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Microturbine Economic Competitiveness: A Study of Two Potential Adopters

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Microturbine Economic Competitiveness: A Study of Two Potential Adopters

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Acronyms and Abbreviations

CARB 2007	DG emissions limits imposed by CARB beginning in 2007
CARB	California Air Resources Board
CHP	combined heat and power
CO	carbon monoxide
DER	distributed energy resources
DER-CAM	Distributed Energy Resources Customer Adoption Model
DG	distributed generation
DLE	dry low emissions
EGR	exhaust gas recirculation
ICE	internal combustion engine, a.k.a. reciprocating engine
kW	kilowatt
LBNL	Ernest Orlando Lawrence Berkeley National Laboratory
MT	microturbine
MW	megawatt
NBVC	Naval Base Ventura County
NOx	nitrogen oxides
SCR	selective catalytic reduction
TOU	time of use
WCCH	Wyoming County Community Hospital

Abstract

MT Economic Competitiveness: A Study of Two Potential Adopters
by Ryan Firestone and Chris Marnay
LBNL-57985
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This project evaluates what $/kW subsidy on microturbines (MT's) makes them economically competitive with natural gas internal combustion engines (ICE's). The Distributed Energy Resources Customer Adoption Model (DER-CAM) is used to determine least cost solutions, including distributed generation (DG) investment and operation, to sites' energy demands.

The first site considered is a hospital in New York City. The small hospital (90 beds) has a peak electric load (including cooling) of 1200 kW, with heat loads comparable to electric loads. Consolidated Edison electricity and natural gas tariffs for 2003 are used. A 60% minimum DG system efficiency is imposed on DG operation to avoid the standby tariff, which is less amenable to DG than the parent tariff.

The second site considered is the Naval Base Ventura County commissary in Southern California. The commissary has 13,000 m^2 of floor space and contains a large retail store, supermarket, food court, and other small businesses. The site peak electric load (including cooling) is 1050 kW. Electricity and natural gas supply are from direct access contracts, and delivery service is provided by Southern California Edison and Southern California Gas, respectively. 2003 supply and delivery rates are used.

For both sites, three cases are considered:
- Base Case: MT's and ICE's are both 98% reliable, MT's have a 10 year lifetime and ICE's a 20 year lifetime
- Reliability Case: MT's reliabilities of 93%, 98%, and 100% are considered. Unreliability affects the demand charge in DER-CAM.
- Extended Lifetime Case: MT lifetimes of 10, 15, and 20 years are considered

In all cases, DG purchase options for generation are
- electricity generation device only
- electricity generation device with heat recovery for heating
- electricity generation device with heat recovery for heating and absorption cooling

A 6 year simple payback period constraint is imposed on all investment considerations.

One advantage of MT's over ICE's is that MT's have lower NOx emissions rates in many cases. For this project, strict emissions regulations, such as the 2007 California Air Resources Board DG requirements, are assumed; therefore, ICEs require selective catalytic reduction (SCR) to reduce NOx emissions to acceptable levels. SCR adds 20% to the capital cost and $0.008/kWh to the variable operation and maintenance costs of ICEs[1]. MT's do not require exhaust after-

[1] Exhaust gas recirculation (ERG) uses exhaust gas instead of excess air to achieve a lean burn. Inexpensive 3-way catalysts can be used as the exhaust after-treatment because of the low oxygen level of the exhaust. To date, this technology has only been

treatment, but, for this project, are constrained to run at 90% or higher of capacity to maintain low NOx rates.

MT purchase options include packages with single and double effect chillers. Double effect chillers are more expensive than single effect chillers, but also more efficient. ICE purchase options only include packages with single effect chillers.

Key findings include:

- For MT's to be economically competitive with ICE's under low NOx emissions regulations, MT turnkey costs must be reduced by $500/kW for the California naval base and $800/kW for the New York City hospital.
- MT's with lower reliability (93%) only increase annual energy costs by about 0.5%-1.5% compared to MT's with higher reliability (98%).
- MT's with a 50% higher lifetime (15 years) than the current 10 year lifetime MT's can reduce annual energy costs by 5%.
- Systems with double-effect chillers do not provide significantly lower cost solutions than single-effect chiller systems.

MT cost reductions can be realized through:

- Economies of scale in production to reduce equipment costs
- Streamlined installation procedures to reduce engineering and installation costs
    - Currently MT installation costs are higher than ICE installation costs because installers have less experience with MT's.

Results in this report are based on tariff data from 2003. Current higher natural gas and electricity prices may lead to different conclusions.

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proven to meet CARB 2007 standards in controlled experiments with fresh catalyst. Several companies are selling EGR/3-way catalyst products, but none are guaranteeing compliance with CARB 2007. ERG could prove to be a lower cost approach to NOx reduction than SCR.

1. Introduction

On-site generation of electricity with combined heat and power (CHP) was once limited to large industrial energy consumers that took advantage of the economies of scale necessary to make self generation with gas turbines (ranging in size from 1 MW to 100's of MW) an economic proposition. However, two prime-movers, internal combustion engines (ICE's) and microturbines (MT's), have made smaller CHP systems (100's of kW) economic for both small commercial and industrial sites. This work explores the economic competitiveness between MT's and ICE's.

In recent years, MT's (~30 to 250 kW) have emerged as a promising alternative to ICE's. MT's have several benefits over ICE's, such as

- fewer moving parts and maintenance requirements, and
- simpler heat recovery (all waste heat is emitted as high temperature exhaust)

and quite often have the additional benefits of

- simpler installation,
- reduced noise and vibrations, and
- lower nitrogen oxides (NOx) and carbon monoxide (CO) emissions.

Because of emissions and vibrations reductions, MT's have found a niche market where reciprocating engines are unacceptable or undesirable. In California, a large market for distributed generation (DG), strict emissions standards that come into effect in 2007 may preclude ICE's entirely.[2,3]

However, MT's are less attractive than ICE's in many ways, including

- lower electrical efficiencies,
- higher capital costs,
- possibly shorter lifetimes,
- reliability remains unproven, and
- less ability to meet inductive loads

Low MT emissions have piqued the interest of environmental advocates, and reduced capital costs would make MT's more competitive with ICE's. Competition between MT's and ICE's can be viewed from several perspectives:

- what is the cost reduction required for MT's to compete with ICE's
- what subsidy is required to capture emissions reductions through MT adoption.
- what are the likely added costs resulting from emissions restrictions such as the 2007 California Air Resource Board (CARB) DG requirements.

The objective of this work is to determine what level of capital cost reduction would be required to make MT's economically competitive with ICE's. Determining this level is not as simple as comparing amortized capital costs of MT's and ICE's. The two technologies have different variable costs because of different electrical efficiencies and maintenance requirements.

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[2] To date no ICE has been certified as meeting the California Air Resources Board 2007 standard while one MT has.
[3] Please see Appendix E for more information on NOx emissions.

Additionally, their outputs have different values because of different ratios of waste heat to electricity output.

The Distributed Energy Resources Customer Adoption Model (DER-CAM), a cost minimizing DG design tool developed at Berkeley Lab, is used to estimate the cost reduction of interest. The analysis involves modeling two hypothetical sites and executing the minimization over a range of equipment investment options and MT subsidy levels to determine the breakeven cost where MT's become competitive with ICE's.

This work is structured as follows:

- Section 2 provides an overview of DER-CAM,
- Section 3 describes the sites modeled for this analysis,
- Section 4 describes the experiment and the results, and
- Section 5 summarizes the findings from this work.

2. Distributed Energy Resources Customer Adoption Model (DER-CAM)

This study uses DER-CAM to examine the economic competitiveness of MT's relative to ICE's for two sites: a naval base in California, and a hospital in New York. Developed at Lawrence Berkeley National Laboratory (LBNL), DER-CAM is software designed to determine the most economic DG investment decision for a given site. The solution includes both the type of generating equipment and the optimal operating schedule that minimizes energy costs. DER-CAM input includes the site's hourly end-use energy demand, electricity and natural gas supply costs, and DG technology adoption options.

DG generation technology options can include any on-site options such as PV, and natural gas-fueled ICE's, MT's, gas turbines, and fuel cells, etc. By matching natural gas-fueled generation to heat exchangers and absorption chillers, heat recovered from natural gas driven generators can be used to offset heating and cooling loads. For this project, only ICE's and MT's were considered.

The most common solution includes natural gas-fueled technologies, which can be purchased in any of the following three ways:

- **generator only**: for electricity only,
- **generator and heat exchanger**: for electricity and heat recovery for either domestic hot water or space heating, or
- **generator, heat exchanger, and absorption chiller**: for electricity and heat recovery to serve domestic hot water, space heating, or cooling loads.

In addition to the optimal DG system and the corresponding hourly operating schedule, DER-CAM output also includes the resulting costs, fuel consumption, and carbon emissions. Figure 1 shows a high-level schematic of DER-CAM, which illustrates the key inputs and outputs of the model. References to detailed descriptions of DER-CAM and a list of input modifications made for this effort are provided in Appendix F.

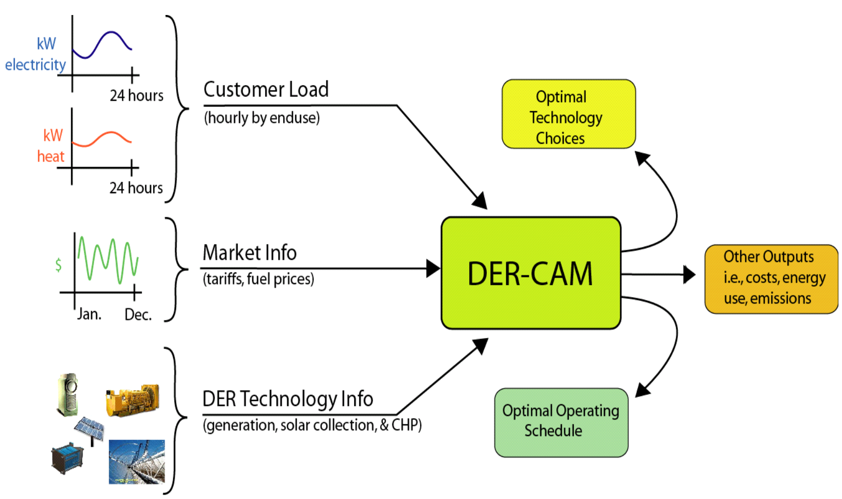

Figure 1: DER-CAM schematic

3. Site selection and data collection

Two prototypical sites were chosen for this study. Typical DG candidate sites were desired, i.e. sites with high utility electricity rates and a significant heat load. The two sites selected were a small hospital in New York City, New York and a naval base commissary in Southern California, which are shown in Figure 2 and Figure 3. For these sites, disaggregated hourly load data was required for DER-CAM, as were electricity and natural gas tariff structures and prices, and DG technology cost and performance data.

The naval base building is a commissary at the Naval Base Ventura County in Port Hueneme, California. Prior experience with this building included site visits and a two-part detailed case study of the commissary (Bailey 2004 and Bailey 2005). The commissary covers 13,000 m^2 of floor-space and contains a large retail store, supermarket, food court, and other small businesses. The annual peak electricity load is 1,050 kW. The commissary has direct access[4] contracts for electricity and natural gas supply[5] together with delivery service from the two local utilities: Southern California Edison and Southern California Gas. Energy prices for 2003 were used, and are reported in Appendix B.

The hospital is modeled after the Wyoming County Community Hospital (WCCH), a small, 90-bed hospital in Warsaw, New York. The WCCH building had also been studied by LBNL as part of an extensive case-studies project (Bailey 2003).[6] In this work, the load profiles were assumed to represent a prototypical hospital in New York City, where higher electricity rates than in Warsaw are more favorable for DG. The hospital has a peak electric load of 1,200 kW with comparable heat loads. Consolidated Edison 2003 rates for electricity and natural gas service in New York City were applied, and are reported in Appendix B.[7]

The end-use disaggregated load profiles for both sites are presented in Appendix A. DG technology costs and performance data are provided in Appendix C.

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[4] From 1996 until 2001, Californians were allowed to contract for electricity supply from an alternative energy service provider, rather than their utility. This purchasing arrangement is known as *direct access*. Under this arrangement the local utility still provides delivery service to the customer and charges the customer accordingly. Customers who signed up for direct access during this period are currently allowed to retain this service arrangement. Similar arrangements are still allowed for natural gas supply.

[5] Government acquired direct access rates may vary from private sector rates; consequently results may vary for private sites.

[6] This site was studied but ultimately was not included as one of the five featured sites examined in Bailey (2003).

[7] In 2004, New York State introduced a new tariff structure for standby customers which is generally less favorable then the original tariff structure. Smaller customers (with a peak load less than 2 MW) can choose to remain on the original tariff if they maintain a 60% minimum CHP system efficiency. Therefore, in modeling the hospital, a 60% minimum efficiency constraint was imposed.

Figure 2: Naval Base Ventura County commissary

Figure 3: Wyoming County Community Hospital

For this project, it was assumed that ICE's require selective catalytic reduction (SCR) to reduce NOx emissions to acceptable regulatory levels, adding 20% to the capital cost and $0.008/kWh to the variable maintenance costs (Firestone 2004). MT's were assumed to not require exhaust after-treatment, but were constrained to run at 90% or higher of capacity to maintain low NOx emissions rates[8].

[8] Although most microturbines would require such a constraint to maintain low NOx levels, the Capstone-60 has been shown to maintain low NOx emissions at operations levels as low as 50% (Southern Research Institute 2003). See Appendix E for estimates of microturbine emissions.

4. Method and Results

A series of DER-CAM runs, herein referred to as a *case*, is used to determine the level of subsidy required to make MT's cost competitive with ICE's. The first set of DER-CAM runs of each case contained no subsidy on MT's, and the option to purchase both ICE's and MT's. For this set, DER-CAM is run once with no investment, once with investment and no payback period constraint, and once with investment and a 6 year payback period constraint.[9] In all cases, the solutions to these runs are purchases of ICE's. Following this initial run, a series of DER-CAM runs is executed with increasing levels of MT subsidy (in the form of reduced capital costs) and purchase options restricted to MT's[10]. Subsidies increase from $0/kW to $1000/kW in increments of $100/kW. For each run, the optimal investment decision and resulting annual energy cost are recorded.

Figures Figure 4 through Figure 9 are at the end of this section and show the annual energy cost (top graph) and installed capacity (bottom graph) under varying MT subsidy level for all cases. The numerical results are reported in Appendix D.

4.1 Base Case

The base case is one in which equipment cost and performance characteristics from Appendix C were used and MT subsidies were varied from zero to $1000/kW. Annual energy cost and DG installed capacity results for the New York City hospital and Southern California naval base commissary are shown in Figure 4 and Figure 5.

4.2 Sensitivities

Aside from cost, reliability and lifetime are two performance parameters for which MT's are considered poorer than ICE's; therefore, the DER-CAM runs are repeated separately for three levels of MT reliability and three levels of MT lifetime.

4.2.1 Reliability

In DER-CAM, it is assumed that there is an equal probability of DG outage at any hour. DER-CAM first assumes perfect reliability to determine energy costs, and then includes a penalty cost that is a function of demand charge, load profile, and equipment reliability, capacity, and quantity. Reliability is directly related to the level of demand charge mitigation that is feasible. The standard MT model in DER-CAM assumes a reliability of 98%. In DER-CAM, the only effect of reliability on cost is to determine the amount of demand charge savings over the no-invest scenario. For the reliability sensitivity, MT reliabilities of 93% and 100% were also considered. Results for these cases are shown in Figure 6 and Figure 7.

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[9] Here, a simple payback period is used, and defined as
[upfront capital cost of system]/[pre-investment annual cost – post-investment annual cost – amortized capital costs]

[10] Excluding ICE's from consideration in these runs was done to avoid solutions containing both MT's and ICE's, which would cloud the results presented here. However, there are situations where DER-CAM would select such mixed solutions, particularly with MT subsidy. In certain situations, solutions would mimic the base-loading (ICE's) and peaker plant (subsidized MT's) solutions used in utility scale power systems.

4.2.2 Lifetime

The standard MT modeled in DER-CAM has a lifetime of 10 years, whereas the lifetime of ICE's is 20 years, and increased lifetime translates into reduced amortized capital costs. As lifetime sensitivities, MT lifetimes of 10, 15, and 20 years were considered, and results for these cases are show in Figure 8 and Figure 9.

4.3 Double-Effect Chillers

One benefit of MT's over ICE's is the high quality heat from MT exhaust. All waste heat from MT's is in the form of exhaust gas at 230ºC to 340ºC.[11] This exhaust can be applied to double-effect absorption chillers,[12] which require higher inlet temperatures than ICE waste heat could provide; however, double-effect chillers are more expensive. The reason for this is that roughly half of the waste heat from ICE's comes from jacket cooling of the engine, which is at a relatively low temperature, while the other half is from exhaust gas at 370ºC-540ºC[13,14]. Preliminary results show little difference in annual energy costs between systems with the two types of chillers; cases with double-effect chillers were therefore not considered for this project.

[11] Goldstein (2003), sec. 4 p. 8.
[12] Single-effect chillers have a coefficient of performance (COP) of 0.6-0.7, whereas double-effect chillers have a COP of 1.1-1.2. For chillers, COP is defined as
[heat removed by system]/[energy provided to system]
[13] Goldstein (2003), sec. 2 p. 14.
[14] It is possible drive a double-effect chiller with the heat from a reciprocating engine: the exhaust can be used to drive the high temperature stage and cooling loop can be used to drive the low temperature stage. This concept is not commercially available and was not considered here.

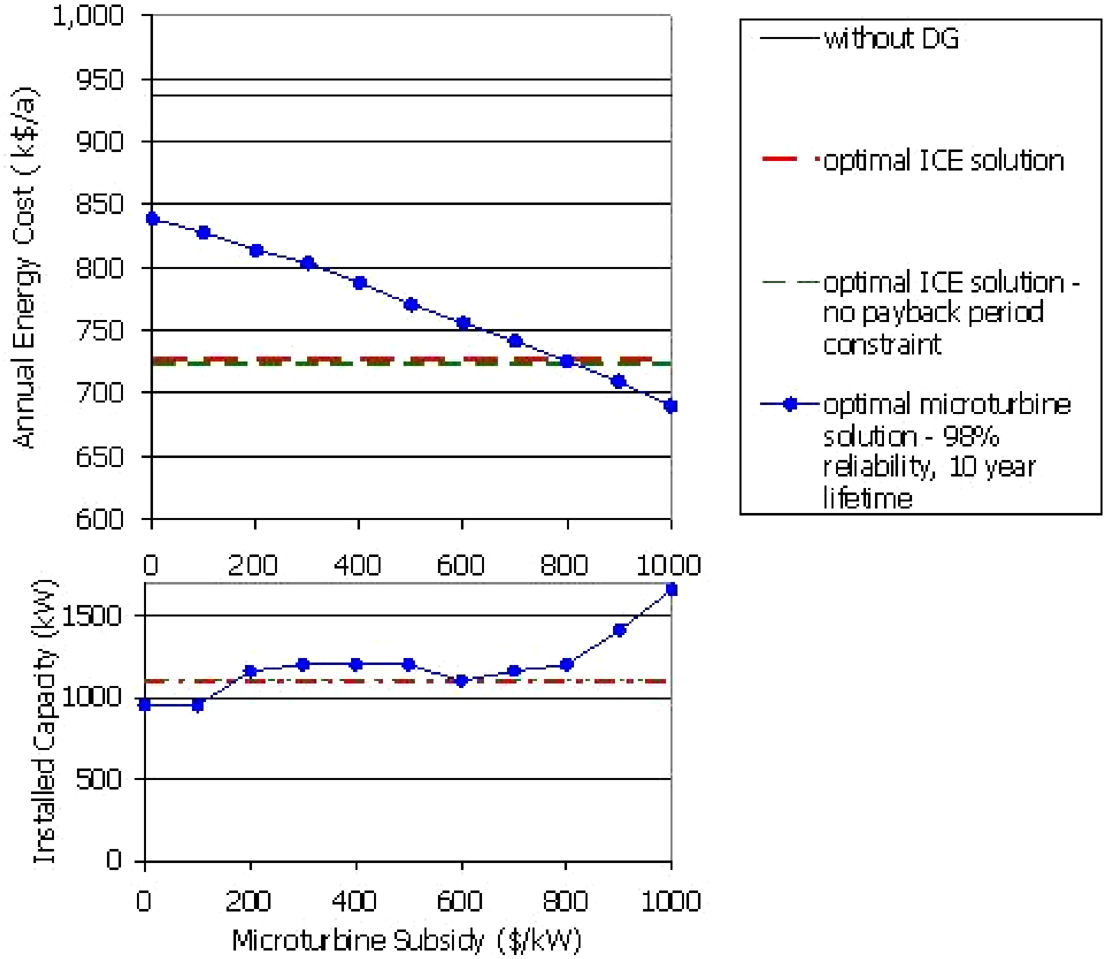

Figure 4: New York City hospital base case results

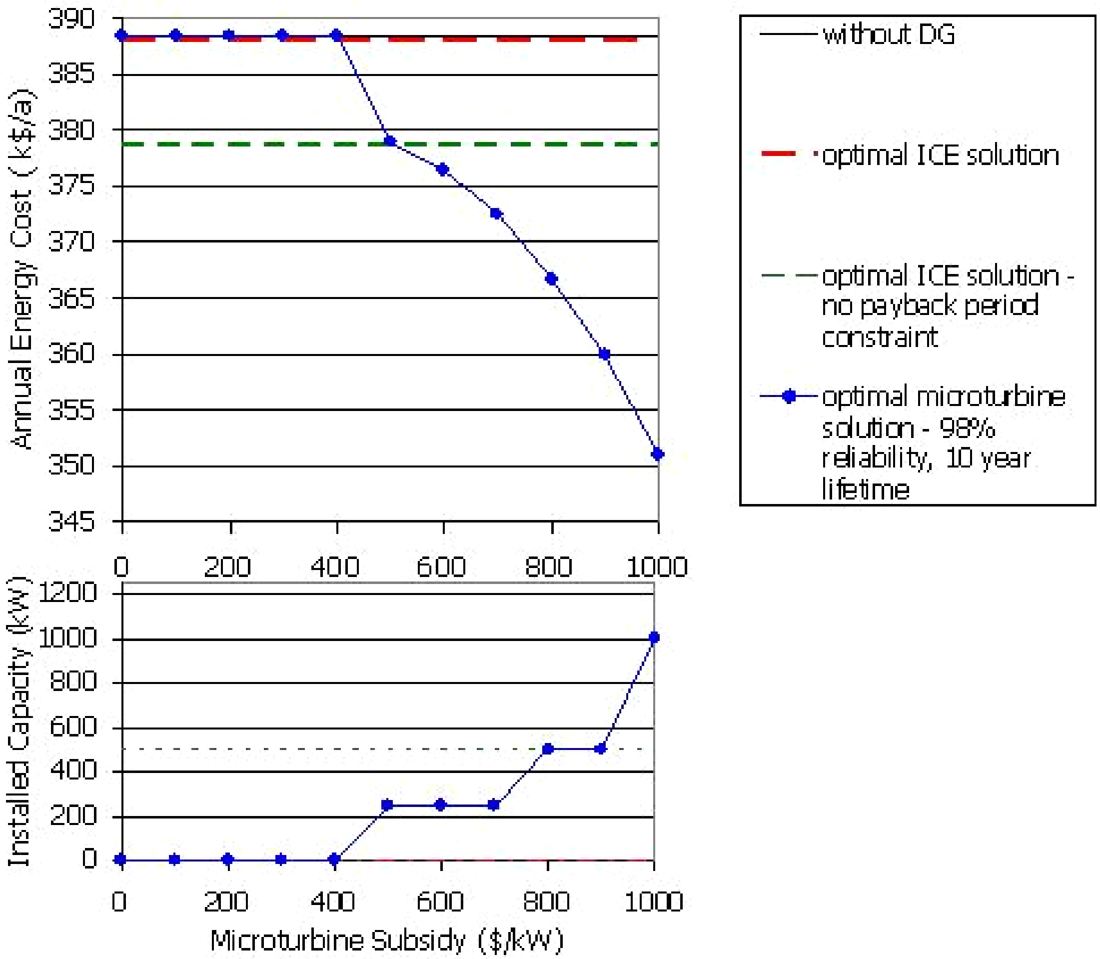

Figure 5: Southern California naval base commissary base case results

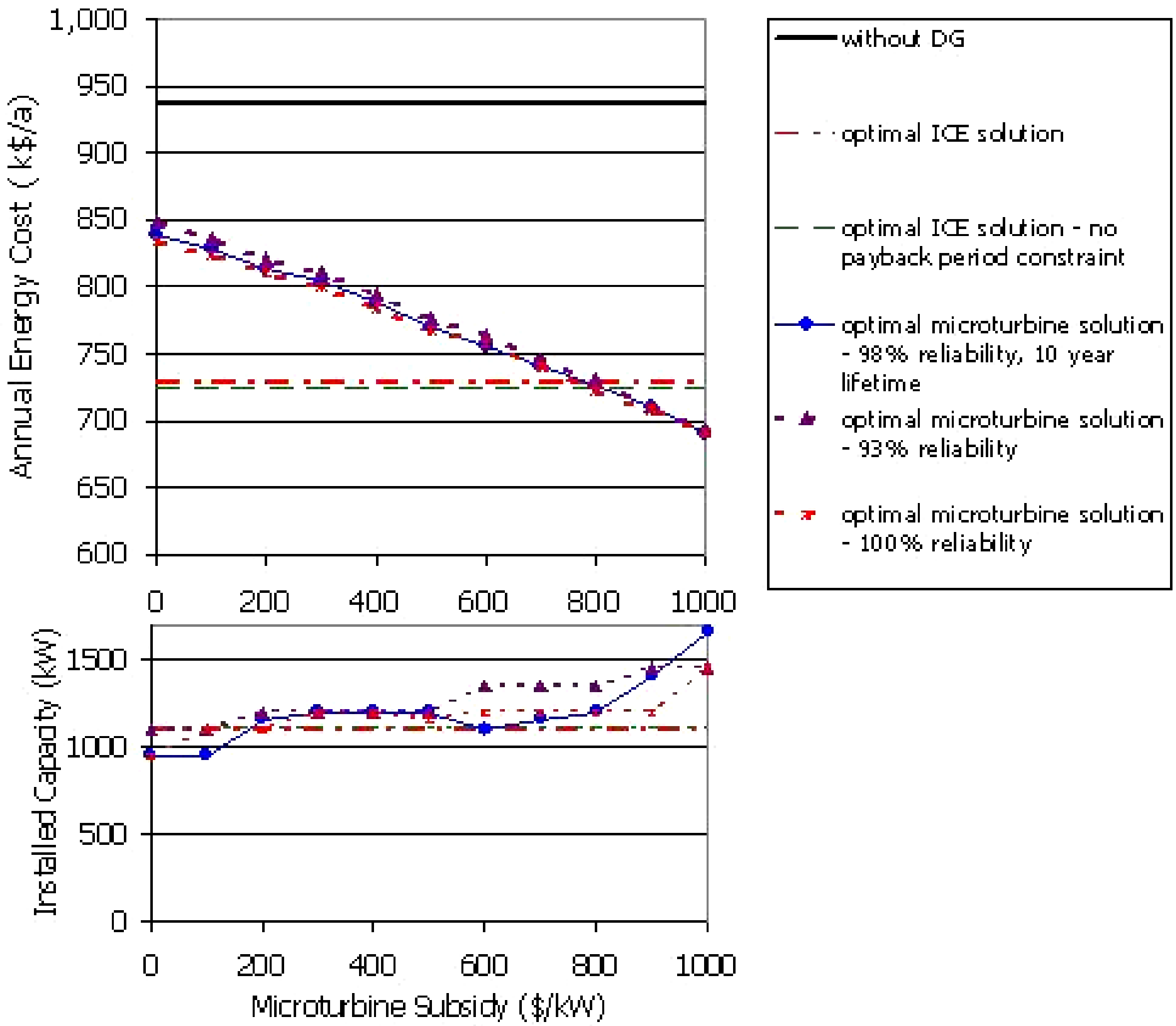

Figure 6: New York hospital reliability sensitivity case results

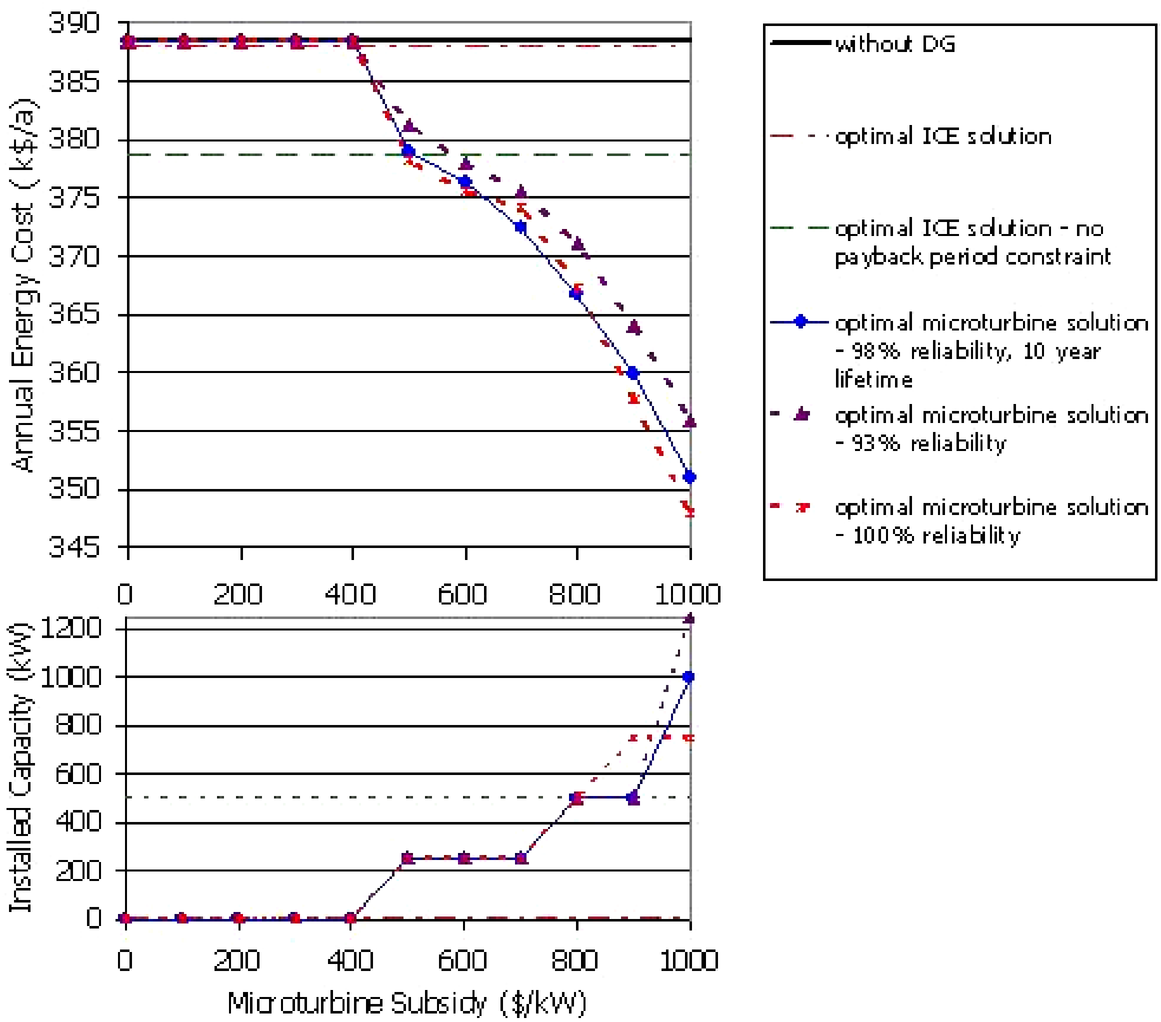

Figure 7: Southern California naval base commissary reliability sensitivity results

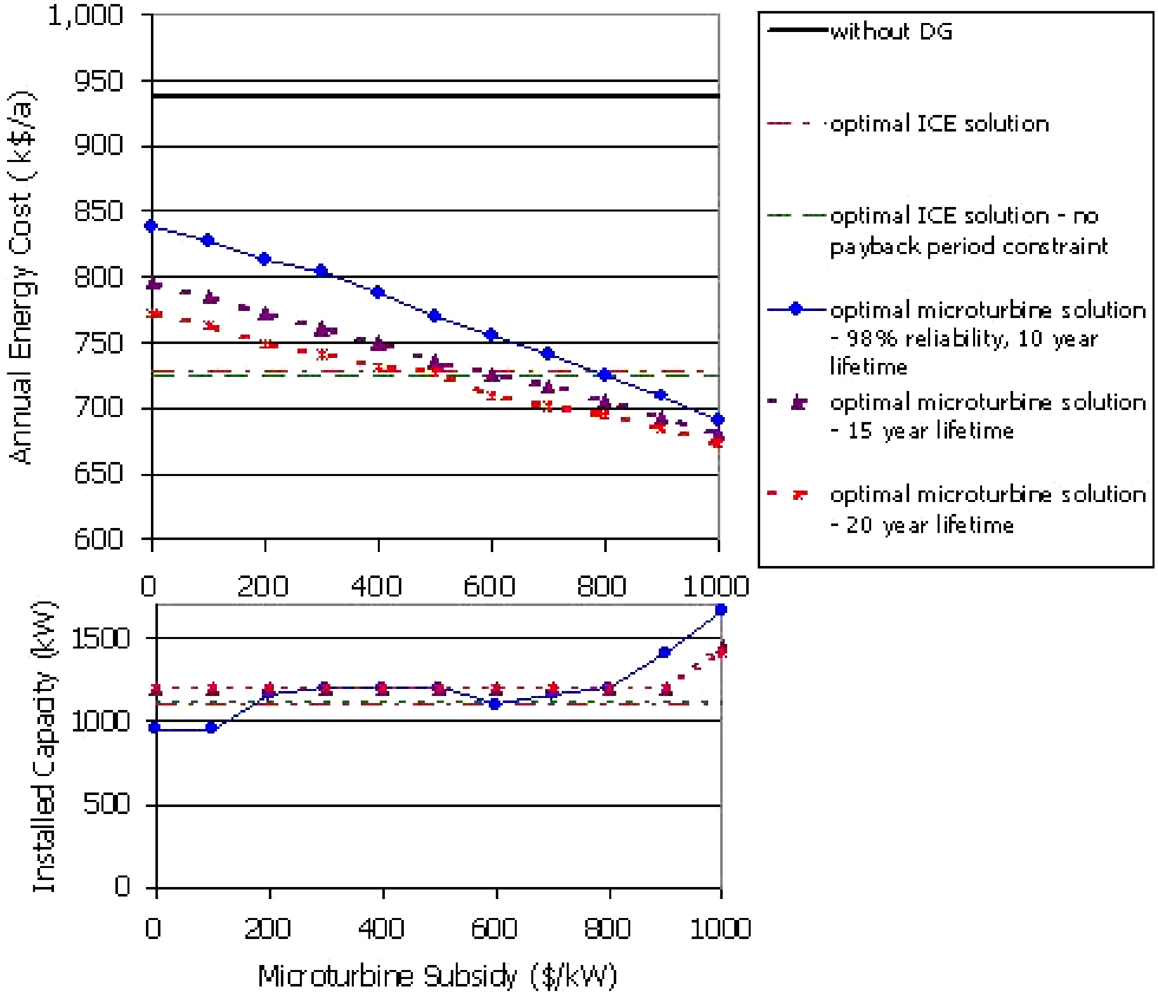

Figure 8: New York hospital lifetime sensitivity case results

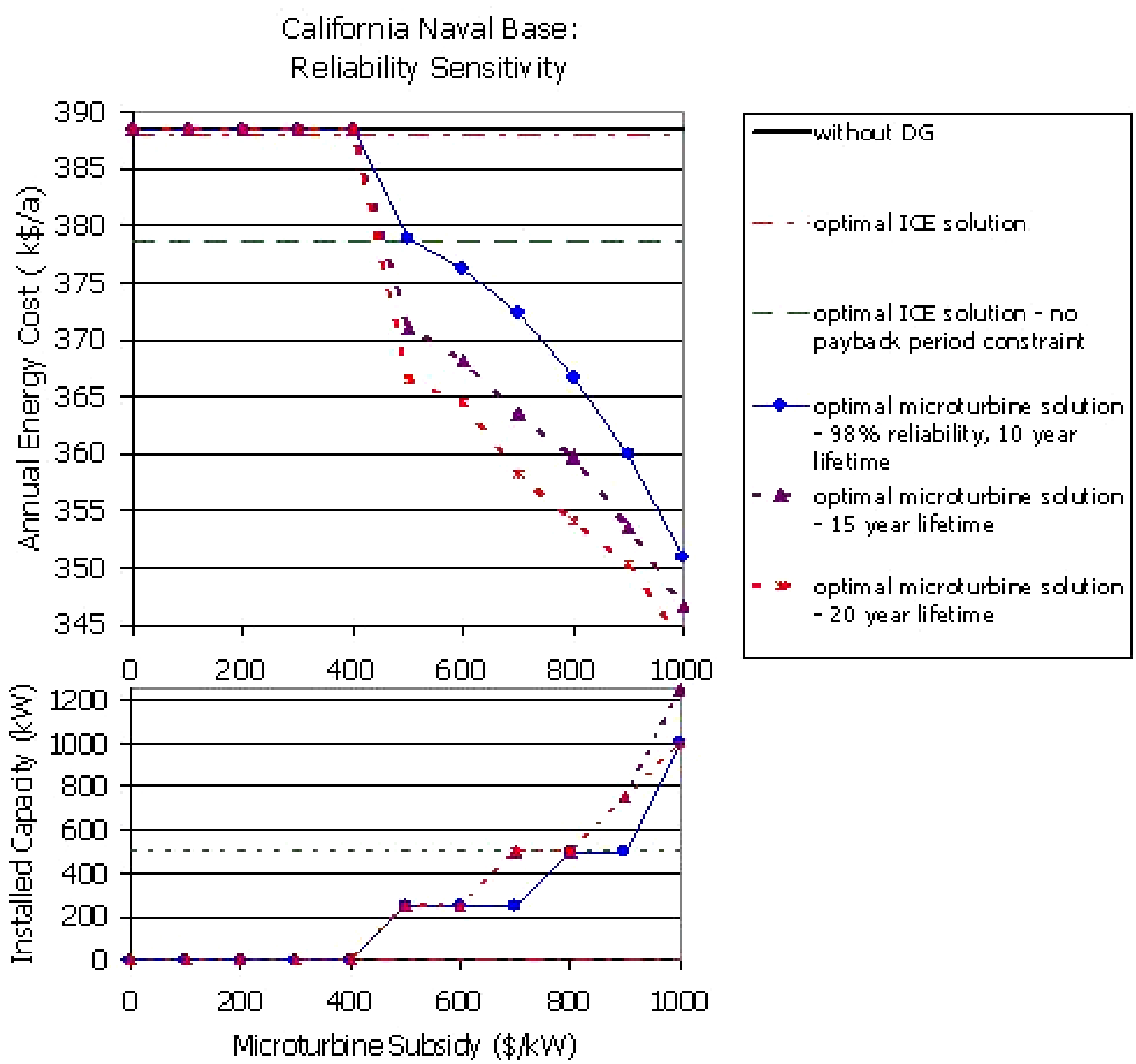

Figure 9: Southern California naval base commissary lifetime sensitivity case results

5. Summary of Findings

This project examined the economic competitiveness of MT's relative to ICE's by determining least cost DG solutions for two sites under varying MT subsidy level. DER-CAM was used to determine least cost solutions. The two sites were a New York hospital and a Southern California naval base commissary. Sensitivity cases with hypothetical MT reliability and lifetime were also studied.

For both sites, ICE's were more economic than unsubsidized MT's. Table 1 summarizes the subsidy level required for economically motivated MT installation for all cases. Note that results are only reported from runs completed with subsidies in 100 $/kW increments, so they do not represent actual break even subsidy levels.

Table 1: MT subsidies ($/kW) required to be economically competitive with ICE's

		New York hospital	Southern California naval base commissary
	base case	800	500
MT reliability sensitivy	93%	800	600
	98%	800	500
	100%	800	500
MT lifetime sensitivity	10 years	800	500
	15 years	600	500
	20 years	500	500

The results in Section 4 illustrate that the less attractive MT electrical efficiency must be compensated by a large capital cost reduction. For MT's to be economically competitive with ICE's under low NOx emissions regulations, MT costs must be reduced by $500/kW for the Southern California naval base and by $800/kW for the New York City hospital. Although MT's offer higher quality waste-heat, systems with double-effect chillers do not provide significantly lower cost solutions than single-effect chiller systems.

MT's with lower reliability (93%) only increase annual energy costs by about 0.5%-1.5% compared to MT's with higher reliability (98%). Perfectly reliable (100%) MT's would lower costs less than 1% (considering demand charge effects only).

This surprising insignificance of reliability is attributable to several factors: MT systems of the capacities installed in these solutions consist of several MT's, for which the probability of a multiple unit outage are small, even at lower reliabilities; the ability to mitigate monthly demand charges is not affected greatly by the level of individual unit reliability. For the New York City hospital, five or more MT's are selected in each case, regardless of reliability value. For all but the summer months, excess capacity is installed. This means that for 8 months out of the year, there is redundant capacity – with multiple generators, this allows for the avoidance of demand charges even when one (or more units in winter months) are unavailable during a critical hour. Additionally, outages are unlikely to occur during the absolute "worst" time during the month, which further decreases the impact of an outage.[15] Demand charges are significantly lower for Southern California naval base commissary than for the New York City hospital[16], while volumetric electricity prices are similar at both sites. This means that demand charges are proportionally much less of the total energy cost in Southern California. Even though the naval base commissary solutions have few numbers of MTs than the hospital solutions, the effect of imperfect reliability on total energy costs is small.

MT's with a 50% higher lifetime (15 years) than the assumed current 10 year lifetime can reduce annual energy costs from 1% to 5%. A 20 year lifetime can reduce costs by up to 8%.

MT's are an emerging technology, which suggests that their capital costs have room for improvement through economies of scale and design improvements. Additionally, MT-based DG system design and installation costs should ultimately be lower than for ICE-based systems because of MT simplicity in setup and connection. While not considered in this study, efficiency is also likely to improve.

[15] To illustrate this, consider a monthly on-peak peak load of 1000 kW, a more typical on-peak load of 900 kW, and five 200 kW MTs installed on-site. For 100% reliable MTs, there would be no utility demand if the MTs were always dispatched. For imperfectly reliable MTs, the expected outage scenario during the month may be that, at most, one MT is unavailable at any hour during the month. It is unlikely that this outage occurs at one of the few peak load hours, and much more likely that it occurs during a more typical load hour. Thus, the expected utility demand would be 100 kW [900 kW load – 800 kW on-site supply], not the 200 kW that might be expected for a 200 kW expected capacity shortfall.

[16] In New York City, total demand changes range from $17/kW in the winter to $34/kw during the summer peak. However, in Southern California under direct access rates, demand charges total $7/kW during the four summer months and $2/kW during the rest of the year.

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Appendix A. End-use Load Profiles

End-use load profiles for the two sites were obtained through data collection at the sites and site modeling in the building energy simulation model, DOE-2. Energy consumption is divided into five categories:

- ***Electricity-only***: end-use loads that can only be met by electricity, e.g. lighting, computing, reported in kWh of electricity required for each hour.
- ***Cooling***: site cooling loads, reported in kWh of electricity that would be required (assuming a COP of 4.5) to provide the desired level of cooling for each hour.
- ***Space-heating***: space heating load of the site, reported in kWh of thermal energy required to meet the load for each hour. In this application of DER-CAM, a central furnace efficiency of 80% was assumed.
- ***Water-heating***: water heating load of the site, reported in kWh of thermal energy required to meet the load for each hour. In this application of DER-CAM, a central boiler efficiency of 80% was assumed.
- ***Natural-gas-only***: loads that can only be met by natural gas, e.g. cooking and decentralized heating, reported in kWh (higher heating value) of natural gas required to meet the load for each hour.

DER-CAM models three days per month: one representing the three peak days of consumption, on representing the remaining weekdays, and one representing the weekend days. Figure App- 1 through Figure App- 5 show the disaggregated load profiles for four representative months for the Wyoming County Community Hospital (WCCH) in Warsaw, New York. These loads are used in this project to represent a prototypical small hospital in New York City. Figure App- 6 through Figure App- 10 show these profiles for the Naval Base Ventura County (NBVC) commissary in Port Hueneme, California.

New York City Hospital

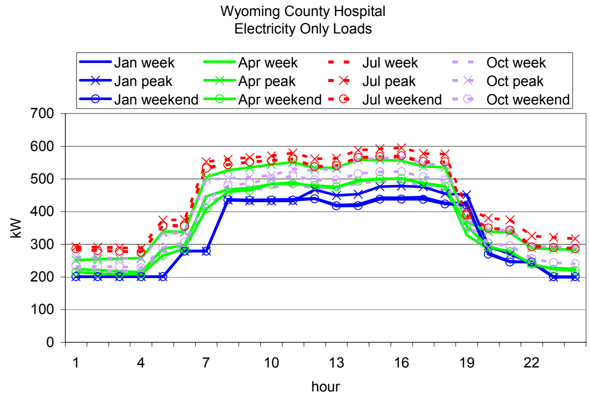

Figure App- 1. WCCH electricity-only loads

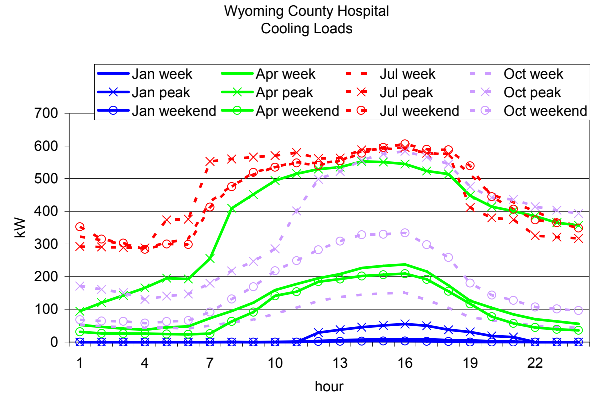

Figure App- 2. WCCH cooling loads

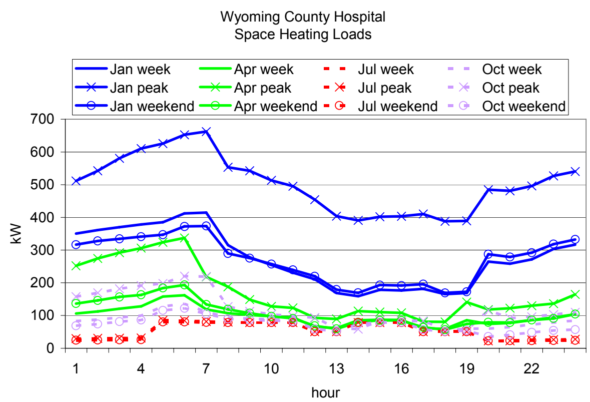

Figure App- 3. WCCH space-heating loads

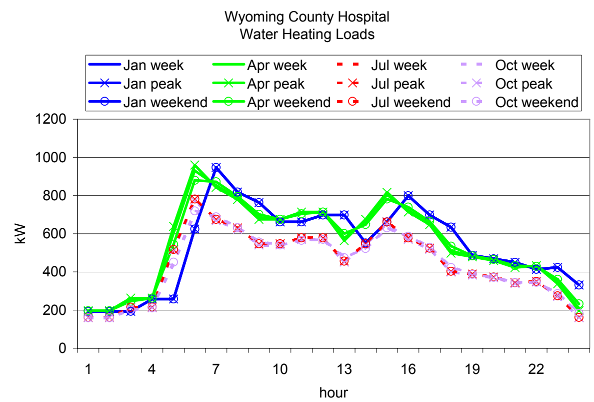

Figure App- 4. WCCH water-heating loads

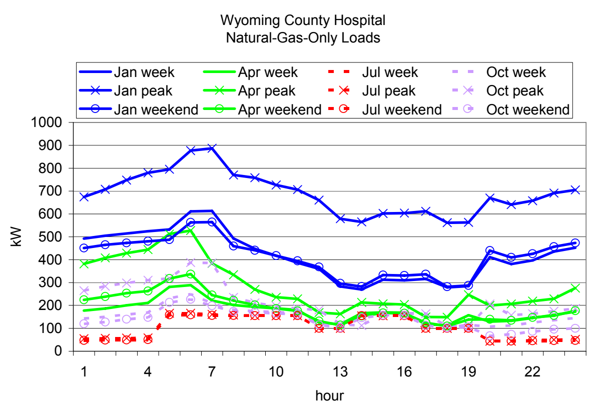

Figure App- 5. WCCH natural-gas-only loads

Southern California Naval Base Commissary

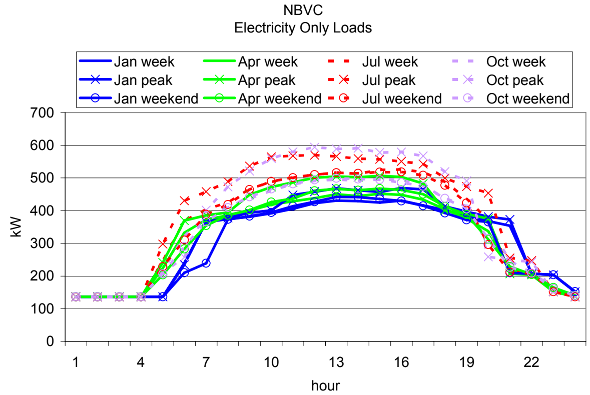

Figure App- 6. NBVC electricity-only loads

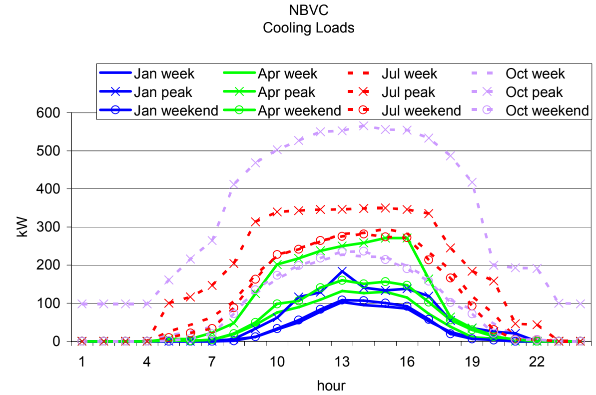

Figure App- 7. NBVC cooling loads

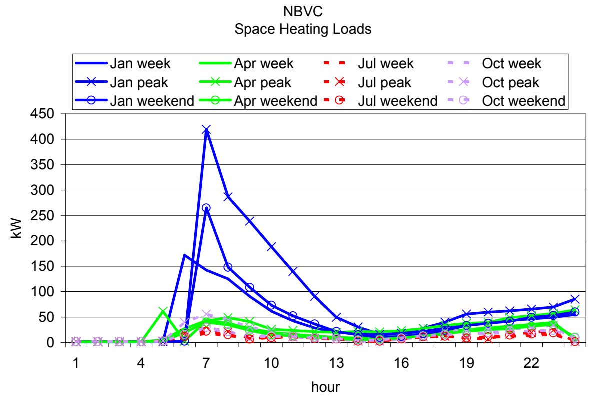

Figure App- 8. NBVC space-heating loads

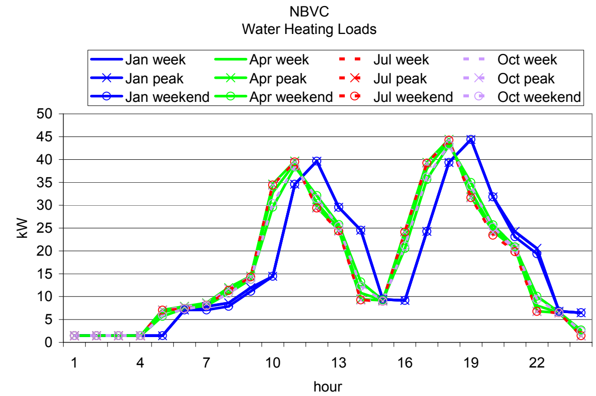

Figure App- 9. NBVC water-heating loads

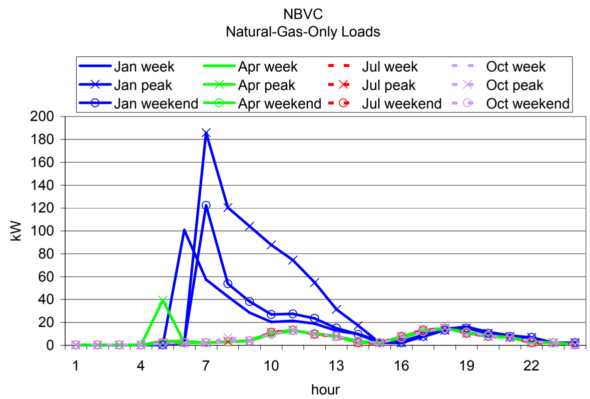

Figure App- 10. NBVC natural-gas-only loads

Appendix B. Energy Costs

Electricity tariffs typically consist of energy ($/kWh) and demand ($/kW) charges. Energy charges are volumetric, i.e. proportional to the amount of electricity consumed, and vary by time of use (TOU). Demand charges are proportional to the maximum rate of electricity consumed, regardless of duration or frequency. Demand charges may have (TOU) and all-hours (non-TOU) components. Table App- 1 shows the Consolidated Edison electricity rates for New York City in 2003. Table App- 2 shows the direct access electricity rates that the NBVC is subject to in Southern California, combined with the delivery rates from Southern California Edison.

Table App- 1. Consolidated Edison TOU-8 electricity rates for New York City in 2003

	Demand ($/kW)				Energy ($/kWh)		
	on-peak	*mid-peak*	*off-peak*	*non-TOU*	*on-peak*	*mid-peak*	*off-peak*
January	14.02	0	0	3.17	0.080	0.049	0.049
February	14.07	0	0	3.17	0.079	0.048	0.048
March	14.61	0	0	3.17	0.071	0.050	0.050
April	14.33	0	0	3.17	0.075	0.054	0.054
May	15.68	0	0	3.17	0.088	0.063	0.063
June	24.07	0	0	9.79	0.101	0.066	0.066
July	22.77	0	0	9.79	0.118	0.071	0.071
August	22.8	0	0	9.79	0.117	0.069	0.069
September	24	0	0	9.79	0.091	0.061	0.061
October	15.69	0	0	3.17	0.084	0.060	0.060
November	14.62	0	0	3.17	0.085	0.065	0.065
December	14.75	0	0	3.17	0.089	0.066	0.066

Table App- 2. Direct access electricity supply and Southern California Edison electricity delivery rates in 2003

	Demand ($/kW)				Energy ($/kWh)		
	on-peak	*mid-peak*	*off-peak*	*non-TOU*	*on-peak*	*mid-peak*	*off-peak*
January	0	0	0	1.61	0.098	0.098	0.098
February	0	0	0	1.61	0.098	0.098	0.098
March	0	0	0	1.61	0.098	0.098	0.098
April	0	0	0	1.61	0.098	0.098	0.098
May	0	0	0	1.61	0.098	0.098	0.098
June	5.3	0.46	0	1.61	0.098	0.098	0.098
July	5.3	0.46	0	1.61	0.098	0.098	0.098
August	5.3	0.46	0	1.61	0.098	0.098	0.098
September	5.3	0.46	0	1.61	0.098	0.098	0.098
October	0	0	0	1.61	0.098	0.098	0.098
November	0	0	0	1.61	0.098	0.098	0.098
December	0	0	0	1.61	0.098	0.098	0.098

Natural gas rates consist of monthly charges and volumetric charges. In New York, reduced natural gas rates are available for DG customers for their DG related natural gas consumption because of the higher load factor. Table App- 3 shows the Consolidated Edison natural gas rates for New York City. Table App- 4 shows the direct access electricity rates that the NBVC is subject to in Southern California, combined with the delivery rates from Southern California Gas.

Table App- 3. Consolidated Edison natural gas rates for New York City in 2003

	Monthly Service Fee		Volumetric Fee					
			$/kJ		*$/kWh*		*$/therm*	
	Basic Service	For DG	Basic Service	For DG	Basic Service	For DG	Basic Service	For DG
January	361.23	141.58	7.23E-06	6.56E-06	0.0260	0.0236	0.76	0.69
February	361.23	141.58	7.64E-06	6.98E-06	0.0275	0.0251	0.81	0.74
March	361.23	141.58	8.60E-06	7.93E-06	0.0310	0.0286	0.91	0.84
April	361.23	141.58	8.57E-06	7.61E-06	0.0309	0.0274	0.90	0.80
May	361.23	141.58	8.38E-06	7.42E-06	0.0302	0.0267	0.88	0.78
June	361.23	141.58	9.13E-06	8.17E-06	0.0329	0.0294	0.96	0.86
July	361.23	141.58	8.95E-06	7.98E-06	0.0322	0.0287	0.94	0.84
August	361.23	141.58	8.60E-06	7.63E-06	0.0309	0.0275	0.91	0.81
September	361.23	141.58	8.79E-06	7.83E-06	0.0316	0.0282	0.93	0.83
October	361.23	141.58	8.03E-06	7.07E-06	0.0289	0.0254	0.85	0.75
November	361.23	141.58	8.35E-06	7.68E-06	0.0301	0.0277	0.88	0.81
December	361.23	141.58	8.42E-06	7.75E-06	0.0303	0.0279	0.89	0.82

Table App- 4. Direct access supply and Southern California Gas delivery natural gas rates for 2003

	Monthly Service Fee		Volumetric Fee					
			$/kJ		$/kWh		$/therm	
	Basic Service	For DG	Basic Service	For DG	Basic Service	For DG	Basic Service	For DG
January	350.00	0.00	6.06E-06	6.06E-06	0.0218	0.0218	0.64	0.64
February	350.00	0.00	6.06E-06	6.06E-06	0.0218	0.0218	0.64	0.64
March	350.00	0.00	6.06E-06	6.06E-06	0.0218	0.0218	0.64	0.64
April	350.00	0.00	6.06E-06	6.06E-06	0.0218	0.0218	0.64	0.64
May	350.00	0.00	6.06E-06	6.06E-06	0.0218	0.0218	0.64	0.64
June	350.00	0.00	6.06E-06	6.06E-06	0.0218	0.0218	0.64	0.64
July	350.00	0.00	6.06E-06	6.06E-06	0.0218	0.0218	0.64	0.64
August	350.00	0.00	6.06E-06	6.06E-06	0.0218	0.0218	0.64	0.64
September	350.00	0.00	6.06E-06	6.06E-06	0.0218	0.0218	0.64	0.64
October	350.00	0.00	6.06E-06	6.06E-06	0.0218	0.0218	0.64	0.64
November	350.00	0.00	6.06E-06	6.06E-06	0.0218	0.0218	0.64	0.64
December	350.00	0.00	6.06E-06	6.06E-06	0.0218	0.0218	0.64	0.64

Appendix C. Equipment Cost and Performance Data

The data in Table App- 5 was used as equipment cost and performance data for DER-CAM. This data is derived from Firestone (2004) and Goldstein (2003), and includes a 20% mark-up to capital costs and a $0.008/kWh increase to maintenance costs for ICE's to account for SCR.

Table App- 5. Equipment cost and performance data

		Turnkey Capital Costs ($/kW)						
			CHP					
		electricity only	*heating*	*heating and cooling*	*operation and maintenance costs ($/kWh)*	*electricial efficiency (HHV)*	*heat to electricity ratio*	*lifetime (years)*
Internal Combustion Engines (with SCR)	***60 kW***	1190	1560	2146	0.026	28.7%	2.2	20
	100 kW	1143	1494	1998	0.025	29.6%	2	20
	250 kW	1028	1330	1747	0.023	31.2%	1.8	20
	500 kW	996	1283	1571	0.021	32.4%	1.7	20
Microturbines	***60 kW***	1828	2125	2494	0.011	24.5%	2	10
	100 kW	1547	1828	2134	0.011	25.7%	1.8	10
	250 kW	1043	1295	1504	0.011	28.0%	1.4	10

Appendix D. Results: Optimal Investment Decisions For All Scenarios

This appendix contains the optimal purchase decision for all DER-CAM runs constrained to MT purchase only, and the resulting annual energy costs. Table App- 6 through Table App- 8 show results for the New York City hospital. Table App- 9 through Table App- 11 show results for the Southern California naval base commissary.

New York City Hospital

Table App- 6. New York City hospital base case results

	Microturbine Subsidy ($/kW)	***0***	***100***	***200***	***300***	***400***	***500***	***600***	***700***	***800***	***900***	***1000***
	Annual Energy Cost	$838,608	$827,764	$813,677	$803,542	$788,016	$770,507	$755,951	$741,710	$725,620	$709,398	$690,024
	Installed Microturbine Electrical Capacity (kW)	950	950	1160	1200	1200	1200	1100	1160	1200	1410	1660
	DER Packages Purchased											
Electricity-only	60 kW											
	100 kW											
	250 kW	1	1	2	2	2	2	2	2	2	2	3
Heat recovery for heating	60 kW			1							1	1
	100 kW	2	2	1	2	2	2	1	1	1	1	1
	250 kW	1	1	2	1	1	2	2	1	2	2	2
Heat recovery for heating and cooling	60 kW								1			
	100 kW									1		
	250 kW	1	1		1	1			1		1	1

solution without subsidies (both with and without payback period constraint) is to purchase one 500 kW ICE with heat recovery for heating and cooling, one 250 kW ICE with heat recovery for heating, one 250 kW ICE without heat recovery and one 100 kW ICE without heat recovery

Table App- 7. New York City hospital reliability sensitivity case results

93% Reliability Scenario

	Microturbine Subsidy ($/kW)	***0***	***100***	***200***	***300***	***400***	***500***	***600***	***700***	***800***	***900***	***1000***
	Annual Energy Cost	$848,397	$835,781	$820,681	$810,538	$793,882	$775,572	$763,608	$745,732	$729,964	$711,299	$692,172
	Installed Microturbine Electrical Capacity (kW)	1100	1100	1200	1200	1200	1200	1350	1350	1350	1450	1450
	DER Packages Purchased											
Electricity-only	60 kW											
	100 kW											
	250 kW	2	2	2	2	2	2	3	3	2	3	3
Heat recovery for heating	60 kW											
	100 kW	1	1	2	2	2	2	1	1	1	2	2
	250 kW	2	1	1	2	1	2	2	2	2	2	2
Heat recovery for heating and cooling	60 kW											
	100 kW											
	250 kW		1	1		1				1		

100% Reliability Scenario

	Microturbine Subsidy ($/kW)	***0***	***100***	***200***	***300***	***400***	***500***	***600***	***700***	***800***	***900***	***1000***
	Annual Energy Cost	$833,614	$823,552	$809,805	$800,183	$784,257	$767,498	$757,785	$740,577	$721,889	$708,254	$691,020
	Installed Microturbine Electrical Capacity (kW)	950	1100	1100	1200	1200	1160	1200	1200	1200	1200	1450
	DER Packages Purchased											
Electricity-only	60 kW											
	100 kW											
	250 kW	1	2	2	2	2	2	2	2	2	2	3
Heat recovery for heating	60 kW											
	100 kW	2	1	1	2	2	1	2	2	2	2	2
	250 kW	1	1	1	1	1	2	1	2	2	2	2
Heat recovery for heating and cooling	60 kW						1					
	100 kW											
	250 kW	1	1	1	1	1		1				

Table App- 8. New York City hospital lifetime sensitivity case results

15 Year Lifetime Scenario

	Microturbine Subsidy ($/kW)	*0*	*100*	*200*	*300*	*400*	*500*	*600*	*700*	*800*	*900*	*1000*
	Annual Energy Cost	$795,412	$784,528	$772,157	$760,936	$750,123	$735,696	$725,946	$717,490	$706,285	$693,296	$680,276
	Installed Microturbine Electrical Capacity (kW)	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1450
	DER Packages Purchased											
Electricity-only	60 kW											
	100 kW											
	250 kW	2	2	2	2	2	2	2	2	2	2	3
Heat recovery for heating	60 kW											
	100 kW	2	2	2	2	2	2	2	2	2	2	2
	250 kW	1	1	1	1	1	1	1	1	2	2	2
Heat recovery for heating and cooling	60 kW											
	100 kW											
	250 kW	1	1	1	1	1	1	1	1			

20 Year Lifetime Scenario

	Microturbine Subsidy ($/kW)	*0*	*100*	*200*	*300*	*400*	*500*	*600*	*700*	*800*	*900*	*1000*
	Annual Energy Cost	$772,441	$762,696	$748,904	$741,069	$731,846	$727,202	$709,489	$701,444	$694,709	$684,950	$673,160
	Installed Microturbine Electrical Capacity (kW)	1200	1200	1160	1200	1200	1200	1200	1200	1200	1200	1410
	DER Packages Purchased											
Electricity-only	60 kW											
	100 kW											
	250 kW	2	2	2	1	2	1	1	2	2	2	2
Heat recovery for heating	60 kW											1
	100 kW	2	2	1	2	2	2	2	2	2	2	1
	250 kW	1	1	1	2	1	1	1	1	1	1	2
Heat recovery for heating and cooling	60 kW			1								
	100 kW											
	250 kW	1	1	1	1	1	2	2	1	1	1	1

Southern California Naval Base Commissary

Table App- 9. Southern California naval base commissary base case results

	Microturbine Subsidy ($/kW)	*0*	*100*	*200*	*300*	*400*	*500*	*600*	*700*	*800*	*900*	*1000*
	Annual Energy Cost	$388,442	$388,442	$388,442	$388,442	$388,442	$378,909	$376,302	$372,434	$366,647	$359,882	$350,903
	Installed Microturbine Electrical Capacity (kW)	0	0	0	0	0	250	250	250	500	500	1000
	DER Packages Purchased											
Electricity-only	60 kW											
	100 kW											
	250 kW									1	1	3
Heat recovery for heating	60 kW											
	100 kW											
	250 kW											
Heat recovery for heating and cooling	60 kW											
	100 kW											
	250 kW						1	1	1	1	1	1

solution without subsidies is no DG adoption
solution with subsidies and without payback period constraint is to purchase one 500 kW ICE with heat recovery for heating and cooling

Table App- 10. Southern California naval base commissary reliability sensitivity case results

93% Reliability Scenario

		0	100	200	300	400	500	600	700	800	900	1000
	Microturbine Subsidy ($/kW)	***0***	***100***	***200***	***300***	***400***	***500***	***600***	***700***	***800***	***900***	***1000***
	Annual Energy Cost	$388,442	$388,442	$388,442	$388,442	$388,442	$381,193	$377,955	$375,574	$371,115	$363,988	$355,952
	Installed Microturbine Electrical Capacity (kW)	0	0	0	0	0	250	250	250	500	500	1250
	DER Packages Purchased											
Electricity-only	60 kW											
	100 kW											
	250 kW									1	1	4
Heat recovery for heating	60 kW											
	100 kW											
	250 kW											
Heat recovery for heating and cooling	60 kW											
	100 kW											
	250 kW						1	1	1	1	1	1

100% Reliability Scenario

		0	100	200	300	400	500	600	700	800	900	1000
	Microturbine Subsidy ($/kW)	***0***	***100***	***200***	***300***	***400***	***500***	***600***	***700***	***800***	***900***	***1000***
	Annual Energy Cost	$388,442	$388,442	$388,442	$388,442	$388,442	$378,219	$375,591	$374,149	$367,335	$357,705	$347,935
	Installed Microturbine Electrical Capacity (kW)	0	0	0	0	0	250	250	250	500	750	750
	DER Package											
Electricity-only	60 kW											
	100 kW											
	250 kW									1	2	2
Heat recovery for heating	60 kW											
	100 kW											
	250 kW											
Heat recovery for heating and cooling	60 kW											
	100 kW											
	250 kW						1	1	1	1	1	1

Table App- 11. Southern California naval base commissary lifetime sensitivity case results

15 Year Lifetime Scenario

Microturbine Subsidy ($/kW)	***0***	***100***	***200***	***300***	***400***	***500***	***600***	***700***	***800***	***900***	***1000***
Annual Energy Cost	$388,442	$388,442	$388,442	$388,442	$388,442	$371,101	$368,177	$363,469	$359,754	$353,498	$346,583
Installed Microturbine Electrical Capacity (kW)	0	0	0	0	0	250	250	500	500	750	1250
DER Package											
60 kW											
100 kW											
250 kW								1		2	4
60 kW											
100 kW											
250 kW											
60 kW											
100 kW											
250 kW						1	1	1	2	1	1

20 Year Lifetime Scenario

Microturbine Subsidy ($/kW)	***0***	***100***	***200***	***300***	***400***	***500***	***600***	***700***	***800***	***900***	***1000***
Annual Energy Cost	$388,442	$388,442	$388,442	$388,442	$388,442	$366,544	$364,538	$358,227	$354,116	$350,324	$343,502
Installed Microturbine Electrical Capacity (kW)	0	0	0	0	0	250	250	500	500	750	1000
DER Package											
60 kW											
100 kW											
250 kW										1	2
60 kW											
100 kW											
250 kW											
60 kW											
100 kW											
250 kW						1	1	2	2	2	2

Appendix E. NOx emissions

A key area of superiority for MT's over ICE's is their lower NOx emissions, a parameter of significant environmental concern. The California Air Resources Board (CARB) has set limits on DG NOx emissions for 2007 (0.07 lb/MWh) that will be difficult for ICE's to achieve. Figure App- 11 shows NOx emissions for a range of ICE's with exhaust after-treatment, with and without credit for CHP. "Rich" and "Lean" refer to the amount of fuel allowed during the combustion. Exhaust gas recirculation (ERG) uses exhaust gas instead of excess air to achieve a lean burn. Inexpensive 3-way catalysts can be used as the exhaust after-treatment because of the low oxygen level of the exhaust. To date, this technology has only been proven to meet CARB 2007 standards in controlled experiments with fresh catalyst. Several companies are selling EGR/3-way catalyst products, but none are guaranteeing compliance with CARB 2007.

Figure App- 12 shows the NOx emissions rates for MT's and larger turbines. MT's with the CHP credit should come close to meeting CARB 2007[17]. In order to achieve these low emissions rates, however, MT's must use lean pre-mix combustors referred to as dry low emission (DLE) combustors. At full load, DLE promises ultra-low levels of NOx emissions, but not at part loads. More robust emissions control options would be prohibitively expensive. This is the rationale behind the constraint on MT's to run at 90% to 100% of rated power.

Table App- 12 shows regulatory constraints on NOx emissions in California and New York.

[17] As of November, 2005, an Ingersoll-Rand MT is the only combustion DG technology to be CARB 2007 certified (CARB, 2005 and Pollution Online, 2005).

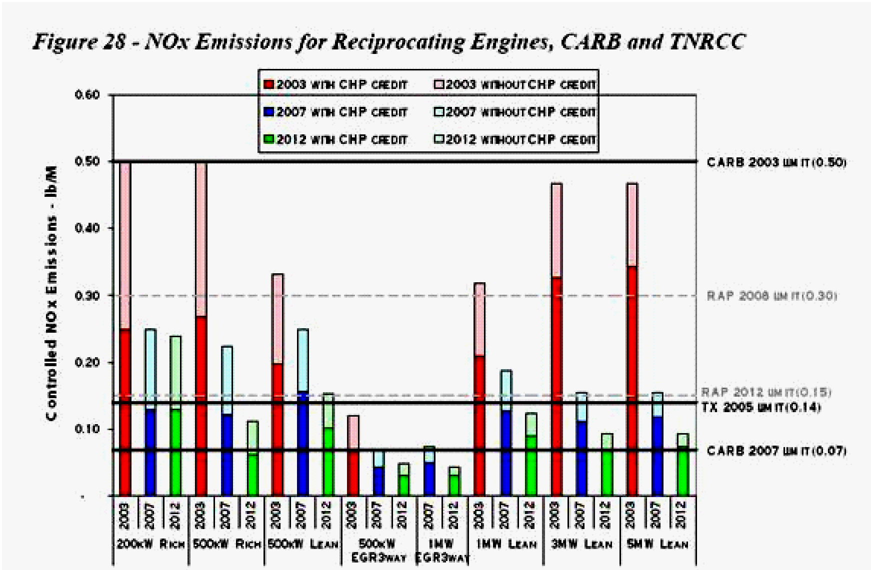

Figure App- 11. Reciprocating engine NOx emissions[18]

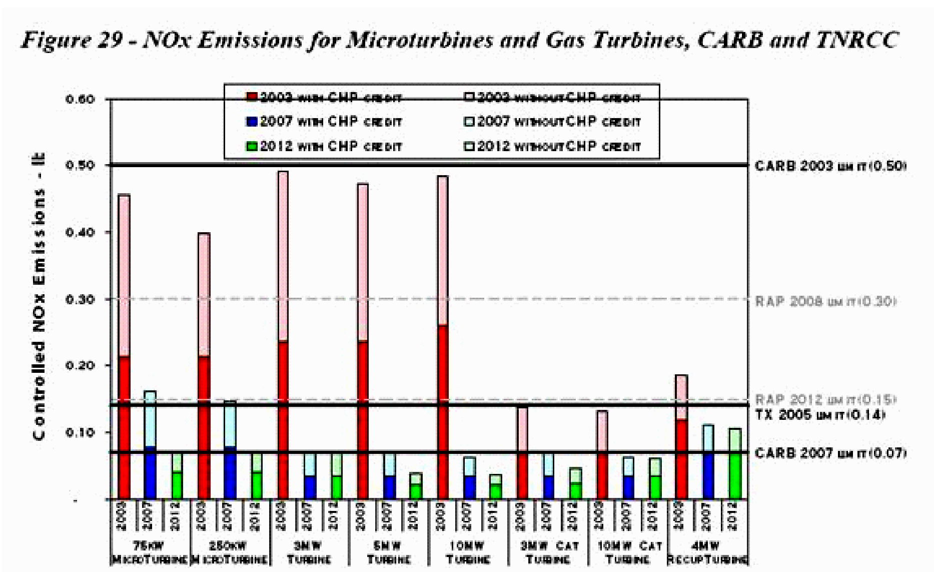

Figure App- 12. MT and turbine NOx emissions[19]

[18] Source: DE Solutions, Inc. (2004), p. 28
[19] Source: DE Solutions, Inc. (2004), p. 29

Table App- 12. California and New York State NOx emissions regulations

California Air Resources Board (CARB) Standards

Year		*NOx (lb/MWh)*
2003	without CHP	0.5
2003	with CHP	0.7
2007	all	0.07

New York State Department of Environmental Conservation (NYSDEC), through the Division of Air Quality

Current Regulations

Combustion Turbines

	ppm, dry volume, corrected to 15% oxygen	*NOx (lb/MWh)*	
Simple Cycle	50	2.5	*approximate*
Combined Cycle	42	2.4	*approximate*

Reciprocating Engines

larger then 200 hp (150 kW) in severe nonattainment area, 400 hp (300 kW) elsewhere

	NOx (g/bhp-hr)		*NOx (lb/MWh)*	
	until March 31, 2005	*after April 1, 2005*	*until March 31, 2005*	*after April 1, 2005*
rich burn recip	2	1.5	5.9	4.4
lean burn recip				
spark-ignite	3	1.5	8.9	4.4
compression-ignite	9	2.3	26.6	6.8
landfill or digester gas	9	2	26.6	5.9

Proposed DG Rule (sent to Governor's office in January 2005)

Systems installed prior to May 1, 2005

Effective January 1, 2008

	limit	*units*	*NOx (lb/MWh)*	
Microturbines	1.6	lb/MWh	1.6	
Natural gas turbines	50	ppm volume	2.5	*approximate*
Diesel turbines	100	ppm volume	5	*approximate*
Natural gas ICE (lean burn)	3	g/bhp-h	8.9	
Natural gas ICE (rich burn)	2	g/bhp-h	5.9	
Diesel ICE	9	g/bhp-h	26.6	

note: equipment running on biogas has different limits,
coming into effect Janunary 1, 2010

Systems installed after May 1, 2005

	NOx (lb/MWh)		
	Systems installed after May 1, 2005	*Systems installed after January 1, 2009*	*Systems installed after January 1, 2010*
Biogas under 180 kW	none	4.4	4.4
Biogas over 180 kW	4.4	4.4	4.4
All other sources	1.6	1.6	1.6

Appendix F. Recent Modifications to DER-CAM

DER-CAM, described in detail in Siddiqui (2003), was used for a case study to see how computer simulated modeling and decision-making compared to that of actual DG adopters (Bailey, 2003). Based on findings from several case studies the following modifications were made to DER-CAM for this and other recent projects:

- **Minimum load constraints**: all electricity generation equipment except PV was constrained to operate between minimum and full load, or not at all, during any hourly timestep.
- **Effect of DG reliability on demand charges**: demand charges were based on the statistically expected charge for each month or day (monthly or daily demand), rather than on the assumption of 100% reliability. The expected maximum demand depends on the number, capacity, and reliability of generators installed.
- **Payback period**: a maximum payback period constraint was included on all investments. In practice, most economically motivated adopters would not consider solutions with long payback periods, even if savings were maximized.
- **Monthly pricing**: electricity pricing was changed from seasonal to monthly to represent New York State energy rates more accurately.
- **Multiple natural gas rates**: natural gas rates were changed from a single monthly rate (fixed and volumetric components) to three separate rates for typical, air-conditioning, and DG, because some New York utilities offer different rates for different end uses.