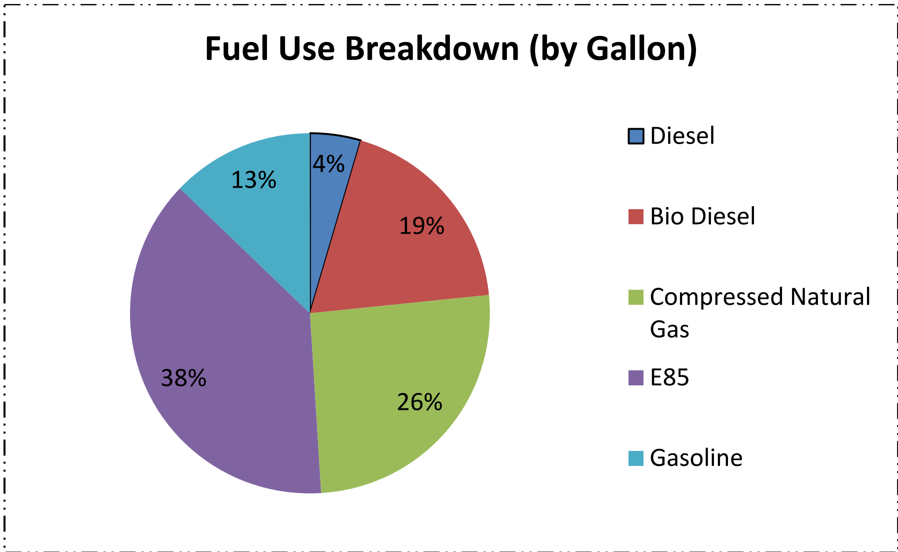

Figure 63. Miramar recommended scenario fuel use breakdown

For renewable fuel accounting purposes, E85 is considered by the government as a 100% renewable fuel and B20 biodiesel is considered as a 20% renewable fuel. In this scenario, non-renewable fleet fuel use is reduced by 9,400 MBtu. This represents a 40% reduction in fleet source MBtu.

7.5 Greenhouse Gas Reduction

GHG emissions were calculated over the next five years by considering the planned implementation projects for reducing Miramar's energy use to net zero. The GHG emissions for 2012 are 4497 tons and represent a GHG emissions reduction of by 85% from the baseline emissions of 30,183 tons in 2008. The time phased GHG reduction is shown in Figure 64.

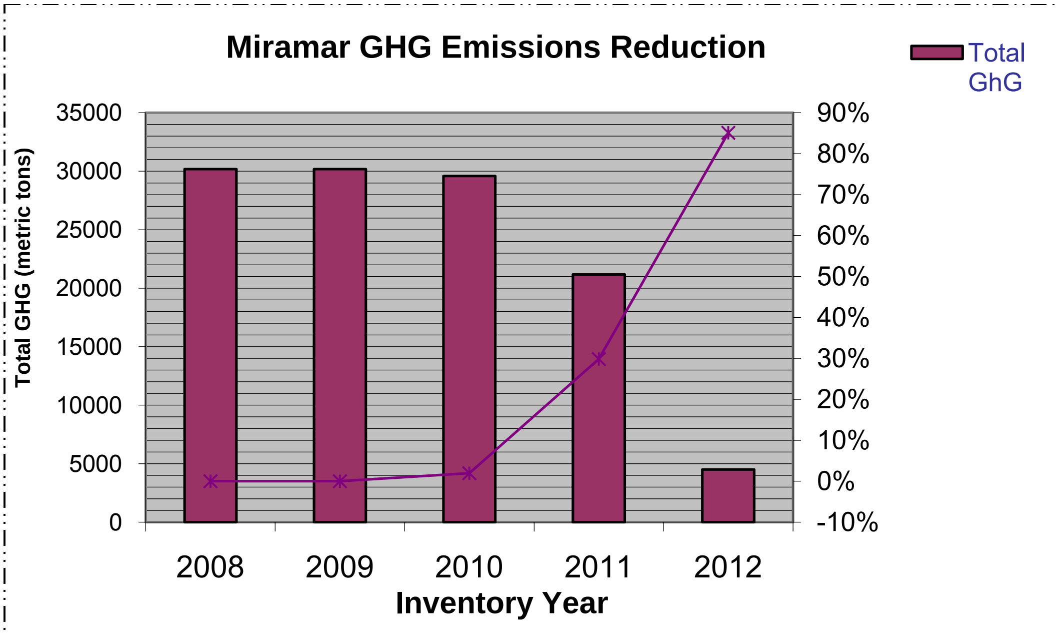

Figure 64. Miramar GHG emissions reductions

8 Implementation: Project Planning and Financial Assessment

8.1 Overview

This section provides an overview of the implementation options available to Miramar, a time-phased implementation analysis, and a basic financial assessment.

8.2 Implementation Options

Miramar has a variety of available options for implementation of the additional recommended energy projects. A description of these options is presented below.

Information on financing mechanisms adapted directly from the FEMP Financing Mechanisms Web site at www.femp.energy.gov/financing/mechanisms.html.

Energy Savings Performance Contracts. ESPCs allow Federal agencies to accomplish energy-savings projects without up-front capital costs and without special Congressional appropriations.

An ESPC is a partnership between a Federal agency and an energy service company (ESCO). The ESCO conducts a comprehensive energy audit for the Federal facility and identifies improvements to save energy. In consultation with the Federal agency, the ESCO designs and constructs a project that meets the agency's needs and arranges the necessary financing. The ESCO guarantees that the improvements will generate energy cost savings sufficient to pay for the project over the term of the contract. After the contract ends, all additional cost savings accrue to the agency. Contract terms up to 25 years are allowed.

The average contract price for a Super ESPC contract undertaken by a Federal agency between 1998 and 2008 was $15.3 million.[55] Typically ESPC contracts need to be at least $1 million to $2 million in size to generate interest from the private sector.

Utility Energy Services Contract. Another way for Federal agencies to implement efficiency and renewable energy projects is through utilities. Federal agencies often enter into UESCs to implement energy improvements at their facilities. With a UESC, the utility typically arranges financing to cover the capital costs of the project. Then the utility is repaid over the contract term from the cost savings generated by the energy efficiency measures. With this arrangement, agencies can implement energy improvements with no initial capital investment; the net cost to the Federal agency is minimal, and the agency saves time and resources by using the one-stop shopping provided by the utility.

Power Purchase Agreements (PPA). PPAs allow Federal agencies to finance on-site renewable energy projects with no up-front capital costs incurred. With a PPA, a developer installs a renewable energy system on agency property under an agreement that the agency will purchase the power generated by the system. The agency pays for the system through these power payments over the life of the contract. After installation, the developer owns, operates, and maintains the system for the life of the contract.

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[55] Federal Energy Management Program. Super ESPC Awarded Delivery Orders Summary. DOE Awarded Task Order Report. Awarded Energy Service Performance Contacts, www.eere.energy.gov/femp/pdfs/do_awardedcontracts.pdf. Accessed 8-24-09.

Appropriations ECIP, ARRA, etc. Energy projects can also be founded directly through agency or government budget mechanisms. For example, the projects currently being undertaken at Miramar will be funded by either the ECIP through the military or the ARRA through the Federal Government. Funding through these mechanisms has the advantage of reduced project financing costs. However, government funded projects are not eligible for the benefits of renewable energy generation tax credits.

8.3 Other Implementation Considerations

Net Metering. The ideal method for Miramar to connect its distributed energy generation systems to the electric grid is through net metering. Net metering reduces Miramar's electric bill by subtracting the renewable energy generated from the utility bill. If a renewable energy system generated more electricity than the current load, the additional energy can be "stored" on the electric grid to offset consumption later. A customer is allowed to net meter up to 100% of their total consumption. However, California's net metering system size limitation is 1 MW per customer premise. The size limitation is based on section 2827 of the Public Utility Code. NREL discussed the number of potential customer premises with SDG&E and the Miramar Base Energy Manager. Miramar is believed to have at least three eligible customer premises: the Main Base, the Commissary, and the Exchange. Additionally the clinic, the Brig, and the privatized housing may also count as eligible customer premises. Renewable energy generation projects could be located on site behind their respective electrical meters.

Interconnection Requirements. NREL recommends that Miramar install renewable energy generation systems with a capacity well beyond 1 MW. The next steps required for interconnection of projects beyond 1 MW but less than 10 MW come from California Rule 21. This rule specifies standard interconnection, operating, and metering requirements for DG systems. The goal of Rule 21 is to setup a screening process to qualify systems for simplified interconnection. The first step in the Rule 21 application process is for the utility to perform an Initial Internal Review. The utility follows a checklist to determine whether a project qualifies for simplified interconnection. If it does not qualify, the project must undergo a Supplemental Review Process. This process determines whether a project can qualify for a simplified interconnection with a few additional requirements. If it cannot, the system must undergo an interconnection study. The costs of this study are determined by the utility, but paid by the system owner. The customer is subject to standby and departing load charges. Additionally, each system greater than 1 MW must be equipped with a generation output meter. A common "rule of thumb" is that if an intermittent generation source such as PV is used and provides more than 15% of the load on a particular utility circuit, it will likely not qualify for simplified interconnection.

Systems larger than 10 MW but less than 20 MW will be subject to small generation interconnection procedures. These typically involve a systems impact study, a feasibility study, and a facility study. Details of the small generation interconnection process are provided in Appendix K.

Power Prices. The price that Miramar's electric utility will likely pay to purchase power that does not qualify for net metering or other incentive programs depends on the specific deal reached. There are three likely scenarios under which power could be sold back to the utility:

1. Pursue a transaction under the utilities-avoided cost, pursuant to the state's implementation of the Public Utilities Regulatory Policy Act (PURPA).

2. Bid into the utility's annual renewable energy portfolio solicitation.
3. Negotiate a bilateral contract.

The minimum price that would likely be paid to Miramar for renewable power is the utility's market price referent (MPR). The MPR is based on the anticipated cost of producing energy from a combined-cycle natural gas plant. The MPR for a 20-year contract in 2009 in California was $0.113 per kWh for base-load power.[56] Utilities will likely pay a price premium for power generated during peak demand periods. The generation profile of solar panels is such that they are often generating during peak power demand. The most likely option would be a negotiated price somewhat higher than the MPR for solar projects installed at Miramar to account for the additional cost and additional benefits of renewable energy generation. The actual price paid for contracts by utilities is kept confidential. However, an experienced consultant can provide insight into recent contracts and assist with negotiations.

Incentives. Renewable energy projects at Miramar would likely be eligible for a variety of state and Federal incentives. Energy projects at Miramar could also be eligible for tax credits if they were owned by a third party with tax liability. An overview of the incentives is presented below.

- Federal Investment tax credit or rebate for PV, CSP, and solar hot water systems – 30% credit of the capital cost.
- California Solar Initiative production incentive for PV and CSP systems above 50 kW – payment per kWh produced from systems, $0.22 per kWh for systems owned by private sector, and $0.32 for systems owned by government.[57] Up to 1 MW of capacity per customer premises is eligible for the incentive for five years.
- California Solar Initiative solar hot water heating SDG&E pilot program is $15 per ft^2, up to $75,000 total.[58]
- The California SGIP provides incentives for fuel cells powered by renewable energy as discussed in the fuel cell CHP section. Additionally, this program provides incentives for advanced energy storage. Miramar would be eligible for a $2.00 per watt incentive for a battery energy storage system.
- Modified Accelerated Depreciation Schedule – A program to reduce tax liability through faster-than-normal depreciation. Approximate schedule is shown in Table 36.

Table 36: Depreciation Schedule

Year	1	2	3	4	5	6
Fraction	0.200	0.320	0.192	0.115	0.115	0.058

[56] 2008 Market Price Referent Model. California Public Utilities Commission, www.cpuc.ca.gov/PUC/energy/Renewables/mpr. Accessed April 2010.
[57] California Solar Initiative, Statewide Trigger Point Tracker, CCSE Step 5 rates. www.csi-trigger.com/. Accessed April 2010.
[58] Solar Water Heating Program, Center for Sustainable Energy, http://energycenter.org/index.php/incentive-programs/solar-water-heating-pilot-program. Accessed April 2010.

NEPA. When planning for and installing the energy projects, Miramar must be aware of NEPA considerations. NEPA requires Federal agencies to consider the environmental impacts of projects. The requirements for NEPA vary, based on the specific project undertaken. There are three possible levels of required analysis: categorical exclusion, environmental assessment, and an environmental impact statement.[59] Building energy efficiency upgrades, rooftop energy systems such as PV, daylighting, and solar hot water could qualify for categorical exclusion because they are modifications to existing facilities. However, projects such as ground-mount PV or CSP could require more detailed NEPA assessments because they are disturbing land. The environmental assessment would be required to determine if these projects would have a significant environmental impact. If it was determined that the projects would have a significant environmental impact, a more detailed environmental impact study would be required.

8.4 Implementation Plan

The expected implementation year for the energy projects already planned by the base are shown in Table 37. These projects are all funded through government financing mechanisms or PPAs and do not require additional third party funding.

Table 37. Implementation Year for Miramar Projects

Project Name	Project Size (kW)	Year
Landfill Gas	3,000	2012
PV on Carports 6311	200	2010
PV on Carports 6311	300	2010
PV on Rooftop 6311	30	2009
PV on Commissary car ports	1,000	Estimated in 2011
PV Rooftop 7209	500	Estimated in 2011
PV on Carports 9670	200	2011
600 PV Street Lights (200 watts each)	132	2009-2011
CSP	100	2011
Boiler Replacement and Solar Hot Water	~30 buildings and 70 boilers	2010

An implementation plan was developed for the additional energy projects recommended by NREL after examining the implementation options available to Miramar and evaluating other pertinent factors such as incentives. NREL believes that a PPA deal is a good option for the renewable fuel cell CHP project. The implementation plan was developed based on one fuel cell being installed in area 5 in 2011 and one fuel cell being installed in area 8 in 2012.

ESPC contract and UESC contract options were evaluated for implementation of energy efficiency measures and an additional PV system at the base. SDG&E would be able to enter a UESC contract with the base. The UESC contract could allow for a utility PPA for the solar project, sole sourcing of the contract directly with the utility, and simpler interconnection. However, an ESPC contract is a more familiar contracting mechanism for the base, as it has executed them in the past. Using either

[59] National Environmental Policy Act. U.S. EPA, www.epa.gov/Compliance/basics/nepa.html. Accessed April 2010.

performance contracting mechanism would potentially allow the base to include all of the recommended energy efficiency measures, as well as solar water heating, daylighting, and microturbines, into one contract. Having one contract will reduce the transaction cost for the base. NREL recommends that the base also consider including the additional recommended 2.2 MW of PV into this contract. In an ESPC, PV could be installed under an energy services agreement, which would function much like a PPA transaction. However, the base should compare the cost of adding PV to the ESPC with bids from third-party solar PPA providers, and choose the best value option.

In order to determine an implementation plan, an ESPC contract and PPA deals were assumed. It was estimated that the ESPC contract would go out for bid and be awarded in 2010. It was assumed that construction would last for two years, 2011 and 2012. For simplification, the savings are assumed to occur at the beginning of the year of construction. It was assumed that the recommended switch to E85 and increased biodiesel usage occurs in 2011. The source Btu reduction resulting from an ESPC contract with PV, fleet fuel reduction, and the renewable fuel cells are shown in Figure 65.

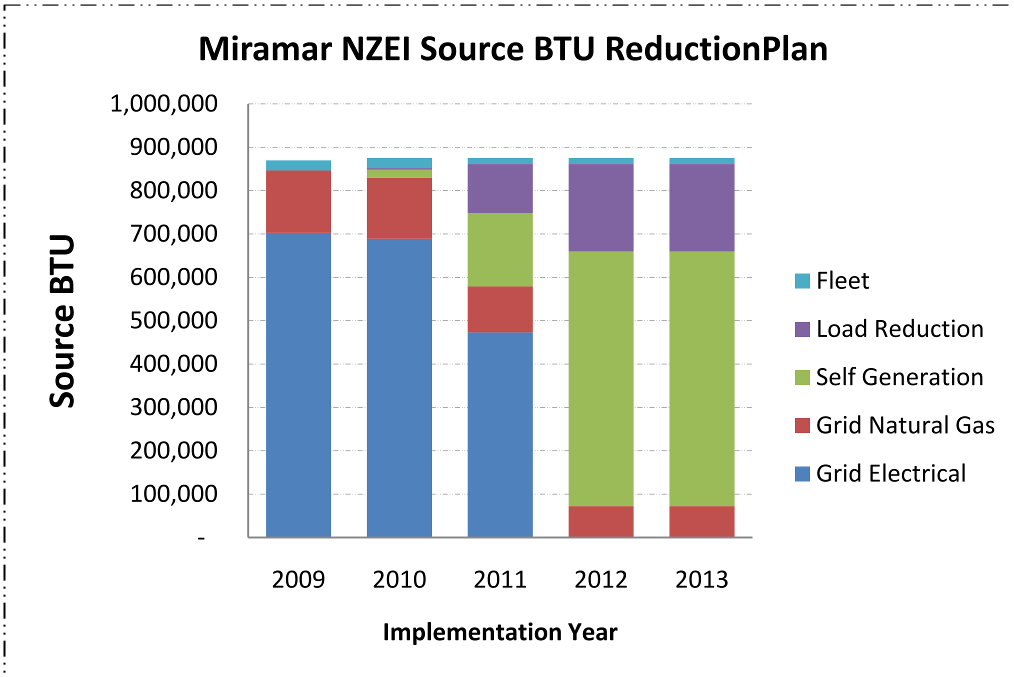

Figure 65. Miramar NZEI source Btu reduction plan

8.5 Financials

Base Energy Projects. The base has numerous energy projects underway already. The following costs are estimated for these projects:

- 2.3 MW of PV systems = $23 million
- 600 PV street lights =$ 4.9 million
- 100 kW CSP system = $1.5 million
- Boiler replacement and solar hot water systems = $6 million
- **TOTAL = $35.4 million**

Energy Efficiency Financials. The cost for the recommended energy conservation measures was estimated using the Super ESPC Awarded Delivery Order Summary[60] (This summary is provided in Appendix L). This summary details the cost-per-site MBtu of savings for Federal ESPC contracts. The data used was the average project investment per annual MBtu savings from the years 2005 to 2009. This value was $131.34 per MBtu. This does not reflect the actual contract price, which includes the cost of financing. The average contract price over the last five years was $337.28. The actual investment to energy savings ratio for an ECM will vary substantially, due to the heterogeneous nature of energy efficiency investments. Costs, risk, and return vary greatly depending on building type, building location, current level of efficiency, energy prices, available incentives, and the specific package of energy conservation measure chosen.

The average cost per MBtu of energy at Miramar is $33.38 ($46.89 per MBtu of electrical energy and $10.35 per MBtu of natural gas). Using the project investment price of $131.34 per MBtu of savings, this indicates a four-year simple payback for energy efficiency investments at Miramar. An analysis of the $1.2 B in Federal ESPC contracts concluded that the average median payback period for an investment was six and half years.[61] Miramar's payback is faster due to its higher than average cost of energy. Some of the energy conservation measures with paybacks often less than five years include: retro-commissioning, peak load reduction, advanced metering, electrical distribution systems upgrades, and cogeneration. The payback period for Miramar's energy efficiency investments will depend heavily on the energy conservation measures chosen.

With such a large difference between the project investment price and the contract price, it is worth comparing the implementation option of an ESPC contract with an appropriations-funded energy efficiency investment. The life-cycle costs of appropriations-funded projects versus ESPC contracts have been shown to be approximately the same when all costs and the longer time cycle of appropriations funding are included.[62] Figure 66 shows the cost elements of appropriations-funded projects versus ESPC implementation cost elements. The cost elements are virtually identical, but they vary by execution and funding.

Graphs of the implementation cost difference between ESPC and appropriations-funded projects are provided in Appendix L. These graphs illustrate that the total cost for an energy conservation measure when compared to the amount of savings delivered is a relatively linear function and is the same regardless of whether the project was funded by an ESPC or appropriations. Thus, there is no statistically significant difference between the total implementation price, regardless of the implementation vehicle chosen.

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[60] Federal Energy Management Program. Super ESPC Awarded Delivery Orders Summary. DOE Awarded Task Order Report. Awarded Energy Service Performance Contacts, www.eere.energy.gov/femp/pdfs/do_awardedcontracts.pdf. Accessed 8-24-09.

[61] Choate. ESPC, ECM, ft^2 What do the Numbers Tell us? FEMP Offsite Meeting. 6-30-09.

[62] Hughes, P.J.; Shonder, J.A.; Sharp, T.; Madgett, M. Evaluation of Federal Energy Savings Performance Contracting-Methodology for Comparing Processes and Costs of ESPC and Appropriations Funded Energy Projects. ORNL/TM-2002/150. Oak Ridge, Tennessee: Oak Ridge National Laboratory. 2003.

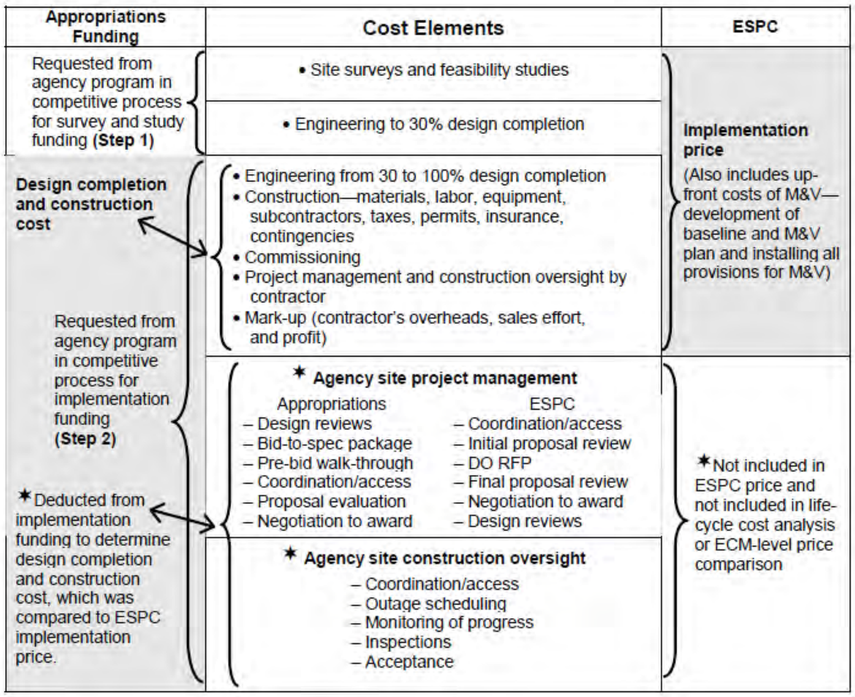


Figure 66. Cost elements ESPC versus appropriations[63]

Because the costs for an ESPC contract versus an appropriations funded project are similar, and it does not seem likely that there will be additional appropriated funds available to the base to execute all of these projects, an ESPC or other performance contract appears to be the best implementation option.

The following preliminary cost estimates were developed for the recommended energy efficiency and load reduction measures:

- Energy efficiency measures = $5,700,000
- Daylighting = $630,000
- Solar hot water = $1,350,000
- Solar pool heater = $300,0000
- Microturbines = $390,000
- PV = $15,000,000.

PPA Deals. The fuel cell powered by renewable energy and landfill gas electricity will be structured as PPA deals. The actual prices for these PPA deal are not yet determined. The fuel cell was estimated to cost $0.13 per kWh for electricity. The energy price was estimated to range between $0.9 to $.13 per kWh for the landfill gas project. For two fuel cells, the total annual spending will be $3.0 million for 23,000 MWh. For this analysis, the landfill gas project was estimated to cost $0.11 per kWh for 25,000 MWh, and the annual spending will be $2.8 million.

[63] Shonder, J.; Hughes, P.; Atkin, E. Comparing Life Cycle Cost of ESPC and Appropriations Funded Projects: An Update to the 2002 Report. ORNL/TM-2006/138. Oakridge, Tennessee: Oak Ridge National Laboratory, 2006.

Utility Costs. NAVFAC maintains and operates the base distribution network. The current electrical energy price at Miramar is approximately $0.15 per kWh. About $0.04 of this or 25% of the cost goes to pay costs at NAVFAC, while the remaining amount approximately $0.11 per kWh is the amount paid to SDG&E to purchase electricity. When the base undertakes energy projects, it is assumed that the $0.04 per kWh payment to NAVFAC will still need to be made. Thus, while the base has acquired enough electrical energy generation to meet its entire load in a net metered capacity, they will still be required to pay NAVFAC for their services. Based on the baseline consumption of 66,000 MWh per year, it is assumed that the payment to NAVFAC will be $2.64 million per year.[64] For the purpose of financial analysis, it was assumed that the price for displacement of electrical energy would be $0.144 per kWh in 2010 and $0.163 in 2011. After 2012, the price of electrical energy was projected to increase at 1% above the rate of inflation or 2.2% annually. The current natural gas price paid by the base is $11.32 per MBtu. NAVFAC does not charge a natural gas add-on fee to Miramar; that will need to be paid to NAVFAC for the displacement of natural gas loads. NAVFAC's estimated price was $11.36 for 2011. Analysis was conducted using the current natural gas price of $11.32 and the estimate of $11.36 for 2011, with an escalation rate 1% above the rate of inflation or 2.2% annually.

Cash Flow Analysis. The information above, along with a 20-year project lifetime, was used to estimate savings from the energy projects being undertaken by the base. The baseline scenario for the cash flow analysis is the current energy costs of the base. These are shown in Table 38.

Table 38. Baseline Energy Costs 2010

Base Case	
Year	2010
Grid Electricity (MWh)	66,544
Electrical Cost per kWh	$ 0.144
Total Elect Cost	$ 9,582,236
Natural Gas (MBtu)	131,615
Natural Gas Cost	$ 11.32
Total Nat Gas Cost	$ 1,489,881
Total Cost	$ 11,072,217

Over the 20 next years, it is projected that the base would spend approximately $337 million on energy. The present value of this spending on energy would be $236 million.[65] The projected costs for the next 10 years are shown in Figure 67.

[64] NREL was unable to obtain an updated estimate or confirmation of this number from NAVFAC.
[65] Rushing, A.S.; Lippiatt, B.C.
Energy Price Indices and Discount Factors for Life-Cycle Cost Analysis – 2009. NISTIR 85-3273-24. U.S. Department of Commerce, prepared for FEMP. Rev. May 2009 (NPV value is based on a discount rate of 3%. The 3% value is from NIST Energy Price Indexes and Discount Factors). www.nist.gov/customcf/get_pdf.cfm?pub_id=902817. Accessed April 2010.

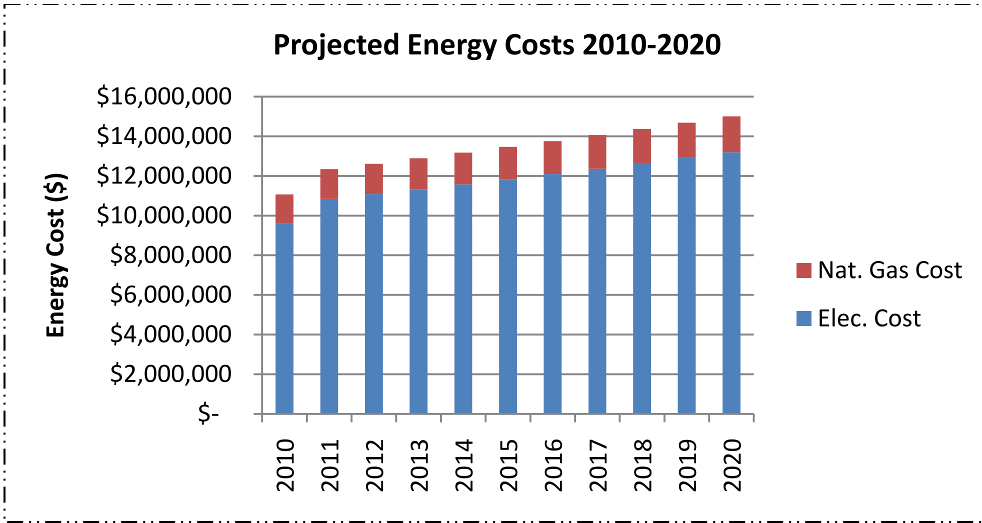


Figure 67. Projected energy costs 2010 – 2020

The assumptions for this base case analysis were:

- Electrical energy prices of $0.144 per kWh in 2010 and $0.163 per kWh in 2011. These prices are from NAVFAC estimates. For the years after the 2011, the price is adjusted by 2.2% annually. This 1% above the projected inflation rate.
- Natural gas prices of $11.32 in 2010 and $11.36 for 2011. These prices are from NAVFAC estimates. For the years after the 2011, the price is adjusted by 2.2% annually. This 1% above the projected inflation rate.

Recommended Energy Projects. A basic financial analysis of the recommended solution to approach net zero is presented in the following section. This analysis provides a sample case and does not necessarily represent the actual financial costs of these recommendations. The actual financial costs will be affected by as yet undetermined factors such as: incentive availability, installation year, energy prices at the time of installation, NAVFAC rates, and interconnection options.

The financial analysis is presented here is for discussion purposes. It was assumed that all additional energy savings projects would be implemented under and ESPC contract. NREL's Super ESPC Financial Analysis Tool was used to approximate ESPC contract prices. The results from this tool yielded a direct expense of $24.1 million and total investment cost of $32.6 million for the following ECMs:

- Natural and electrical gas energy efficiency
- Daylighting
- Solar hot water
- Solar pool heater
- Microturbines
- PV

The total investment cost includes additional items such as monitoring and verification, management and administration, and profits that are not included in the direct cost. The simple payback of the investments is 14.2 years. The calculated payoff term is16 years. The estimated cost savings are $42.6 million and the total contractor payments are $41.0 million.

After Year 16, the base will accumulate the entire savings of approximately $3.0 million.

The following assumptions were used in the ESPC tool:

- The electrical and natural gas energy efficiency costs were estimated using the historical national average for an ESPC contract.
- Electrical energy price of $0.144 per kWh
- Natural gas energy price of $11.32 per MBtu
- Utility cost escalation rate of 2.2%
- Financing rate of 5.7%
- Overall markup of 31.8%
- Financing procurement price of $1.8 million
- Pre-performance period payment of $1.1 million
- 100% of estimated savings are guaranteed by the ESCO
- 24-month construction period
- Total capital requirement of $31.9 million
- Third party ownership of the additional 2.2 MW solar PV was assumed. The power system owner was assumed to take advantage of the 30% investment tax credit and a California incentive for a five-year production tax credit at $0.22 per kWh. NREL did not attempt to estimate a PPA price. For analysis purposes, it was assumed that this solar system would displace power at the standard power rate and the capital cost for the system would be built into the ESPC contract.
    - It is recommended that the system be installed under an energy services agreement in conjunction with an ESPC. However, a standard PPA or a utility PPA would yield similar results.
    - A recent PPA deal at the Alvarado Water Treatment Plant in San Diego appears to have gotten a PPA rate of $0.12 per kWh with a 1% annual escalation rate.[66]
- O&M cost increases were estimated for the solar hot water, microturbines, and PV system. The total O&M cost increase used was $38,931 annually. No additional O&M costs or savings were estimated.
- From this tool, a payment schedule was developed for 16 years of payments to the ESCO. The payment required varies from year to year, however, the average payment

[66] Business Bank on Solar Power, Green Tech. CNET News, http://news.cnet.com/greentech/?keyword=PPA. Accessed April 2010.

over the 16-year contract lifetime was $2.6 million. This payment stream was built into a larger financial analysis that included the PPA projects and already planned installation projects.

- The financial analysis was conducted over a 20-year project lifetime using the assumptions below.
- All Miramar initiated projects were enacted at their estimated costs.
- The ARRA funded boiler replacement project reduced annual O&M costs by $300,000 annually.
- Two fuel cells projects (powered by renewable energy) were undertaken as PPAs estimated at $0.13 per kWh and the thermal energy from the fuel cells was provided at no cost.
- The landfill gas project was estimated to be a PPA undertaken at $0.11 per kWh.
- A discount factor of 3% from NIST 2009 Energy Price Indices Analysis report was used.
- A inflation rate of 1.2% annually from was NIST 2009 Energy Price Indices Analysis report was used.
- Electrical energy prices of $0.144 per kWh in 2010 and $0.163 per kWh in 2011. These prices are from NAVFAC estimates. For the years after the 2011, the price is adjusted by 2.2% annually. This 1% above the project inflation rate.
- Natural gas prices of $11.32 in 2010 and $11.36 for 2011. These prices are from NAVFAC estimates. For the years after the 2011, the price is adjusted by 2.2% annually. This 1% above the project inflation rate.
- The installation of electrical energy generation systems at Miramar will reduce electrical costs, but payments to NAVFAC for distribution system maintenance are still required. NREL was unable to obtain detailed rate information from NAVFAC. However, discussions with NAVFAC and base personnel yielded estimates of this rate at $0.04 per kWh. An annual cost of $2,640,000 for NAVFAC services was estimated. This amount is increased each year by the inflation rate of 1.2%
    - SDG&E would likely require Miramar to pay standby and departing load charges for electrical service in the event Miramar's generation goes down. These charges were estimated at $6 per kW per month; assuming that Miramar would be required to pay these charges for the 2800 kW of fuel cell power and 1500 kW of solar power. These charges were estimated at $310,000 per year increasing at the rate of inflation of 1.2% annually. More information on SDG&E rate structures can be found by at www.sdge.com/regulatory/elec_misc.shtml.
- Miramar-initiated solar projects of approximately 2.3 MW would be eligible for net energy metering.
- The fuel cells would be interconnected under the California feed in tariff program. They are currently eligible for this program and the Public Utility commission has recently expanded the eligible generation size per customer premises to 3 MW from 1.5 MW. Under this program, the fuel cells would sell power under option B (described below).

To simplify the analysis, NREL assumed that 100% the power produced by the fuel cells would be used on base and that no additional power would be sold to SD&GE at the MPR rate.

- Option B (sale of excess) – Only the excess electricity produced and exported to SDG&E's electric system will be purchased at the MPR rate. Please see tariff/standard contract for the current MPR rate.[67]

- The escalation rate for the PPA contracts was assumed to be the same as the rate of inflation or 1.2%.
- The cost implications of fleet fuel switching were not analyzed.
- The results from this analysis illustrate that this set of energy project recommendations are likely viable under a 20-year project lifetime and would provide reduced energy costs to the base. The annual cost of the baseline scenario was compared to the annual cost of the recommended scenario over a 20-year period. The costs and savings for 2010-2015 are shown in Table 39.

Table 39. Costs of Recommended Scenario 2010 to 2015

	2010	2011	2012	2013	2014	2015
Base case Energy Cost	$11,072,162	$12,341,755	$12,613,274	$12,890,766	$13,174,362	$13,464,198
ESPC Payment		($1,122,835)	($2,245,671)	($2,295,465)	($2,346,360)	($2,398,379)
NAVFAC Payment		($817,354)	($2,640,000)	($2,671,680)	($2,703,740)	($2,736,185)
PPA Payments	$0	($1,495,000)	($5,775,880)	($5,812,191)	($5,848,937)	($5,886,124)
Cost of Grid Electrical Energy	($9,393,745)	($7,302,481)	($0)	($0)	($0)	($0)
Cost of pipeline natural gas	($1,489,881)	($1,461,634)	($1,128,228)	($784,773)	($802,038)	($819,683)
Electrical Standby and Departing load Charges		($150,000)	($310,000)	($313,720)	($319,994)	($326,394)
Capital from appropriations, ECIP, and ARRA	($14,306,667)	($21,133,333)				
Near Net Zero Energy Cost	($24,890,293)	($33,179,037)	($11,792,536)	($11,566,899)	($11,706,408)	($11,848,328)
Savings from near net zero	($13,818,131)	($20,837,282)	$820,738	$1,323,867	$1,467,954	$1,615,870

This table shows that there are no savings in 2010 or 2011 as the capital costs for the Miramar initiated projects are expended. In 2011, the base would make a pre performance period payment to the ESCO and start full repayment in 2012. Costs are included for the fuel cell and landfill gas PPA agreements. Payments were estimated to NAVFAC for utility service and SDG&E for standby and departing load charges. In 2012 the base begins to see savings from the energy project investment compared with the base case. Over the 20-year lifetime that was analyzed, the net savings after

[67] Feed-in Tariffs for Small Renewable Generation, SDGE, www.sdge.com/regulatory/AB1969.shtml. Accessed April 2010.

accounting for the capital costs are $26 million and the net present value is $6.7 million. The annual savings from this scenario are shown in Figure 68.

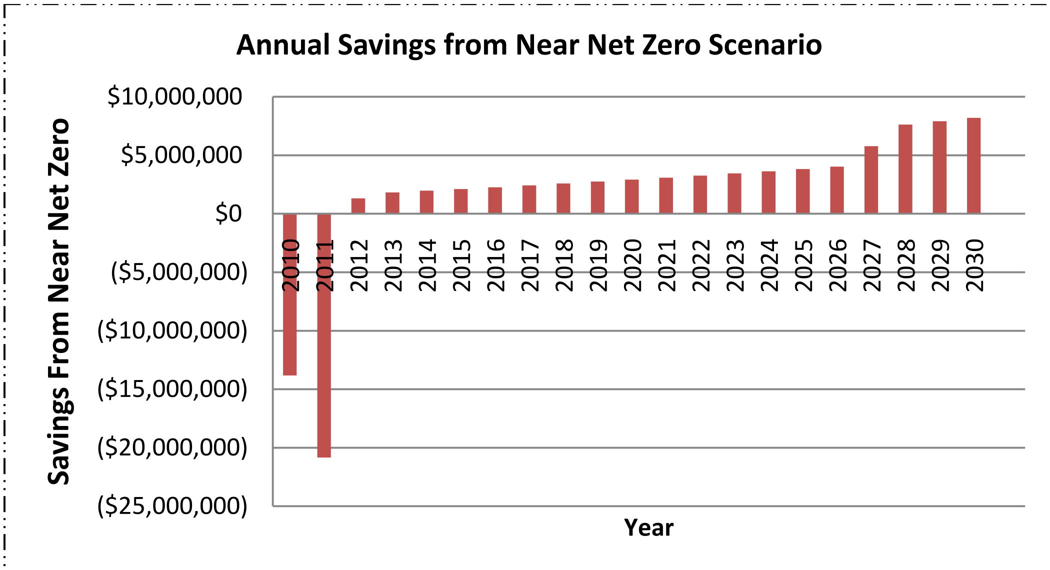


Figure 68. Annual estimated savings

The annual savings increase slightly every year between 2013 and 2026 because the escalation rate for the electrical energy from the PPA agreements was set at the inflation rate of 1.2%. The base case scenario has an annual increase of 2.2% for grid electricity and natural gas. This analysis is sensitive to this factor. When the price increase for grid based electrical energy drops below about 1.83%, the NPV value becomes negative. Additionally, in this scenario, the ESPC contract is paid off after the 16-year term, allowing for increased savings in 2027 and beyond. This analysis is also sensitive to several other estimated factors. For example, NAVFAC's previously estimated natural gas rates were $18.34 for 2010 and $17.95 for 2011. If these rates were used followed by an annual increase at the inflation rate of 1.2%, then the NPV increases to $11.9 million. Additionally the PPA price for the landfill gas project was projected to range between $0.09 and $0.13 per kWh. If the price drops to $0.09 the NPV is $13.4 million. If the price is raised to $0.13, the NPV is negative $25,000. This NPV represents the total system of energy projects (not just the landfill gas project or any other single project). Therefore because the fact that the landfill gas project at a price of $0.13 lowers the overall NPV does not prevent this individual project from being cost-effective at this price. These sensitivity analyses are intended to show that there are a number of variables that can affect the overall financial return. However, this financial analysis shows that under a variety of scenarios, the recommended energy projects will allow the base to move closer to NZEI status and will likely reduce costs for Miramar.

8.6 Conclusion

The analysis conducted by NREL shows that MCAS Miramar has the potential to make significant progress toward becoming a NZEI for its facilities and buildings. If the recommended energy projects and savings measures are implemented, then the base will achieve a 90% source Btu reduction. This will enable the base to set an example for other military installations, increase mission capabilities, provide environmental benefits, reduce costs, increase energy security, and exceed its energy goals and mandates.

The net zero analysis covered energy efficiency, renewable energy, the electric grid, and transportation. NREL has provided numerous recommendations to improve energy efficiency and expand renewable energy usage. These recommendations focus on the task force definition of a NZEI by concentrating the majority of the analysis on facilities and buildings. NREL did not develop recommendations to reduce tactical fuel use at Miramar, which will remain the largest category of energy use at the base.

MCAS Miramar has made significant progress through energy initiatives over the last several years. The base has the potential to expand on these efforts and maintain its leadership in military energy projects by implementing NREL's additional recommended energy projects.

Appendix A: Zero Energy Community Renewable Energy Supply Option Hierarchy[68]

Option Name and Number	ZEC Supply-Side Options	Examples
Option O *Demand reduction (a prerequisite for the renewable supply side options)*	**Buildings** Reduce site energy use through community design, setting targets for building energy efficiency and incorporating low-energy building technologies for new construction; for existing communities, making energy savings retrofits to buildings.	**Buildings** Influence energy demand reduction though urban design and lot layout, update and enforce building codes, setting energy-efficiency targets and density targets including both jobs and dwellings per acre. Buildings can incorporate aggressive energy efficiency and use daylighting, passive solar design, high-efficiency HVAC equipment, natural ventilation, evaporative cooling, ground-source heat pumps, ocean water cooling, etc.
	Transportation Reduce vehicle miles traveled for gasoline-powered passenger vehicles within the community and to and from the community. Provide convenient bus and/or rail stops for destinations to locations of employment outside the community.	**Transportation** Community design can include a diversity of land uses, densities, mix of housing and retail, and enhance walkability and connectivity within a community to minimize need for personal vehicles. Design can also create destinations within the community and minimize the distance to public transit. Maintain and operate vehicles to maximize efficiency; form car sharing clubs and other community-based initiatives; and provide and plan for bike lanes, alternative transportation and access to mass transit within the community.
	Community Infrastructure Assess loads for all sectors to define the biggest opportunities for energy savings and use energy-efficient strategies to minimize these loads.	**Community Infrastructure** Planning and installation can include LED traffic lights, high-efficiency pumps (for water pumping), data center upgrades, storm water management, district heating and cooling, reduced waste, etc.. Utilities are installing “smart grid” to provide user feedback regarding energy use and impact on their energy costs.
	Behavior Set community goals for energy and water use. Use policies, information and education, and incentives and disincentives within the community to achieve desired objectives.	**Behavior** Set aggressive energy-efficiency standards for all construction. Established policies and covenants can be used to incentivize building owners to use less energy and water. Through consumer education and feedback (metering, commissioning, retro-commissioning), consumers can be educated to turn lights and equipment off at night, metering, turn off vampire loads in buildings at night and when buildings are not occupied.

[68]Carlisle, N.; Van Geet, O.; Pless, S. (2009). *Definition of a 'Zero Net Energy' Community*. 20 pp.; NREL Report No. TP-7A2-46065. Golden, Colorado: National Renewable Energy Laboratory. (Note: This reference only addressed buildings.)

Option Name and Number	ZEC Supply-Side Options	Examples
Renewable Supply Options—Within Community		
Option 1 Use renewable energy systems in the community or campus within the built environment and on unusable Brownfield sites	**Buildings and Community Infrastructure** Use renewable energy sources on sites available within the built environment or on sites that are unbuildable such as Brownfield sites. This includes using solar on residential and commercial rooftops, parking structures, and along roadways. **Transportation** Provide transportation options powered by renewable energy available to all destinations within the community.	**Buildings** PV, solar hot water, ground-source heat pumps located on buildings, parking structures, along roadways and connected to building systems. For new construction, the design and layout of buildings should maximize rooftop area for renewable systems and the systems are either designed and installed on all new buildings or plumbed and wired to be added at a later date. For existing communities, maximize the amount of unshaded rooftop spaces with renewable systems that are determined to be cost-effective. It would also include the use of PV, wind, solar located on a Brownfield site within the community. **Transportation** Community residents and visitors can use alternatively fueled transportation, advanced vehicles and fuels. This option includes the installation of electric plugs in homes, public parking so that people can plug in electric or electric/hybrid vehicles at home or in public parking to power vehicles from renewable sources on buildings. It includes using electric-powered buses and shuttles within the community powered by renewable energy generated in the community. **Community Infrastructure** This option would also include generating and using methane from a wastewater treatment plant or producing power from waste as long as the energy is generated from waste streams generated within the community and processed in the community. Use renewable energy to power street lights, pumps, monitors, and meters.
Option 2a Renewable energy supply in the community Greenfield	**Buildings and Community Infrastructure** Build renewable energy sources on Greenfield sites located within the community boundaries. The renewable systems are connected to the electrical or distribution grid. **Transportation** Include the use of renewably generated electricity for cars, busses, and shuttles.	**Buildings** PV and wind located within the community boundary and connected to the grid. Central solar hot water connected to a distribution grid. Biofuel applications only if the fuel were grown in the community. **Transportation** Renewably generated electricity for cars, trucks, and busses. Ethanol or biofuels for transportation only in cases where the plants for the fuels are

Option Name and Number	ZEC Supply-Side Options	Examples
		grown in the community. **Community Infrastructure** Community scale microgrid connects distributed and community-scale renewable systems (electric and/or thermal energy) to buildings and utility grid. Storage may be added to the grid to power peak needs, night-time loads, or seasonal loads.
Off-Site Supply Options		
Option 2b Renewable energy originated offsite and imported to the community for use or further refinement	**Buildings** Use renewable energy sources available off-site to generate energy for use on a campus, a community or neighborhood.	**Buildings/Community Infrastructure** Biomass, wood pellets, waste residues, landfill gas or landfill gas can be imported from off site, which can be used on-site to generate electricity, heat or fuel. A community could also negotiate with its power provider to install dedicated wind turbines, PV or solar panels at a site with good solar/wind resources outside the community. In this approach, the community would own the hardware and receive credits for the power. The power company or a contractor would maintain the hardware.
	Transportation Use renewable-based fuels generated off-site for use on site.	**Transportation** Ethanol and biodiesel fueling stations located on site are included in this option. (Note for all cases in this category, the community should define acceptable distances for transport).
Option 3 Purchase new RECs	**Buildings/Transportation/Community Infrastructure** Purchase new off-site RECs that result in additional generation added to the grid.	**Buildings/Transportation/Community Infrastructure** Utility-based wind, PV, emissions credits, or other "green" purchasing options. Hydroelectric is sometimes considered. All off-site purchases must be shown to add new generation capacity to the grid. RECs could be used as a strategy to meet a goal for an interim period of time or as a "top off" strategy to provide, for example, the last 10% of renewable energy. It is important that an REC purchase add new generation capacity to the grid.

Appendix B: Renewable Energy Optimization Data

Scenario	Solar Vent Preheat Area (ft^2)	Solar Water Heating Area (ft^2)	Non-office Skylight/ Floor Area Ratio	Office Skylight/Floor Area Ratio	PV rating (kW)	Wind Capacity (kW)	Solar Thermal Area (ft^2)	Solar Thermal Electric (kW)	Biomass Gasifier Size (MBtu/hr	Biomass Gasifier Cogen Size (kW)	RE Case Life Cycle Cost ($)	Base case Life Cycle Cost ($)
Base Case												
No Restrictions	31,344	0	5.9%	2.5%	0	109,382	23,823	554	2.2	236	$118,978,857	$216,031,189
No: SVP	0	1	5.6%	2.2%	0	103,403	211,305	1,008	4.9	530	$125,664,978	$216,031,189
No: SVP, Wind	0	0	8.5%	2.3%	23,928	0	555,499	6,453	13.8	1,499	$230,672,098	$216,031,189
No: SVP, Wind, Solar Thermal	0	152,160	8.5%	4.5%	27,266	0	0	0	20.4	2,184	$259,027,123	$216,031,189
No: SVP, Wind, Solar Thermal, Daylighting	0	152,160	0.0%	0.0%	40,526	0	0	0	20.5	2,219	$314,972,987	$216,031,189
With Landfill Gas PPA												
No Restrictions	44,485	4,858	5.0%	2.2%	0	53,639	36,503	424	4.8	524	$76,731,971	$143,779,689
No: SVP	0	0	4.9%	2.0%	0	51,653	324,614	1,008	5.5	592	$88,436,625	$143,779,689
No: SVP, Wind	0	0	8.4%	3.6%	4,046	0	555,449	6,518	13.8	1,500	$116,543,015	$143,779,689
No: SVP, Wind, Solar Thermal	0	115,962	8.2%	5.6%	10,316	0	0	0	20.4	2,200	$151,389,044	$143,779,689

Scenario	Solar Vent Preheat Area (ft^2)	Solar Water Heating Area (ft^2)	Non-office Skylight/ Floor Area Ratio	Office Skylight/Floor Area Ratio	PV rating (kW)	Wind Capacity (kW)	Solar Thermal Area (ft^2)	Solar Thermal Electric (kW)	Biomass Gasifier Size (MBtu/hr	Biomass Gasifier Cogen Size (kW)	RE Case Life Cycle Cost ($)	Base case Life Cycle Cost ($)
No: SVP, Wind, Solar Thermal, Daylighting	0	115,967	0.0%	0.0%	23,724	0	0	0	20.3	2,204	$204,884,669	$143,779,689

Appendix C: Building Energy Data

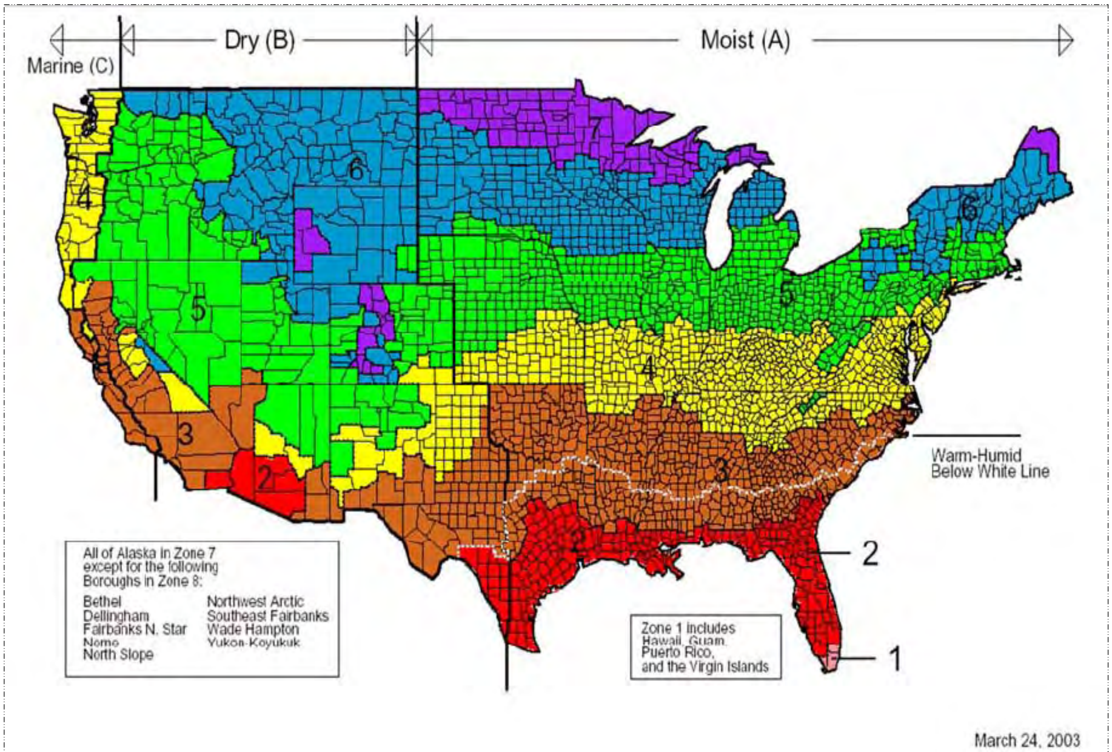


Figure 69. Climate zone designation

Table 40. EUI by Climate Zone

Base Scenario EUI by Subsectors and Climate Zones
IP Units (kBtu/ft^2·yr)

Subsector	Climate Zone														
	All	1A	2A	2B	3A	3B	3C	4A	4B	4C	5A	5B	6A	6B	7
All	70.7	82.3	67.6	72.8	77.6	57.8	62.2	70.4	55.3	55.8	74.9	64.4	75.8	73.5	74.0
Office/professional	57.4	55.4	60.6	64.5	52.2	46.3	43.9	59.7	57.9	53.0	60.4	47.8	61.9	61.1	67.5
Nonrefrigerated warehouse	41.0	27.2	30.6		36.8	30.3	21.8	42.1	49.4	29.6	47.3	50.5	49.5	47.4	45.3
Education	51.7	111.6	48.7	57.2	41.7	40.8	53.6	60.0	34.0	42.5	53.3	44.1	60.4	64.4	67.2
Retail (excluding mall)	67.7	52.3	66.0	82.5	63.2	54.4	52.2	68.4	57.5		72.6	70.8	75.9	90.8	100.0
Public assembly	61.6	75.4	65.5		72.1	52.3	46.1	53.9	47.8	76.6	68.1	49.7	65.8	51.3	70.0
Service	83.0	110.3	78.2		60.1	63.3	36.7	78.8	52.1		91.9	75.9	102.3	86.2	108.2
Religious worship	44.0		39.5		29.1	29.4		44.1	59.1		50.9	34.6	57.4	38.9	
Lodging	54.7	64.6	51.2		52.3	40.0		56.7	60.8	47.2	55.4	51.2	59.7	64.4	62.5
Food services	354.0	536.2	354.3		379.6	374.5	316.2	367.6		443.3	336.1	282.9	341.2	237.1	338.8
Health care (inpatient)	110.6	107.0	107.8	110.2	117.9	98.0	96.6	105.5	86.7		115.2	106.2	113.2	115.6	127.8
Public order and safety	67.4		54.0		61.2	70.9		60.2			78.2	77.6	73.0	87.1	
Food sales	181.3		200.3		189.7	150.6	154.1	188.4			173.4	181.8	208.3		164.2
Health care (outpatient)	75.9	65.4	79.8		64.0	79.2		65.9	68.3		89.9	55.4	81.9	78.4	107.4
Vacant	30.5		22.9	42.7	30.0	19.7	15.2	40.8	57.1	12.8	21.7	15.0	40.5		69.6
Other	57.5		72.8		42.0	43.5		57.0	31.9		60.8	42.2	62.8	65.1	43.7
Skilled nursing	131.4		132.0		113.4	102.3		145.3			141.9	105.8	132.2	131.9	
Laboratory	323.1				345.2	368.9		272.2			313.2		260.9	245.3	
Refrigerated warehouse	86.3							88.0			85.2	81.9	91.8		

Note: There are no CBECS buildings in climate zone 8.

Table 41. Building Details

Building Type	Number of Buildings	Total sq. ft.	% of Total	Average sq. ft.
Other	282	1,773,200	29.02%	6,288
Warehouse	50	1,084,432	17.75%	21,689
House	223	750,387	12.28%	3,365
Hangar	12	744,878	12.19%	62,073
Office	39	533,937	8.74%	13,691
Dwelling	74	424,032	6.94%	5,730
Garage	62	185,505	3.04%	2,992
Jail or Prison	4	151,213	2.47%	37,803
Magazine	17	79,491	1.30%	4,676
Medical Center	3	75,113	1.23%	25,038
Community Center	11	57,901	0.95%	5,264
Museum	2	44,104	0.72%	22,052
Fire House	4	36,299	0.59%	9,075
School	2	34,263	0.56%	17,131
Carport	5	29,649	0.49%	5,930
Theater	1	25,265	0.41%	25,265
Church	2	16,662	0.27%	8,331
Radio Facility	3	15,885	0.26%	5,295
Law Enforcement	4	13,218	0.22%	3,305
Heat Cool Plant	2	10,898	0.18%	5,449
Power Plant	9	6,003	0.10%	667
Water Plant	3	4,285	0.07%	1,428
Bunker	4	3,347	0.05%	837
Railroad Station	1	3,162	0.05%	3,162
Security	14	2,994	0.05%	214
Tower	5	2,598	0.04%	520
Shed	3	519	0.01%	173
Rain Shed	1	291	0.00%	291
Memorial	4	212	0.00%	53
Total	846	6,109,743		

Table 42. Building EUI Analysis

Building Type	# of Buildings	# with EUI	Total sq. ft. of building category	Total sq. ft. with an EUI	% of Total sq. ft. with an EUI	Average EUI
Other	282	63	1,773,200	952,457	53.71%	206
Warehouse	50	4	1,084,432	338,194	31.19%	19
House	223	134	750,387	433,833	57.81%	45
Hangar	12	5	744,878	452,495	60.75%	55
Office	39	15	533,937	337,156	63.15%	67
Dwelling	74	15	424,032	71,192	16.79%	252
Garage	62	2	185,505	117,063	63.11%	23
Magazine	17	1	79,491	25,644	32.26%	21
Medical Center	3	2	75,113	72,107	96.00%	138
Community Center	11	5	57,901	26,994	46.62%	683
Church	2	1	16,662	15,167	91.03%	170
Law Enforcement	4	1	13,218	6,256	47.33%	215
Heat Cool Plan	2	1	10,898	842	7.72%	4,355
Tower	5	1	2,598	1,248	48.04%	206

* Note the EUI values do not necessarily represent accurate values for a particular building category because several buildings often use common natural gas meters. For example, the dwelling numbers are much higher than actual consumption because the gas consumption for a multiple buildings is reflected on a single building. Additionally, only buildings with both natural gas and electrical data were included in this analysis, so if a building does not have a natural gas meter, it does not have a calculated EUI. Thus, averages for several categories are skewed upwards, as compared with their actual values.

Appendix D: Building Consumption Estimates

Natural Gas End Use Estimates

Base Building Category	Base ft²	Assumed Category	Heating	Cooling	Water heating	Cooking
			Values below are in kBtu per ft² per year			
Housing	1,174,419	Lodging	10.80	0	25.50	3.40
Hangar	744,878	Unrefrigerated Warehouse	2.20	0	0.20	-
Office	533,937	Office	8.00	0.3	2.20	0.30
Warehouse	1,084,432	Unrefrigerated Warehouse	2.20	-	0.20	0.30
Garage	185,505	Unrefrigerated Warehouse	2.20	-	0.20	-
Brig	151,213	Lodging	10.80	-	25.50	3.40
Other	2,235,360	Miscellaneous	5.40	0.50	10.90	0.90
	6,109,743	Total (kBtu)	35,091,853	1,277,861	59,746,654	7,004,482
		Total Btu = 103,120,850,565				

Electrical End Use Estimate

Base Building Category	Base Square Footage		Heat	Cool	Vent	Cooking	Refrig	Int. Ltg.	Ext. Ltg.	Office Equip	Misc
			Values below are in kWh per ft²								
Housing	1,174,419	Lodging	0.34	3.01	1.74	0.71	0.98	3.65	0.70	0.24	1.35
Hangar	744,878	Unrefrigerated Warehouse	0.04	0.34	0.15	0.01	0.26	3.23	0.30	0.23	0.40
Office	533,937	Office	0.19	3.53	2.28	0.11	0.46	4.36	0.92	2.66	0.65
Warehouse	1,084,432	Unrefrigerated Warehouse	0.04	0.34	0.15	0.01	0.26	3.23	0.30	0.23	0.40
Garage	185,505	Unrefrigerated Warehouse	0.04	0.34	0.15	0.01	0.26	3.23	0.30	0.23	0.40
Brig	151,213	Lodging	0.34	3.01	1.74	0.71	0.98	3.65	0.70	0.24	1.35
Other	2,235,360	Miscellaneous	0.07	1.38	0.74	0.25	0.90	2.42	1.05	0.29	0.99
	6,109,743	Totals (MWh)	789	9,645	5,480	1,579	4,080	19,084	4,371	2,850	5,156
		Total Btu = 181,005,246,245									

Appendix E: Energy Efficiency Calculations

Programmable Thermostat Savings Calculation

Products that earn the ENERGY STAR prevent greenhouse gas emissions by meeting strict energy efficiency guidelines set by the U.S. Environmental Protection Agency and the U.S. Department of Energy.
www.energystar.gov

CHANGE FOR THE BETTER WITH ENERGY STAR

Life Cycle Cost Estimate for
1 ENERGY STAR Qualified Programmable Thermostat(s)

This energy savings calculator was developed by the U.S. EPA and U.S. DOE and is provided for estimating purposes only. Actual energy savings may vary based on use and other factors.

Enter your own values in the gray boxes or use our default values.

Number of Units	1
Initial Cost per ENERGY STAR Unit (retail price)	$92
Initial Cost per Conventional Unit (retail price)	$0
Unit Fuel Cost (Cooling) ($/kWh)	$0.160
Unit Fuel Cost (Heating) ($/Therm)	$1.33

24 Hour Typical Usage Patterns*

	Weekday	Weekend
Nighttime Set-Back/Set-Up Hours	8	8
Daytime Set-Back/Set-Up Hours	10	10
Hours without Set-Back/Set-Up	6	6

Choose your city from the drop-down menu

City: CA-San Diego

Heating Season*

Typical Indoor Temperature w/o Set-Back	70
Nighttime Set-Back Temperature (Average)	62
Daytime Set-Back Temperature (Average)	62
Heating System Type	Gas Furnace

Cooling Season*

Typical Indoor Temperature w/o Set-Up	78
Nighttime Set-Up Temperature (Average)	82
Daytime Set-Up Temperature (Average)	85
Cooling System Type	Central AC

**All temperatures are in degrees Fahrenheit. Setpoint is defined as the temperature setting for any given time period. Set-back temperature is defined as the lower setpoint temperature for the energy-savings periods during the heating season, generally nighttime and daytime. Set-up temperature is defined as the higher setpoint temperature for the energy-savings periods during the cooling season, generally nighttime and daytime.*

Annual and Life Cycle Costs and Savings for 1 Programmable Thermostat(s)

	1 ENERGY STAR Unit(s)	1 Conventional Unit(s)	Savings with ENERGY STAR
Annual Energy Costs			
Heating Energy Cost	$178	$217	$39
Heating Energy Consumption (MBTU)	*13*	*16*	*3*
Cooling Energy Cost	$165	$221	$56
Cooling Energy Consumption (MBTU)	*3.5*	*4.7*	*1*
Total	**$343**	**$438**	**$96**
Life Cycle Costs			
Energy Costs	$3,812	$4,874	$1,062
Heating Energy Costs	*$1,979*	*$2,414*	*$435*
Heating Energy Consumption (MBTU)	201	245	44
Cooling Energy Costs	$1,833	$2,460	$627
Cooling Energy Consumption (MBTU)	53	71	18
Purchase Price for 1 Unit(s)	*$92*	*$0*	*-$92*
Total	**$3,904**	**$4,874**	**$970**
		Simple payback of initial cost (years)	**1.0**

Summary of Benefits for 1 Programmable Thermostat(s)

Initial cost difference	**$92**
Life cycle savings	**$1,062**
Net life cycle savings (life cycle savings - additional cost)	**$970**
Life cycle energy saved (MBTU)-includes both Heating and Cooling	**62**
Simple payback of additional cost (years)	**1.0**
Life cycle air pollution reduction (lbs of CO_2)	**10,451**
Air pollution reduction equivalence (number of cars removed from the road for a year)	**1**
Air pollution reduction equivalence (acres of forest)	**1**
Savings as a percent of retail price	**1054%**

Water Heater Set Point Change Calculation

Heat Rate Loss = Tank Surface Area * (Temp Hot Water – Temp Cold Water) / R-Value of Tank Insulation.

If we assume that the tank is 24.5 inches in diameters, 58 inches high, has an R value equal to 16, hot-water temperature equals 120°F and cold water temperature equals 60°F. The loss rate is 140.8 Btu/hr. If we assume that 5% of the units are unoccupied at any given time, this equals the equivalent of 27 units that are unoccupied year round. 140.8 Btu/hr*24 hours a day * 365 days per year * 27 units = 3.3 E 7 Btu = 33 MBtu.

Office Lighting Savings Calculations

Replacing 32W T-8s with 25W T-8s

Total Area	Assumed LPD (10% above eQUEST)	Total Wattage	Assumed % of Wattage that is Replace-able T-8s	Total Replace-able T-8 Wattage	32W-25W % Reduction	Total Wattage Reduction	Total % Reduction	Assumed Lighting Energy Use (30%) (kWh/yr)	Total Energy Savings (kWh)
533,937	1.2947	691,288	75.00%	518,466	21.88%	113,414	16.41%	1,863,900	305,796

Installing Occupancy Sensors

Total Electric Use	Total Assumed Lighting Energy Usage	% of Lighting that is Appropriate for Occupancy Sensors	Lighting Energy Use that is affected by Occupancy Sensors	Energy Savings based on Overall 10% Energy Use Reduction (kWh)	ASHRAE 90.1
6,213,000	1,863,900	80.00%	1,491,120	149,112	

Replacing T-8s and Installing Occupancy Sensors

Total Lighting Energy Use after T-8 Replacement	% of Lighting that is Appropriate for Occupancy Sensors	Lighting Energy Use that is affected by Occupancy Sensors	Energy Savings based on Overall 10% Energy Use Reduction	Total Combined Measure Savings (kWh)
1,558,104	80.00%	1,246,483	124,648	430,444

Appendix F: Federal and DoD Mandates

Federal Mandates

(Information adapted from DOE EERE FEMP Laws & Regulations, Energy Independence & Security Act, http://www1.eere.energy.gov/femp/regulations/eisa.html.)

Various legislation and an executive order require Federal agencies to reduce their natural resource consumption. This section presents a brief overview of the requirement for energy efficiency, renewable energy, water, advanced metering, and measurement.

Energy Efficiency

The Energy Independence and Security Act of 2007 mandates energy efficiency improvements relative to a 2003 baseline. The required reduction is 3% per fiscal year between FY 2006 and FY 2015. The total reduction relative to the 2003 baseline should be 30%.

Water Conservation

Executive Order (E.O.) 13423 mandates a reduction in water consumption intensity (gallon/square foot) relative to a 2007 baseline. The required reduction is 2% per fiscal year between FY 2008 and FY 2015. The total reduction relative to the 2007 baseline should be by 16%.

Renewable Energy

EPAct 2005 mandates renewable usage in Federal facilities according to the following schedule: not less than 3% in FY 2007 to FY 2009, not less than 5% in FY 2010 to FY 2012, and not less than 7.5% in FY 2013 and thereafter.

E.O. 13423 mandates that at least half of renewable energy used by the Federal Government must come from new renewable sources (in service after January 1, 1999).

EISA 2007 requires 30% of the hot water demand in new Federal buildings (and major renovations) to be met with solar hot water equipment, provided it is life-cycle cost-effective.

Advanced Metering

EPAct 2005 requires all Federal buildings to be metered by October 1, 2012. Advanced meters or metering devices must provide data at least daily and measure the consumption of electricity at least hourly.

Measurement

EISA 2007 requires agencies to identify all "covered facilities" that constitute at least 75% of the facility energy use. An energy manager must be designated for each of these covered facilities. It also requires completing comprehensive energy and water evaluations of 25% of covered facilities each year, so that an evaluation of each facility is completed at least once every four years. Finally, agencies are required to use applications to benchmark buildings and track progress.

Vehicle

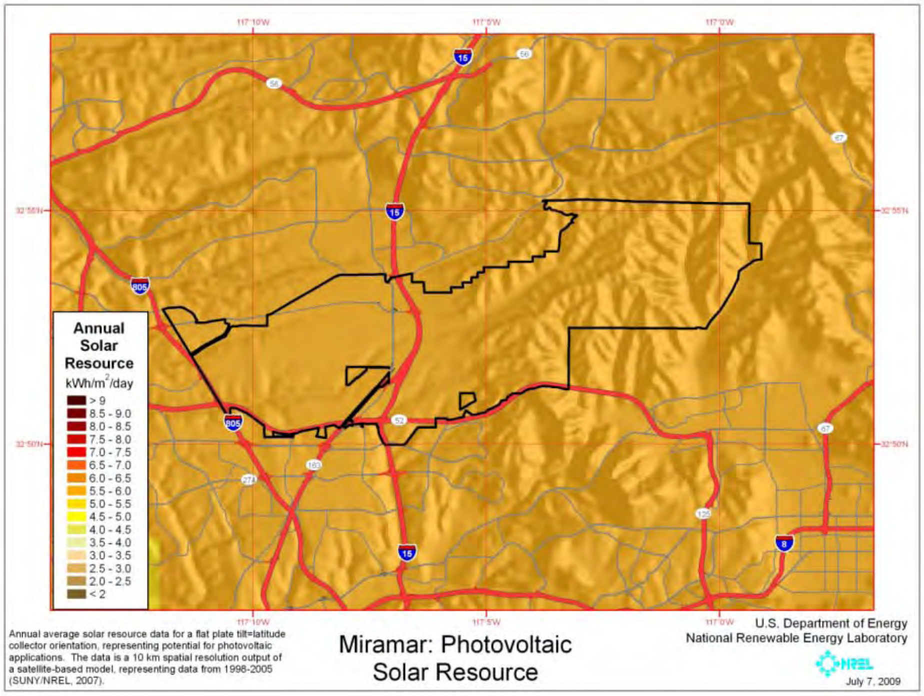
There are several Federal mandates that relate to fleet vehicle petroleum reduction and alternative fuel use. Federal agencies are required to achieve at least a 20% reduction in annual petroleum consumption and a 10% increase in annual alternative fuel consumption by 2015 from a 2005 baseline. Also, each agency must install at least one renewable fuel pump at each Federal fleet fueling center by 2010.

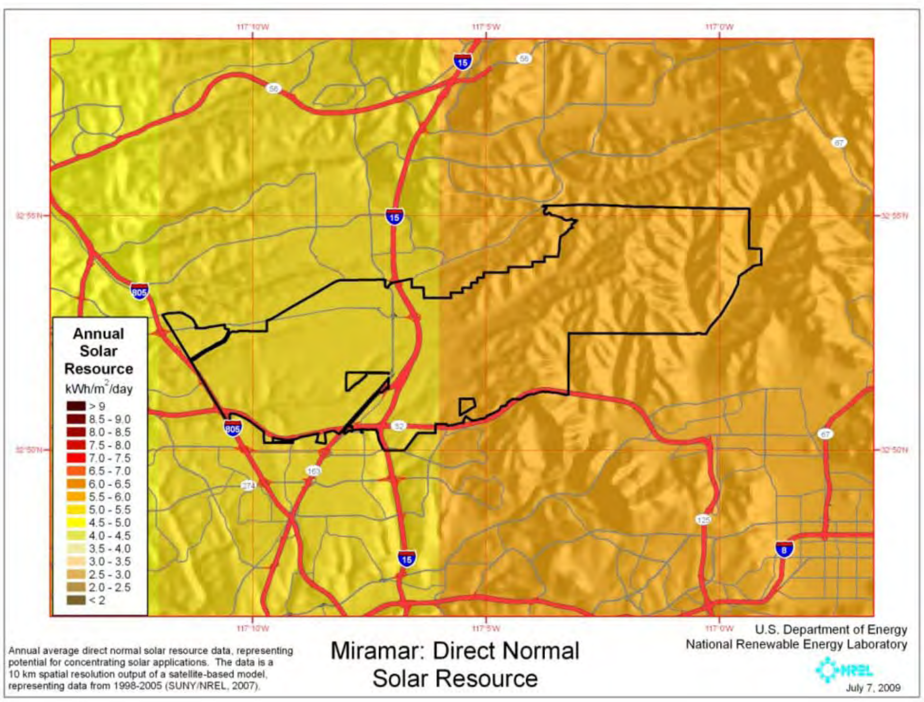
DoD Mandates

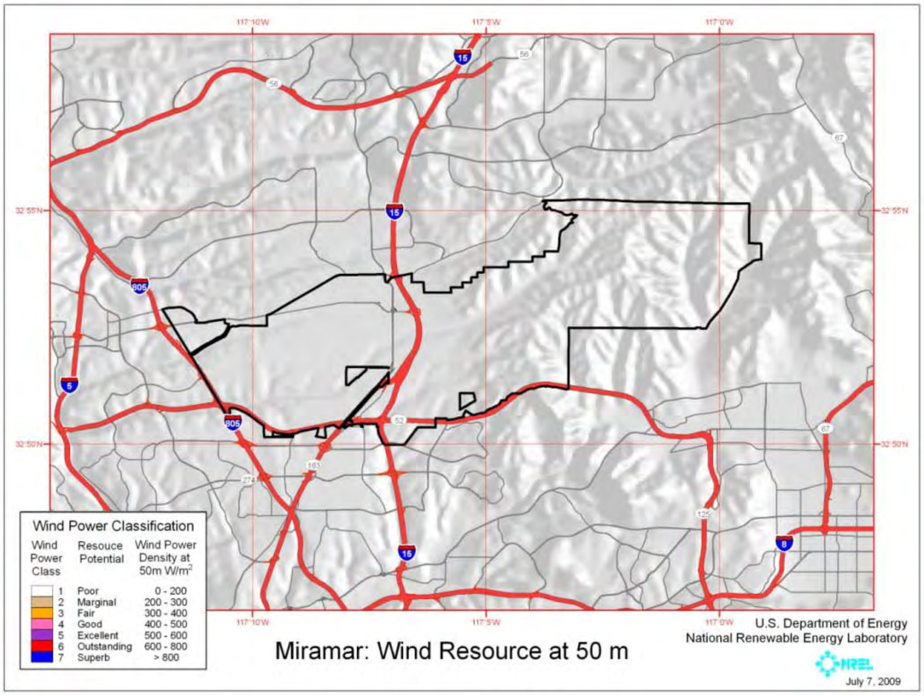
Renewable Energy. The National Defense Authorization Act of 2007 requires the DoD to generate 25% of its electricity from renewable sources by 2025.[69]

[69] Renewable Energy. Army Energy Program, http://army-energy.hqda.pentagon.mil/renewable/renewable.asp. Accessed 9-15-09.

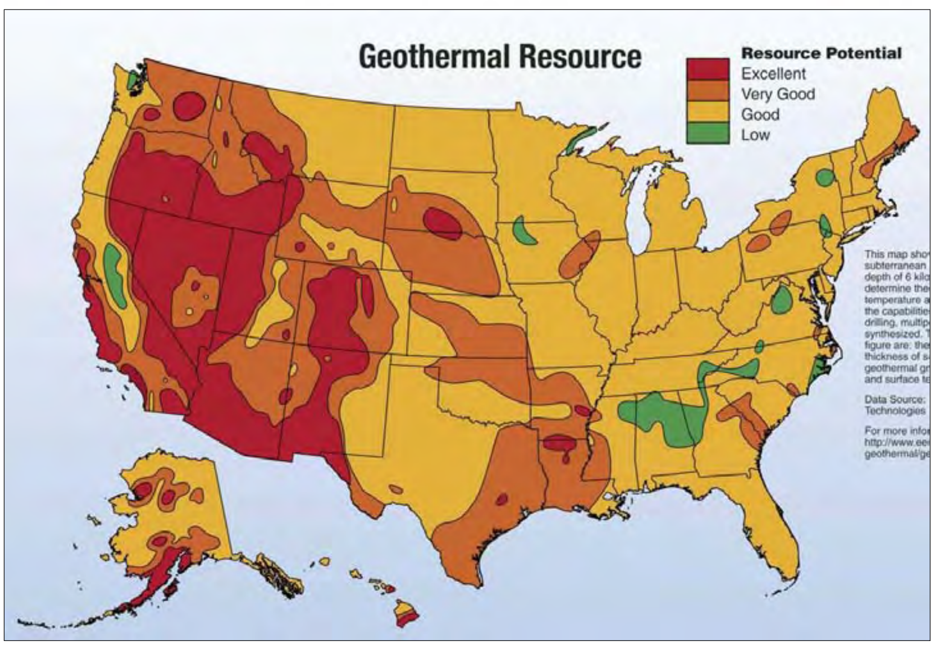
Appendix G: Renewable Energy Resource Maps



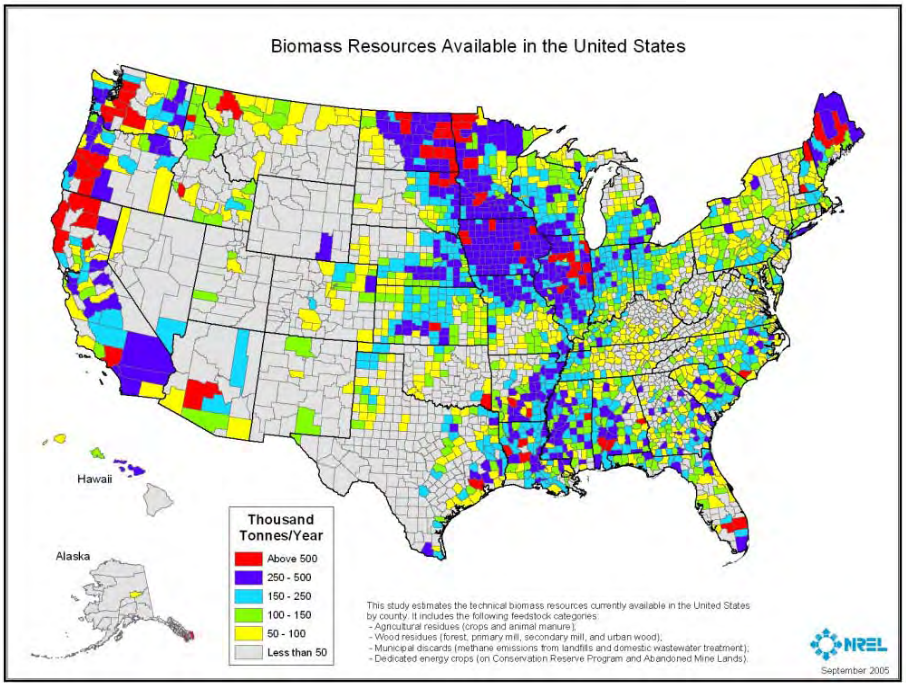




Wind Power Classification
Wind Power Class
Resouce Potential
Wind Power Density at 50m W/m2
1 Poor 0 - 200
2 Marginal 200 - 300
3 Fair 300 - 400
4 Good 400 - 500
5 Excellent 500 - 600
6 Outstanding 600 - 800
7 Superb > 800
Miramar: Wind Resource at 50 m
U.S. Department of Energy
National Renewable Energy Laboratory
July 7, 2009



Geothermal Resource
Resource Potential
Excellent
Very Good
Good
Low


Biomass Resources Available in the United States
Hawaii
Alaska
Thousand Tonnes/Year
Above 500
250 - 500
150 - 250
100 - 150
50 - 100
Less than 50
This study estimates the technical biomass resources currently available in the United States by county. It includes the following feedstock categories:
- Agricultural residues (crops and animal manure);
- Wood residues (forest, primary mill, secondary mill, and urban wood);
- Municipal discards (methane emissions from landfills and domestic wastewater treatment);
- Dedicated energy crops (on Conservation Reserve Program and Abandoned Mine Lands).
NREL
September 2005

Appendix H: Photovoltaic Potential

Background

PV Array. The PV array is the primary component of a PV system, which converts sunlight to electrical energy; all other components simply condition or control energy use. Most PV arrays consist of interconnected PV modules that range in size from 50 to 300 peak watts. Peak watts are the rated output of PV modules at standard operating conditions of 25°C (77°F) and insolation of 1,000 W/m2. Because these standard operating conditions are nearly ideal, the actual output will be less under typical environmental conditions most of the time. PV modules are the most reliable components in any PV system. They have been engineered to withstand extreme temperatures, severe winds, and impacts. ASTM E 1038-93 subjects modules to impacts from one-inch hail balls at terminal velocity (55 mph) at various parts of the module. PV modules have a life expectancy of 20 to 30 years and manufacturers warranty them against power degradation for 25 years. The array is usually the most expensive component of a PV system; it accounts for approximately two-thirds the cost of a grid-connected system. There is large choice of PV manufacturers and it is recommended that the PV be approved by Go Solar California.[70]

Inverters. PV arrays provide direct current (DC) power at a voltage depending on the configuration of the array. This power is converted to alternating current (AC) at the required voltage and number of phases by the inverter. Inverters enable the operation of commonly used equipment such as appliances, computers, office equipment and motors. Current inverter technology provides true sine wave power at a quality often better than that of the serving utility.

There are inverters available that include most or all of the control systems required for operation including some metering and data-logging capability. Inverters must provide several operational and safety functions for interconnection with the utility system. The Institute of Electrical and Electronic Engineers, Inc. (IEEE) maintains standard "P929 Recommended Practice for Utility Interface of Photovoltaic (PV) Systems," which allows manufacturers to write "Utility-Interactive" on the listing label if an inverter meets the requirements of frequency and voltage limits, power quality, and non-islanding inverter testing. Underwriters Laboratory maintains "UL Standard 1741, Standard for Static Inverters and Charge Controllers for Use in Photovoltaic Power Systems," which incorporates the testing required by IEEE 929 and includes design (type) testing and production testing. There is a large choice of inverter manufacturers; although, it is recommended that the inverter be approved by Go Solar California.[71]

Operation and Maintenance (O&M).

The PV panels will come with a 25-year performance warranty; the inverters come standard with a five or ten-year warranty (extended warranties are available) and is expected to last 10 to 15 years. System performance should be verified on a vendor-provided Web site. Wire and rack connections should be checked. For this economic analysis, an annual O&M cost of 0.17% of total installed cost is used, based on O&M cost of other fixed axis grid-tied PV systems. For the case of single axis

[70] List of Eligible SB1 Guidelines Compliant Photovoltaic Modules, Go Solar California, http://www.gosolarcalifornia.org/equipment/pv_modules.php. Accessed April 2010.
[71] List of Eligible Inverters, Go Solar California, www.gosolarcalifornia.org/equipment/inverters.php. Accessed April 2010.

tracking, an annual O&M cost of 0.17% of total installed cost is used based on existing O&M costs of fixed axis PV systems.

PV Size and Performance. The PV arrays must be installed in unshaded locations on the ground or on building roofs that have an expected life of at least 25 years. The predicted array performance was found using PV Watts, a performance calculator for grid Connected PV system created by NREL's Renewable Resources Data Center.[72]

When the system goes out to bid, a design-build contract should be issued requesting the best performance (kWh/yr) at the best price with least roof penetrations for roof-mounted systems and let the vendors optimize system configuration including slope. PV systems that produce more kWh/yr per land or roof area should be scored higher.

PV Carport. For area-constrained locations, carport PV systems can be implemented to increase the amount of PV on the site without using additional land area. The carport PV systems are more expensive than ground-mounted or roof-mounted systems, but provide two benefits: electricity generation and shade structures for vehicles. Carport PV is typically installed only over the parking space, not the rows in between. It is assumed that this will be the design at Miramar because it maximizes the number of spaces that can be covered with existing funding. For this study, a power density of 10 W/ ft^2 (100 ft^2/kW) is used for carport PV over the parking spaces. The PV should be flat or slightly tilted for water drainage. It is assumed for this study that carport PV will have 0 slope and cost $7.50/W(DC). The annual output for zero degree fixed tilt is about 1,260 kWh/kW. The carport PV should be at least nine feet clear in all locations. Carport design should drain water to the south side to minimize water dripping on car and to minimize water freezing on the parking lot in shade areas. Gutters could be installed along south edge if desired.

PIX # 12373

Figure 70. Carport PV at Coronado Island, CA (Courtesy of SunPower)

[72] A Performance Calculator for Grid-Connected PV Systems, PV Watts, Go Solar, http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/. Accessed April 2010.

Figure 71. Parking area in front of Building 9670-Miramar (Courtesy of MCAS Miramar)

PV Rooftop. In many cases, the roof is the best location for a PV system. Roof-mounted PV systems are more expensive than ground- mounted systems, but this is an ideal location because it is out of the way and usually unshaded. Large areas with minimal rooftop equipment are preferred, but equipment can sometimes be worked around if necessary. If a building has a sloped roof, flush mounted plates can fit approximately 11 W/ ft^2 of capacity. If the building roof is flat, ballast or rack mounted systems can fit approximately 8 W/ ft^2 of capacity. For flat roofs, only open areas on the south side of roof obstructions are preferred. Typically, PV panels are installed on roofs that are less than five years old. It is assumed for this study that roof-mounted PV will be sloped at 10 degrees with a power density of 8 W/ ft^2 and cost $6.00/W(DC). The annual output for 10 degree fixed tilt is about 1,400 kWh/kW.

Figure 72. Roof area of Commissary and Exchange (Courtesy of MCAS Miramar)

PV Ground Mount. Ground-mounted PV is the lowest cost area to mount PV systems. There are several mounting options available, each having different benefits for different ground conditions. Ground-mounted PV systems require about 6 acres/MW for 10 degree fixed tilt and 7 acres/MW for zero tilt single axis tracking PV. The annual output for 20 degree fixed tilt is about 1,400 kWh/kW (233 MWh/acre) and for zero tilt single axis tracking about 1,700 MWh/MW (243 MWh/acre). The estimated cost for this project for 10 degree fixed tilt is $5/W(DC). For this study, it is assumed that systems are all fixed mount.

In order to get the most out of the ground area available, it is important to consider whether the site layout can be improved to better incorporate a solar system. If there are unused structures, fences, trees, or electrical poles that can be removed, the unshaded area can be increased to incorporate more PV panels. When considering a ground-mounted system, an electrical tie-in location should be identified to determine how the energy will be fed back into the grid.

PIX # 17749

Figure 73. 720 kW Single axis tracking system at NREL (Credit: Patrick Corkery, NREL)

Appendix I: Concentrating Solar Power Analysis

Background

Process steam needs are unclear, but have been estimated based on proposed replacement of existing boilers. There are two boilers in Building 4312 that are 3,350,000 Btu/hr (1.0 MW) and one in Building 4325 that is 1,760,000 Btu/hr (0.5 MW).

Analysis

Examination of the load duration curve for the site suggested 10 MW would meet approximately 92% of the Miramar load on an hourly basis. The modeling was performed at this capacity.

- Solar data for the load-data period are not available, so TMY data were used for the analysis. The climate file for San Diego-Miramar NAS, California was downloaded from the EnergyPlus Web site.
- The CSP analysis looked at four different technology configurations:
  - Dish/Stirling engine (no storage)
  - North-south oriented Parabolic Troughs with no storage
  - North-south oriented Parabolic Troughs with storage
  - East-west oriented Parabolic Troughs with storage

Systems with storage were sized with a net turbine capacity of 10 MW. Storage hours were selected that gave a minimum LCOE optimum while approximately meeting the observed average daily load on a monthly basis.

Solar Advisor Model (SAM) version 2009-8-27 was used for the analysis.

Results

The load duration curve and average daily load are shown in Figure 74. Weekly variations are apparent, as is a slight seasonal fluctuation. The highest loads occur in June through September.

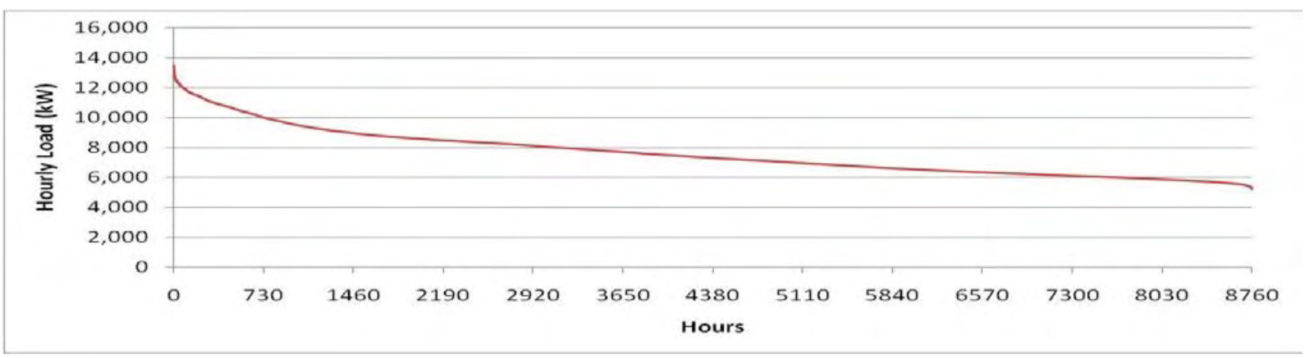


Figure 74. Load duration curve

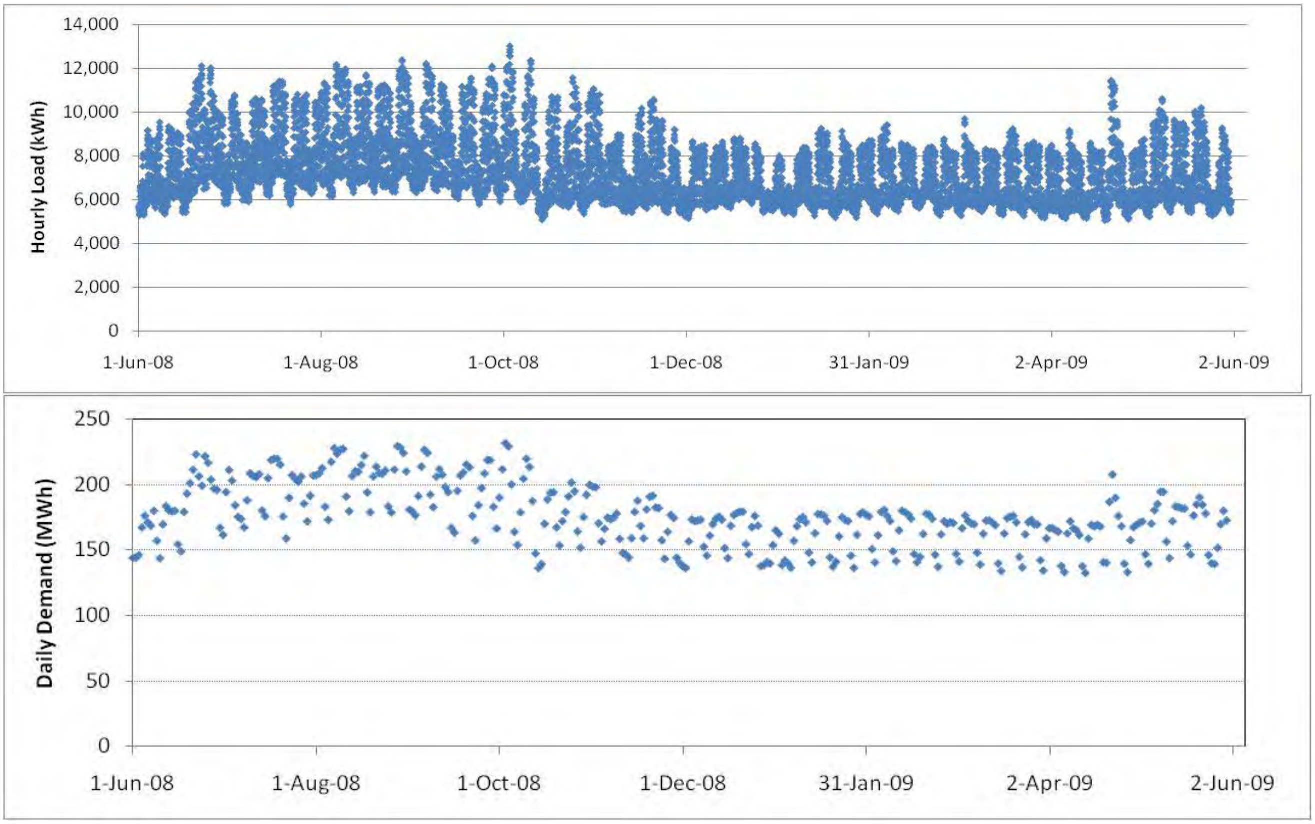


Figure 75. Average hourly load (top) and average daily load (bottom) for Miramar NAS

Dish/Engine CSP

Consultation with Chuck Andraka of Sandia National Labs indicated that a 10 MW system size is smaller than dish/engine system developer SES believes to be cost-effective for deployment. SES recently announced a contract for a 27 MW system in Texas. Infinia produces smaller dish/engine sets and may be a more suitable vendor for this scale. Nonetheless, an SES design was modeled because this is the system model available within SAM. While performance can be predicted using the SAM code, cost data for dish/engine systems are not well known and contact with a vendor is recommended. Dish/engine systems do not incorporate TES and do not require cooling water. The 10 MW system consists of 400 25-kWe dishes.

Parabolic Trough CSP

Trough systems are the most mature CSP technology and cost information is relatively well known. Traditionally, troughs are oriented along a north-south axis because this layout generates the greatest amount of energy over the course of a year. However, such a layout exhibits 2 to 3 times variation between summer and winter average daily energy output. If less seasonal variation or high capacity factors are desired, an east-west orientation may be preferred.

Parabolic trough plants can incorporate TES by storing the heat transfer fluid or a dedicated thermal storage fluid at high temperature for later use. For this analysis, Trough with TES configurations were assumed for both north-south and east-west field orientations. The TES was assumed to be a two-tank molten salt design, similar to that running at the 50 MW Andasol-1 plant in Spain. The field and TES size were selected to minimize LCOE and avoid energy dumping. Storage was also capped at 18 hours full-load capacity to avoid excessive pumping losses for the large solar field. The four different CSP configurations are outlined in Table 43.

Table 43. CSP Plant Assumptions and the Resulting Costs

Parameter	Case 1 6 MW Dish/Engine	Case 2 6 MWTroughw/o TES	Case 3 6 MW Trough 12-hr TES	Case 4 6 MW Trough 15-hr TES
Solar Field Aperture (m2)	21,000	49,000	111,000	139,000
Plant Footprint (acres)	14	37	85	105
Orientation	--	North-South	North-South	East-West
Annual Power Gen (MWh)	9,700	12,800	26,000	30,700
Annual Capacity Factor	19%	24%	49%	58%
LCOE (nominal)[1]	n/a[2]	\$0.22/kWh	\$0.24/kWh	\$0.26/kWh
Est. installed Cost	n/a[2]	\$34M	\$83M	\$106M
Thermal Storage (hrs)	0	0	12 (256 MWh-t)	15 (324 MWh-t)

[1] Assumes 30% investment tax credit.
[2] Accurate estimate not available, vendor quotes are recommended.

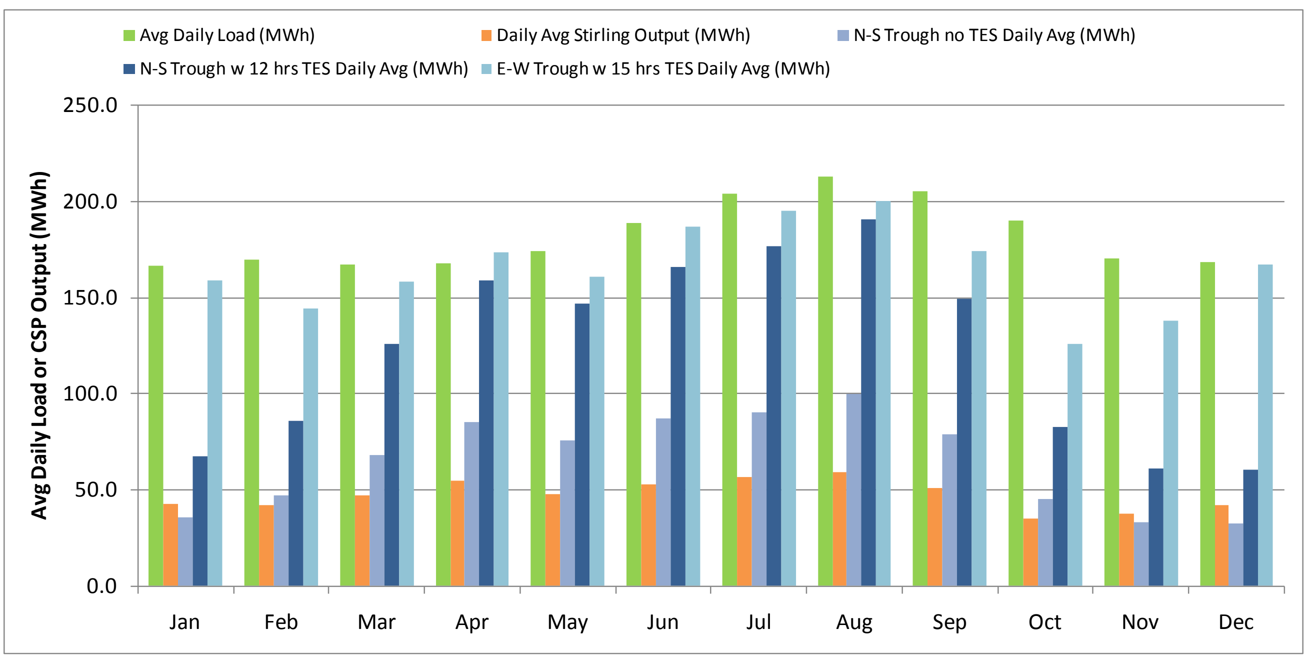


Figure 76. Average daily load and average daily CSP electricity generation for each month

Appendix J: Greenhouse Gas Inventory

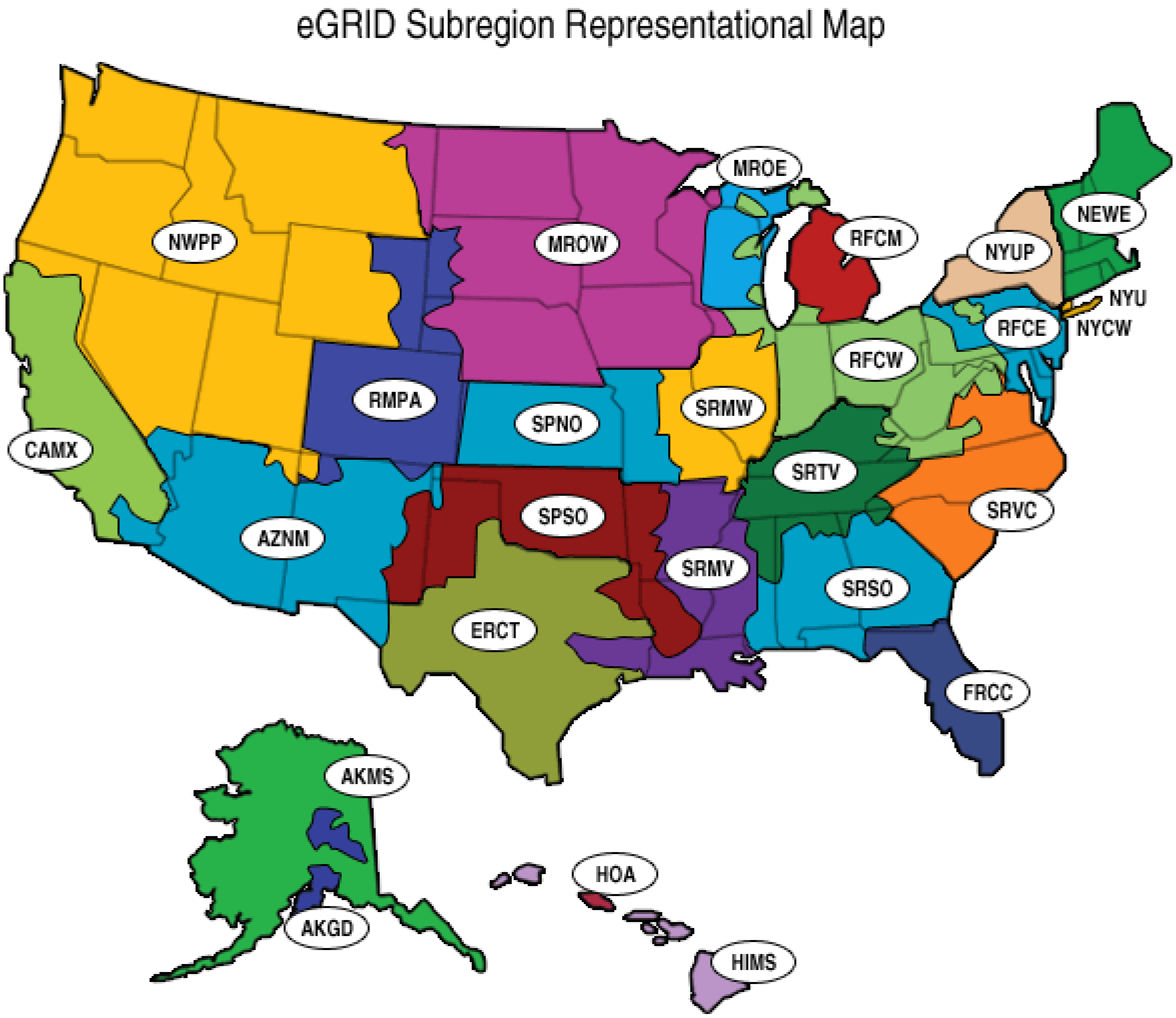


Figure 77. EPA's eGRID sub-region map

Table 44. Emission Factors used in GHG Calculations for Miramar

Emission factors for Miramar's electricity usage

	CO_2 Emission Factor (lb/kWh)	CH_4 Emission Factor (lbs/kWh)	N2O Emission Factor (lb/kWh)
CA - CAMX-California	0.72412	0.00003024	0.00000808

Emission factors for Miramar's natural gas usage (see Note 2).

	CO_2 Emission Factor (kg CO_2/MBtu)	CH_4 Emission Factor (kg/MBtu)	N2O Emission Factor (kg/MBtu)
Natural gas, commercial	53.06	0.005	0.0001

Emission factors for Miramar's propane usage

	CO_2 Emission Factor (kg CO_2/MBtu)	CH_4 Emission Factor (kg/MBtu)	N_2O Emission Factor (kg/MBtu)
Petroleum, propane	63.07	0.011	0.0006

Emission factors for Miramar's diesel usage

	CO_2 Emission Factor (kg CO_2/MBtu)	CH_4 Emission Factor (kg/MBtu)	N_2O Emission Factor (kg/MBtu)
Petroleum, distillate fuel oil (#1, 2, & 4)	73.15	0.011	0.0006

Emission factors for Miramar's mobile sources

	CO_2 Emission Factor (kg CO_2/gal)	CH_4 Emission Factor (kg/gal)	N_2O Emission Factor (kg/gal)
Diesel, gallons	10.15	-	-
Gasoline, gallons	8.81	-	-
Ethanol (E85), gallons	5.56	-	-
Biodiesel, gallons	9.46	-	-
	CO_2 Emission Factor (kg CO_2/scf)	CH_4 Emission Factor (kg/scf)	N_2O Emission Factor (kg/scf)
CNG, standard cubic feet	0.054	-	-

Appendix K: Small Generation Interconnection Study Process[73]

- Project is larger than 2 MW, but no larger than 20 MW, is not certified, or is certified by did not pass Fast Track or 10 kW Inverter Processes.
- ISO notifies IC of IR, documentation of site control, and $1,000 deposit receipt (3 BD).
- ISO notifies IC IR is complete or incomplete (10 BD).
- IC to provide information listed on incomplete notification or request extension of time to provide information (10 BD).

Scoping Meeting held once IR deemed complete. (10 BD) Purpose is to assemble appropriate personnel resources required to accomplish meeting purposes. Purpose of meeting is to: (a) discuss IR and review existing studies relevant to IR, (b) determine which study (Feasibility, System Impact, Facilities) or if IA will initiate the process.

- **5 BD after Scoping Meeting -** Interconnection points required from IC
- **ISO** prepares scoping meeting minutes

Feasibility Study

- **5 BD -** ISO to provide Feasibility Study Agreement including outline of scope of study and non-binding good faith estimate of cost to perform the study.
- **15 BD –** IC executes and returns the Feasibility Study Agreement and study deposit (lesser of 50% of estimated cost or $1,000) (FSA)
- 30 BD – ISO issues the final (IFS) report issued to IC

System Impact Study

- **5 BD -** ISO to provide System Impact Study Agreement including outline of scope of study and non-binding good faith estimate of cost to perform study
- **30 BD –** IC executes and returns the System Impact Study Agreement and study deposit (**50%** of good faith estimate)
- **45 BD – ISO** issues the final (**SIS**) report to **IC**

Facilities Study

- **5 BD -** ISO sends IC a **Facilities Study Agreement** including outline of scope of study and non-binding good faith estimate of cost to perform study, or PTO sends an executable IA
- **30 BD –** IC returns executed **Facilities Study Agreement** and study deposit (**full amount** of good faith estimate)
- **30 BD –** If **No** network upgrades are required **ISO** issues the final (**SIS**) report to **IC**

[73] "SGIP Study Process", San Diego Gas and Electric. www.sdge.com/documents/rfo/renewable2009/SGIPStudyProcess.doc . Accessed April 2010.

- **45 BD –** If network upgrades are required **ISO** issues the final (**SIS**) report to **IC**
- **SGIA** - When Facilities Study is complete
- **30 BD –** The IC shall (a) agree to pay for identified Interconnection Facilities and upgrades and request IA from PTO, (b) withdraw IR, or (c) request IA from PTO despite disagreement with costs in Facilities Study and request SGIA be filed unilaterally at FERC**.**
- **5 BD –** PTO will provide IC and executable SGIA
- Prior to SGIA execution, IC may request an E&P Agreement authorizing PTO to begin engineering and procurement of long lead-time items. This is optional and will not alter IC's Queue Position or In-Service Date.

Appendix L: Energy Savings Performance Contract Information

ESPC Awarded Delivery Order Summary[74]

Super ESPC Awarded Delivery Orders Summary						
	Project Count	Project Investment	Contract Price	Guaranteed Cost Savings	Annual Energy Savings (btu x 10^6)	Cumulative Energy Savings (btu x 10^6)
Total for FY 1998	5	$6,602,089	$15,018,137	$17,188,639	60,445	776,436
Total for FY 1999	15	$40,934,613	$94,431,913	$95,513,705	341,577	5,674,617
Total for FY 2000	20	$62,055,135	$135,619,538	$136,639,714	608,829	9,646,303
Total for FY 2001	31	$121,285,179	$276,057,256	$272,624,512	967,045	16,127,153
Total for FY 2002	19	$96,939,177	$313,744,546	$314,251,107	746,512	14,681,373
Total for FY 2003	39	$251,765,121	$543,487,546	$553,366,482	2,543,679	37,598,482
Total for FY 2004	6	$22,319,540	$52,330,073	$54,835,685	297,604	5,265,492
Total for FY 2005	9	$72,184,223	$198,707,333	$199,154,538	572,942	11,585,328
Total for FY 2006	22	$164,351,251	$413,254,189	$418,288,341	1,563,314	29,742,698
Total for FY 2007	15	$144,385,872	$353,891,202	$358,500,477	883,927	15,076,912
Total for FY 2008	21	$300,277,400	$698,335,081	$709,224,332	1,808,803	31,937,790
Total for FY 2009	23	$432,772,218	$1,298,639,802	$1,461,042,967	4,496,632	84,977,403
Grand Total	**225**	**$1,715,871,818**	**$4,393,516,616**	**$4,590,630,499**	**14,891,309**	**263,089,988**

[74] Federal Energy Management Program. Super ESPC Awarded Delivery Orders Summary. DOE Awarded Task Order Report. Awarded Energy Service Performance Contacts, www.eere.energy.gov/femp/pdfs/do_awardedcontracts.pdf. Accessed 8-24-09.

ESPC versus Appropriations Costs[75]

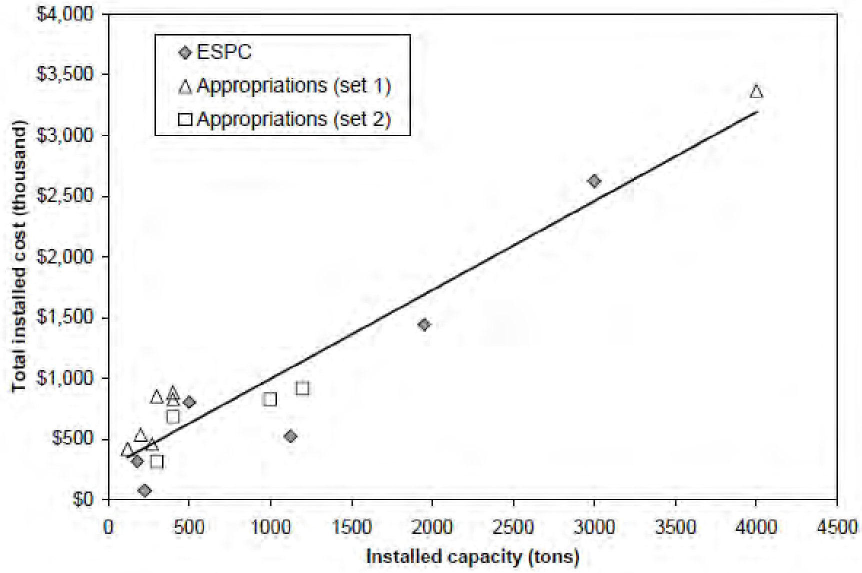


Figure 78. Chiller ECMs: design completion and construction costs in appropriations-funded projects (including appropriations set 2) and implementation price in ESPC projects

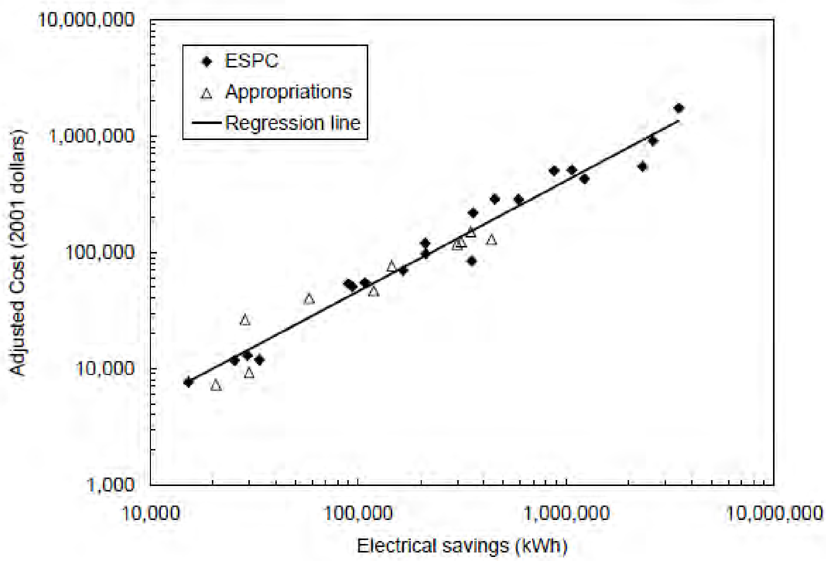


Figure 79. Lighting ECMs: design completion and construction costs in appropriation-funded projects and implementation price in ESPC projects

[75] Hughes, P.J.; Shonder, J.A.; Sharp, T.; Madgett, M. Evaluation of Federal Energy Savings Performance Contracting-Methodology for Comparing Processes and Costs of ESPC and Appropriations Funded Energy Projects. ORNL/TM-2002/150. Oak Ridge, Tennessee: Oak Ridge National Laboratory. 2003.

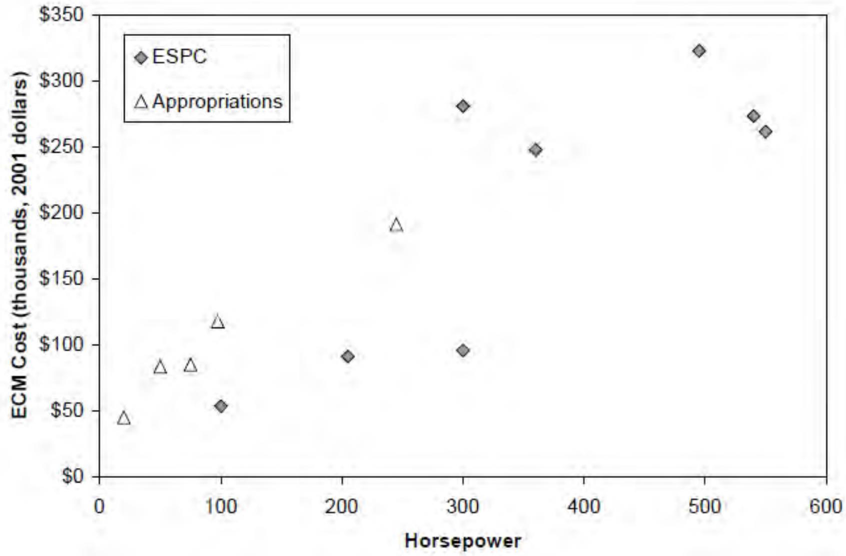


Figure 80. Variable-frequency-drive ECMs: design completion and construction costs in appropriations-funded projects and implementation price in ESPC projects

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14. ABSTRACT *(Maximum 200 Words)*
The U.S. Department of Defense (DoD) is the largest energy consumer in the U.S. government. Present energy use impacts DoD global operations by constraining freedom of action and self-sufficiency, demanding enormous economic resources, and putting many lives at risk in logistics support for deployed environments. There are many opportunities for DoD to more effectively meet energy requirements through a combination of human actions, energy efficiency technologies, and renewable energy resources. In 2008, a joint initiative was formed between DoD and the U.S. Department of Energy (DOE) to address military energy use. This initiative created a task force comprised of representatives from each branch of the military, the Office of the Secretary of Defense (OSD), the Federal Energy Management Program (FEMP), and the National Renewable Energy Laboratory (NREL) to examine the potential for ultra high efficiency military installations. This report presents an assessment of Marine Corps Air Station (MCAS) Miramar, selected by the task force as the initial prototype installation based on its strong history of energy advocacy and extensive track record of successful energy projects.

15. SUBJECT TERMS
U.S. Department of Defense; DoD; energy self-sufficiency; U.S. Department of Energy; DOE; military energy use; net zero energy analysis; ultra high efficiency military installations; energy efficiency technology, renewable energy resources; National Renewable Energy Laboratory; NREL; Marine Corps Air Station Miramar; MCAS

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Navy Nears Power Deal to Help Avoid Calif. Blackouts

April 30, 2012

Associated Press | by Michael R. Blood

LOS ANGELES -- The U.S. Navy is nearing a first-time agreement to curb electricity use at its sprawling San Diego-area bases if power runs short in Southern California this summer, a deal intended to diminish the threat of blackouts while the troubled San Onofre nuclear plant remains offline.

The Navy is San Diego Gas & Electric's largest customer, and the utility has been working on an agreement under which the Navy would temporarily reduce its energy consumption if regional supplies get scarce. In exchange, the Navy would receive a break on electricity rates.

The company has similar agreements with large industrial customers, which can slash the demand for power at critical times and keep the lights burning.

State energy officials say Southern California could be hit by rotating blackouts this summer if a heat wave hits while San Onofre's twin reactors remain dark, though some activists insist adequate reserves are on hand.

The plant, which can crank out enough electricity for 1.4 million homes, has been shut down for nearly three months while investigators try to determine the cause of excessive wear on hundreds of alloy tubes that carries radioactive water in its massive steam generators.

The loss of the nuclear plant also makes it harder to import power into the San Diego area, where reliable energy transmission has long been a thorny issue.

"If the [San Onofre] units remain down, you obviously have less power supply down there. If you have a transmission line go down, or another generator go down, you are in a very tight situation," said Bruce Kaneshiro, a supervisor at the state Public Utilities Commission.

Capt. Dora Lockwood, a Navy spokeswoman, said the company is working on a target for power reductions, if needed, at the numerous Navy installations in San Diego County, which include Naval Base San Diego, the Naval Air Station North Island in Coronado and Marine Corps Air Station Miramar.

"We will do our best, while preserving our capability to carry out our mission responsibilities, to support their request," Lockwood said.

SDG&E spokeswoman Jennifer Ramp said a deal could be finalized shortly.

"The military is aware of the challenges this summer," Ramp said.

State energy planners have been working on a strategy to find replacement power in the region and reduce demand if hot weather hits while the nuclear plant is sidelined. Those plans include restarting two retired power plants in Huntington Beach, urging conservation, such as using air conditioners sparingly, and seeking temporary power cutbacks, if needed, from the military and public agencies.

On Friday, Southern California Edison, which operates San Onofre, asked state regulators to approve a plan to promote conservation among its commercial customers in Orange County -- they can earn a 10 percent rebate by cutting consumption by 10 percent during the summer, when demand is high.

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No date has been set to restart either reactor, which are located between San Diego and Los Angeles.

It takes power to move power, and the restart of the Huntington Beach plants will allow increased transmission into the region, said Stephanie McCorkle, a spokeswoman for the agency that operates the state's wholesale power system, the California Independent System Operator.

The loss of the nuclear plant can restrict power imports into San Diego area by up to 30 percent. The San Diego utility hopes a new, $1.8 billion transmission line will be completed by summer, which would help fill any shortages.

The twin, natural gas-fired plants in Huntington Beach were retired earlier this year. The gas line feeding the plants was severed and 3-foot holes were cut in the boilers, a requirement after taking them out of service.

Eric Pendergraft, president of AES Southland, which operates the Huntington Beach plants, said Thursday that repairs to the boilers and other equipment would begin shortly. He predicted the plants would be ready to restart in mid-May.

The company has to strike agreements with the state wholesale power system before returning to service.

Some officials in nearby communities have been calling for San Onofre to shut down permanently, and last week the Irvine City Council urged the Nuclear Regulatory Commission to thoroughly review safety conditions at the plant before it is considered for relicensing in 2022. The city requested in a letter that the evacuation zone be expanded to 50 miles, from 10 miles.

The trouble at San Onofre began to unfold in late January, when the Unit 3 reactor was shut down as a precaution after a tube break. Traces of radiation escaped, but officials said there was no danger to workers or neighbors. Unit 2 had been taken offline earlier in January for routine maintenance and refueling, but investigators later found unusual wear on tubing in both units.

The excessive tube wear has raised questions about the integrity and safety of replacement generators the company installed in a multimillion-dollar makeover in 2009 and 2010.

The plant's four steam generators each contain nearly 10,000 tubes that carry hot, pressurized water from the reactors. The tubes are a critical safety barrier -- if one or more break, there is the potential that radioactivity could escape into the atmosphere. Also, serious leaks can drain cooling water from a reactor.

Test results show that two types of wear have occurred at both units -- tubes are rubbing and vibrating against adjacent tubes, as well as against support structures inside the generators.

Federal and company investigators are trying to determine why that is happening.

An environmental group, Friends of the Earth, has claimed SCE misled the NRC about design changes that it said are the likely culprit in excessive tube wear and has urged more detailed study before the reactors are restarted.

S. David Freeman, an adviser to the group, said last month that warnings about blackouts are unnecessary, since power can be managed to avoid any customer outages, even without San Onofre.

"California is not and cannot be one power plant away from rolling blackouts," Freeman, a former general manager at the Los Angeles Department of Water and Power, wrote to the Independent System Operator.

He said it was disturbing that state energy officials are "warning of a return of blackouts unless a very troubled nuclear plant is rushed back into operation."

SCE has said safety remains its priority.

The plant is owned by Edison, SDG&E and the City of Riverside. The Unit 1 reactor operated from 1968 to 1992, when it was shut down and dismantled.

For the most recent Navy headlines, visit the Navy News Channel on Military.com.

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ArmyAirRecon Apr 30, 2012 12:11:48 PM

It's California. What did you expect? They're nuts there. The "Greens" are winning.

How's that endangered minnow doing. Put 35,000 people out of work in the San Joaquin Valley. Ran the farmers out of business. Mexican produce better?

How's Govna Moonbeam working out for you idiots. Biggest car market in the country. Not one assembly plant left. Fremont shut down in 2009. Why do you think that is?

I told you so in 2007. If you like California elect Obama and his merry band of radical socialist it's headed right at you. He will turn the whole country into California. Was I right or was I right?

One more reason to get out of California. They're nuts there.

ArmyAirRecon Apr 30, 2012 12:33:30 PM

The last one out of the state . . . turn out the lights.

ArmyAirRecon Apr 30, 2012 12:39:30 PM

My bad. Quarantine the place so it doesn't contaminate the rest of the country. Too late for Oregon, Washington, Nevada and Arizona. Insanity is contagious. Spread to California by Liberals from NEW YORK CITY!

cpjoe2007 Apr 30, 2012 12:41:23 PM

Why doesn't the Navy hook up a couple of their Nuclear-powered carriers to the base and generate their own power?

martytime1 Apr 30, 2012 12:50:23 PM

Let's put some algae, wind turbines, solar panels, and another $1T dollars into this energy of the future. In the meantime, you'll have to get use to living as the folks in North Korea do.

commbubba6 Apr 30, 2012 1:34:24 PM

California needs to go solar. This would be a good time to invest in solar and cut back on hard line.

SudoughCowboy Apr 30, 2012 1:35:48 PM

If people in the neighborhood want to shut down the power plants..good. Let them be shut off from the grid for a year, before anything else changes. Lets see just how badly they want to remove a power source and return to nature.

12321092 Apr 30, 2012 2:17:18 PM

CA. does not want to drill for there own oil/gas,they want it from other places ,this happens every year same old thing they should wise up because some day the rest of us will not give into them...

crabbyoldC-5flteng Apr 30, 2012 2:44:25 PM

There is no hope left for Ca. I couldn't get out of there fast enough. The libs. that have ruined it have not been contained. They have infected all of the surrounding states. It is much better here in Texas, Except for Austin, but they are funny to watch, and a minority of the political power structure here.

ArmyAirRecon Apr 30, 2012 2:50:51 PM

It's much better here in the Ozarks too!

Festus_1961 Apr 30, 2012 3:24:48 PM

Easy Fix. Get a whole bunch of exercise bicycles, hook up generators to them, hook them to the power lines and pedal like mad. Free green power, exercise and weight loss all in one.

22055988 Apr 30, 2012 3:52:30 PM

Most people I know in CA are not liberals except the young ones that is. Cant figure out why they cannot think for them selves and see what is happening. They need change as much as we (the sane) do.

navyjag907 Apr 30, 2012 3:57:11 PM

Strange state and glad I'm not stationed in San Diego anymore. Michigan's a great place--I have my cabin with the front yard on a lake and back yard on the Huron River. I don't golf, fish, or hunt but it's a paradise for those who do and there's no state income tax on military pay. Great VA hospitals, too.

VAL4HAWK Apr 30, 2012 4:18:20 PM

Georgia Sun.................................

The way this story reads...................

ArmyAirRecon Apr 30, 2012 5:33:30 AM

.....the last guy out will be by candle light because the lights will have flickered out years earlier.

Other states just have to shut transmission into CA off. CA has just been exporting their pollution to other states and other countries. We need to charge all stuf sent into CA with a huge environmental surcharge.

This means that the nasty carbon footprint created in North Carolina for a BMW made there coupled with every state that eats the carbon from the transport of that vehicle into CA places a tax on the auto that CA has to pay.

Run the cost of all going into CA to offset the burden they place on everyone else in this great country of ours. Call it a "parasite tax" if you will. If electricity flows in from the four corners get money from CA to clean up the four corners power plants and build clean nuke there.

Why should CA get a free ride on our backs?

It's easy to be an SFO happy camper if all your crap is sent to other states to wallow in and there is no penalty to pay for such irresponsible behavior!

4499124 Apr 30, 2012 5:22:36 PM

I'm a third generation southern Californian who has lived in San Diego (Pacific Beach) since I left the army in '65 and to say the navy sprawls all over is an understatement. During the peak of the 'Nam war in '68 and '69 navy and marine presence was very common...I recall navy fighters coming in for landing over old US395 to Miramar and the ships down at 32d St were quite a sight. The weather along the coast is mild, and most of us don't need A/C except during some days in Sept.

Bit Apr 30, 2012 6:49:01 PM

Park a nuclear carrier there and hook up the power!

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indianmedicine Apr 30, 2012 7:15:29 PM

There may have been a smile on the suggestion of a NUC Carrier supplementing Navy Electricity; but it is a plausible idea...................... .... The problem, is how to "tie" that Source into the existing "Grid",without "spiking" existing Power in the lines; which is known to be "dirty electricity" because of constant "fluctuation" in the Lines................................... .... "Solar" Energy should be written into "Construction Codes" since that Industry Technology is Cost Effective, and "Sun Shine" is abundant in a nearly constant rate.............. ....(Japan uses Solar Panels on Tall Structures as a matter of SOP in industrial areas)......... ....(Any Engineers Listening?)................. .... It is also plausible that a Desalinization Plant is Cost Effective for Domestic Water for San Diego County/City.......................... .... The Planning Commission for City & County now see why "PPP" is necessary for future Resource Management..................................... .... SD has two "moth balled" Fossil Fuel Power Plants that are part of the "Emergency Power Plans" for the City & County................... .... -De Oppresso Liber-Non Gratum Anus Rodentum-.... ....

8952389 Apr 30, 2012 9:26:26 PM

At first, I thought they were going to say, California was plugging into a Navy Nuke Carrier for power.

ArmyAirRecon Apr 30, 2012 9:33:00 PM

Hollywood is not part of California. Hollywood is part of New York City that lives in California.

San Francisco, Special Interests and the Unions run Sacramento.

The money is in the South and the power is in the bay.

San Francisco is the self proclaimed home of the communist party on the west coast. It has been that way since CIO Union organizers came there from New York. Before CIO and AFofL merged. CIO was communist and AF of L was anti-communist. They got into a war and tried to burn down SF.

The CTA teachers Union and government employee unions are the most power unions in the state, as Arnold found out. You can't beat the Unions.

Every liberal special interest group on the planet has a presence and influence in Sacramento.

Then there is the 9th circus court.

So they have taxed and regulated all the money and high paying jobs out of the state. Gas is sixty cents a gallon higher there than here. It was 7 bucks a gallon on Catalina. One of the highest cost of living in the country. Sanctuary cities import crime and poverty and drive up welfare costs. They underfund the police.

Liberals have taken the best place in the country to live in the fifties and screwed it up completely. Place is not fit for human habitation

All you libs who think California is some kind of Paradise have my blessing to just all move there. You can all go bankrupt together.

Govna Moonbeam! I rest my case!

ArmyAirRecon Apr 30, 2012 10:00:43 PM

I remember when Edmund G. "Pat" Brown was Governor.

I remember when Jerry Brown was Governor the first time. Jerry Brown was Mayor of Oakland, the shite hole on the bay.

You idiots in California elected that hippie screwball again! You deserve what happens next!

G O V N A M O O N B E A M !

AAHHHAAaaaa Ha ha Haaaaa! You Can have it without me. I'm from Chicago. I grew up in L. A. I despise every last square inch of L. A. The best part of California is the view in the rear view mirror for the last time.

:-)

Jamie42 Apr 30, 2012 11:18:15 PM

What I have continually wondered about is WHY our Country does not use the Naval designed Nuclear power plants? As far as I know, and unless it was deeply covered up; our Navy has never had a mishap with one of their systems. Anyone out there who dealt with these plants know for sure? I also remember a historical artical a few years ago in the Tacoma News Tribune newspaper; about the city being powered by a Naval ship during a major power disruption. As another commenter stated, WHY NOT hook up the Navy Yards/bases in the general area and have them powered by a Nuclear powered ship? Seems like it would be a win-win for everyone.

8952389 Apr 30, 2012 11:24:59 PM

Yes, I can see it now, Jane Fonda re-releases "China Syndrome". Push back nuke development for another 10 years. Hey I know, what about some coal fired plants. Guess not. OK, how about some natural gas from off the coast. Oh, thats right, can't do that. Well then, wind powered turbines might do it. No, can't do that, birds will fly into the props. Heck, how about solar? Oh thats right, the lizards won't be able to cross over the desert floor. What the hell, "Surf's Up!"

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nomobobo May 2, 2012 1:21:04 PM

Where do they store the unused power so that it will be available later?

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nomobobo May 2, 2012 1:23:09 PM

Anyone remember G R A Y D A V I S ????

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cdr_r May 3, 2012 4:11:19 AM

Don't worry - the hypocrites will buy power from Arizona al the while chanting "BOYCOTT ARIZONA FOR SB1070"... COme on I double dog dare those liberals to own pu and pull the plug to Arizona. I do hope Arizona ups the price in return for those "kind" liberal antics.

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irmedic85242 May 3, 2012 4:18:58 AM

Well the USS. Enterprise is finishing her last deployment, Turn her into the Museum ship in San Diego and let her reactors help with power for the city. At least this way she won't be chopped up for scrap.

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