Clean Distributed Generation Performance and Cost Analysis

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Disclaimer

This report forecasts cost and performance for ultra-clean CHP technologies. The California Air Resources Board Guidelines, East Texas Regulations and the RAP Model Rule were used as benchmarks against which the ultra-clean CHP technologies were compared. The technology profiles developed over the course of this study represent a composite of work sponsored by The Energy Foundation, DE Solutions' staff project experience, input received from a number of CHP stakeholders, and the recently completed study by the National Renewable Energy Laboratory "Gas Fired Distributed Energy Resource Technology Characterizations". The collection of input received by the stakeholders, with varying technical perspectives and many with competitive and regulatory agendas, resulted in a wide variation of inputs, many of which were not fully recognized in this study. Thus, the individual views of the aforementioned stakeholder participants are not necessarily reflected in this report.

Executive Summary

This assessment examined the performance, cost and timing of ultra-low emissions CHP technologies driven by certain air quality regions in the U.S. The technologies considered in this assessment were natural gas fueled industrial gas turbines, reciprocating engines, microturbines and fuel cells in the 75 kW to 10 MW size range. The CHP technology and cost projections were overlaid on three time-phased emission regulation models for CHP: California Air Resources Board (CARB), East Texas, and the RAP Model Rule which is being considered by several New England States.

A brief summary of the ultra-low emission version of each of these technologies follows:

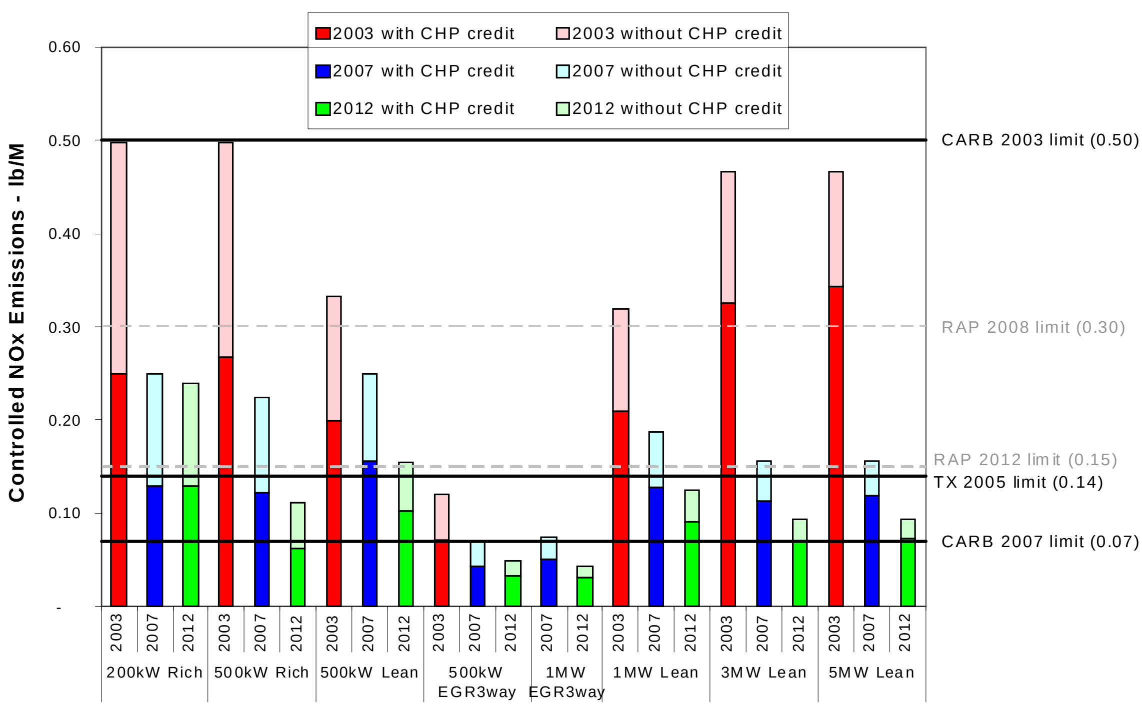
- **Gas Turbines –** Currently requires expensive after-treatment (SCR) to meet ultra-low levels. Dry Low emission (DLE) combustors show potential for single digit ppm NOx, but not low enough to avoid SCR. Catalytic combustion and other surface combustion techniques can achieve ultra-low emission signatures more cost-effectively than SCR but require time and resources to get there. The exception to the above are recuperated gas turbines equipped with DLE combustors, which have potential to achieve ultra-low levels without after-treatment.
- **Reciprocating Engines –** Lean burn engines face the biggest challenge to achieve ultra-low emission levels. Lean limits need to be extended with enhanced combustion techniques along with significant advancements in SCR effectiveness. Rich burn engine technology can probably be stretched to reach the ultra-low levels in CHP applications with more precise fuel/air ratio controls and enhanced catalyst formulations. However, the most promising approach to minimal emissions for reciprocating engines is the use of exhaust gas recirculation with a 3/way catalyst. Although not yet commercially mature, the approach looks to provide a negligible emission solution without appreciably impacting system cost or efficiency.
- **Microturbines –** DLE combustors appear capable of meeting super clean requirements at full-load conditions. However, regulations requiring low emissions over a wide range of loads regardless of the operating strategy could prove problematic for this approach. And the push to higher efficiencies via higher turbine inlet temperatures and pressure ratios will place additional stress on clean DLE technology to keep pace. Catalytic or surface combustion appears to be the backup approach, but little if any development work is underway.
- **Fuel Cells –** Very low emission signatures are an inherent attribute. Another advantage is high electric efficiency potential. Fuel cells need to realize significant reductions in cost, without which market acceptance will be very limited.

The technology profiles that were developed for each technology and size in the years 2004, 2007, and 2012 respectively were stacked up against the three regulatory models, each of which includes a credit method for heat utilization. We will key on reciprocating engines and NOx control in the Executive Summary, as they face the biggest challenge and present the largest opportunity for emissions improvement. Findings for the other technologies and emission constituents will be summarized with details provided in the main report sections.

Figure 1 below, illustrates the NOx signature for lean burn engines with SCR, rich burn engines with 3-way catalysts, and EGR engines with 3-way catalysts. In addition to today's emission performance, emission levels are projected in the base case scenario for 2007 and 2012. The top bars represent the emission out of the CHP system without any credit provided for heat recovery. The bottom bars represent emission levels with credit given for heat recovery using the CARB and Texas method. The dark lines correspond to the CARB and East Texas levels. The lighter dashed lines represent the RAP model levels, but as RAP uses a different heat use credit method, the bottom bars don't exactly apply.

As depicted, by 2007 rich burn and lean burn engines are projected to meet East Texas requirements in CHP applications where a heat use credit can be applied. It's a tougher call for CARB 2007 with 2012 being a more probable date for achievement of ultra low levels. On the other hand, engines equipped with EGR and 3-way catalysts show promise to meet these ultra-low levels by 2007. It is likely though, that the number of engine manufacturers offering EGR with 3-way catalysts and proven product sizes ready for the market by 2007 will be limited.

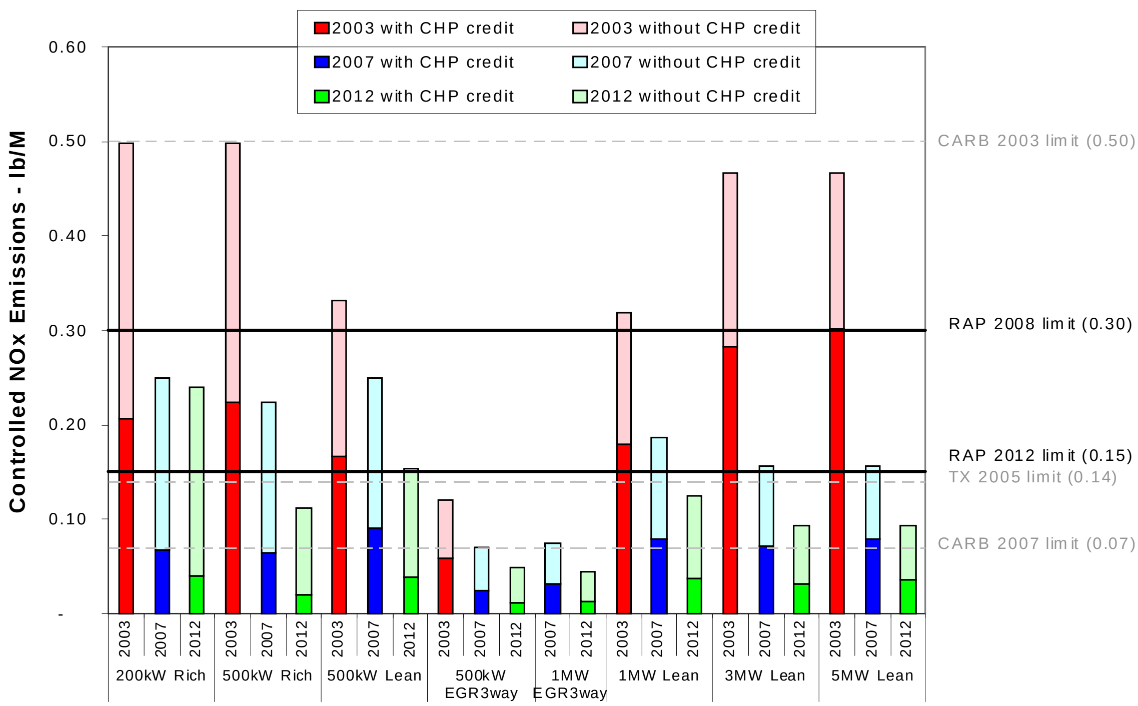
Figure 1 - Reciprocating Engine NOx Signatures against CARB Guidelines and East Texas Standards



CARB and Texas calculate the heat recovery credit on a straight BTU to kWh conversion (3.4 MMBTU = 1 MWh). So the emissions from a CHP system is divided by the sum of the electric kWh output and the thermal kWh output to get the emission rate. The RAP

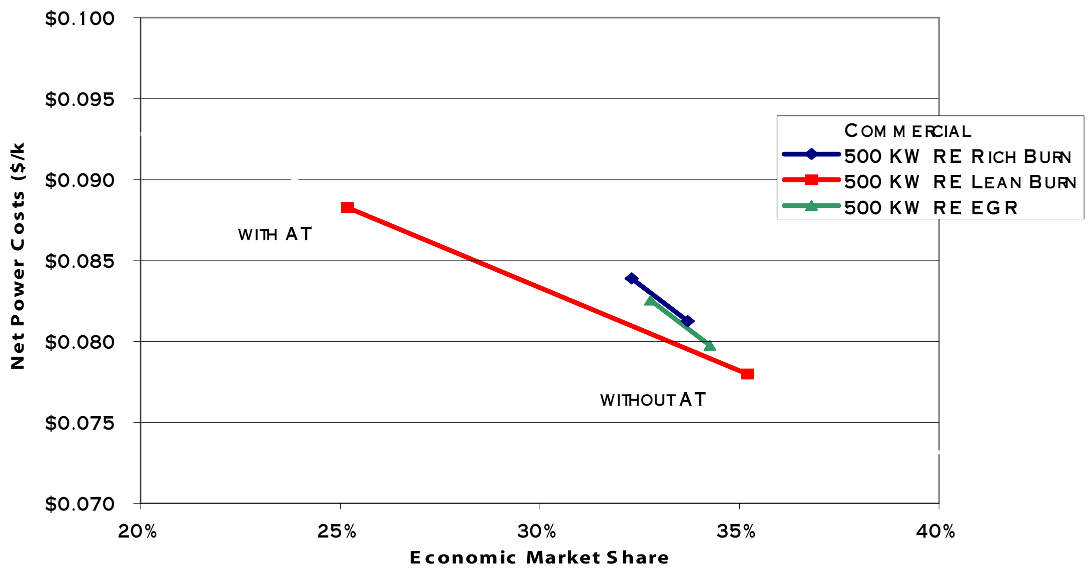
Model Rule credits the actual emissions offset from the boiler. We used Connecticut's new boiler standard (0.2 lb/MMBTU fuel input) for the analysis as Connecticut is farthest along with a draft DG regulation patterned after the RAP rule. The results of the analysis are shown in Figure 2 below. As shown, although the gross emission rates don't change, the net emissions after the offset with the RAP method is lower than with the CARB/Texas method. The results can vary significantly depending on the assumed boiler emission rate.

Figure 2 - Reciprocating Engine NOx Signatures against the RAP Model Rule



Life cycle costs were calculated for each of the technology cases and measured against commercial and industrial electric prices by State to approximate the economic market potential for each CHP scenario considered. Although not an exact science, the technique provides an indication of market disparity between various alternatives. Figure 3 below compares the lean burn, rich burn and EGR 500 kW reciprocating engine options in the 2007 base case scenario. Economic market indicators are provided for each technology with and without after-treatment. As shown, after-treatment negatively impacts the reachable market share in all cases but is most dramatically impacted by the lean burn engine that requires SCR. So, not only is the challenge to reach the ultra-low emission levels more problematic with lean burn SCR, the reachable market is reduced by 29% because of SCR costs vs. a 6% impact from a 3-way catalyst on an EGR engine system.

Figure 3 - Economic Market for Reciprocating Engine (RE) Technologies With and Without After-Treatment (AT)



The impact of SCR on Turbine economic market size is not as large as for a lean burn engine, but is nevertheless significant. The economic and market benefits of finding alternatives to SCR or in time phasing the regulations to avoid SCR would be substantial.

The environmental advantage of fuel cells over alternative technologies no longer justifies big cost premiums given that the other technology options are keeping pace with the environmental ratcheting and doing so more cost effectively. The price premium for fuel cells needs to be justified on higher electric efficiencies, the resulting lessened dependence on heat utilization, infrequent maintenance intervals and aesthetic features.

Likewise, microturbines must increase efficiency and reduce cost to improve their economic position. Any additional cost penalties for environmental compliance will further hinder their market acceptance.

Clean CHP provides numerous benefits to energy consumers and to the utility system. Overreaching environmental requirements can hinder CHP implementation and deny the market of CHP's economic, environmental and system advantages. The potential is there for all CHP technologies to reach ultra-low emission levels. Reasonableness in setting emission requirements (full and part-load), schedules, and compliance protocols is in order for the ultimate benefits of CHP to be realized.

Table of Contents

Acknowledgements i
Disclaimer ii
Executive Summary iii
Introduction 1
Clean CHP Technologies 3
  CHP Heat Quality 7
Clean CHP Performance and Cost Profiles 9
  Technology Profiling Process 9
  Scenario Development 10
  Base Case Technology Scenario Summary 11
  Technology Drivers 12
Economic Implications 15
  CHP Economic Findings 16
  Market Sensitivity 22
Regulatory Assessment 26
  Overview of Regulatory Models 26
    CARB 26
    RAP 26
    East Texas 27
  Effect of Regulatory Models on Emission Levels 27
    NOx 27
    Carbon Monoxide 32
    VOCs 36
Reciprocating Engine Exhaust Gas Recirculation with 3-Way Catalyst Roadmap 38
  Current State of EGR/3-Way Technology 39
  Technology Description 40
  Technology Barriers 41
    Research, Development and Testing Needs 41
    Performance and Cost Targets 43
Conclusions 44
  Gas Turbines 44
  Reciprocating Engines 44
  Microturbines 44
  Fuel Cells 44
Recommendations 46
References 47
Appendix A 49
  Sample Data Sheets 49

Tables

Table 1 – Assumptions for All Systems 16
Table 2 - Assumptions by System Size.. 16
Table 3 - CARB Emissions Standards (lb/MWh)... 26
Table 4 - RAP Emissions Standards (lb/MWh).. 27
Table 5 - Market Needs and Technology Solutions... 42
Table 6 - Recommended Performance and Cost Targets.. 43

Figures

Figure 1 - Reciprocating Engine NOx Signatures against CARB Guidelines and East Texas Standards iv
Figure 2 - Reciprocating Engine NOx Signatures against the RAP Model Rule v
Figure 3 - Economic Market for Reciprocating Engine (RE) Technologies With and Without After-Treatment (AT) vi
Figure 4 - Technology Size Coverage 3
Figure 5 - Heat Quality Comparison.. 8
Figure 6 - Base Case Efficiency Projections (Selected < 1 MW Technologies) 11
Figure 7 - Base Case Efficiency Projections (Selected > 1 MW Technologies) 11
Figure 8 - Capital Cost and Efficiency Projections (Selected < 1 MW Technologies).... 12
Figure 9 - Capital Cost and Efficiency Projections (Selected > 1 MW Technologies).... 12
Figure 10 - Small Reciprocating Engine Net Power Costs -- Base Case......................... 16
Figure 11 - Large Reciprocating Engine Technology Net Power Costs -- Base Case 17
Figure 12 - Microturbine Technology Net Power Costs -- Base Case 17
Figure 13 - Gas Turbine Technology Net Power Costs -- Base Case.............................. 18
Figure 14 - Fuel Cell Technology Net Power Costs -- Base Case.................................. 19
Figure 15 - Selected Technologies -- Base 2007 Gas Price Sensitivity........................... 19
Figure 16 - Selected Technologies -- Base 2007 Heat Utilization Sensitivity 20
Figure 17 - Selected Technologies -- Base 2007 Load Factor Sensitivity....................... 20
Figure 18 - Scenario Comparisons of Net Power Costs -- Selected 1 MW Class 21
Figure 19 - Scenario Comparisons of Net Power Costs -- Selected 10 MW Class Technologies.. 21
Figure 20 - Average Electric Rate by Market Share... 22
Figure 21 - Estimating Competitive Market Share 22
Figure 22 - Small Reciprocating Engine Technology Economic Market Share............... 23
Figure 23 - Microturbine Technology Economic Market Share...................................... 23
Figure 24- Large Reciprocating Engine Technology Economic Market Share................ 24
Figure 25 - Gas Turbine Technology Economic Market Share....................................... 24
Figure 26 - Market Comparison for Selected Engines -- With and Without Aftertreatment Costs - 2007 Base Case.. 25
Figure 27 - Market Share for 3 MW Class GT -- With and Without Aftertreatment Costs - 2007 Base Case 25
Figure 28 - NOx Emissions for Reciprocating Engines, CARB and TNRCC.................. 28
Figure 29 - NOx Emissions for Microturbines and Gas Turbines, CARB and TNRCC.. 29
Figure 30 - NOx Emissions for Fuel Cells, CARB and TNRCC..................................... 29

Figure 31 - NOx Emissions for Reciprocating Engines, RAP 30
Figure 32 - NOx Emissions for Microturbines and Gas Turbines, RAP 31
Figure 33 - NOx Emissions for Fuel Cells, RAP 31
Figure 34 – Sensitivity of RAP CHP Credit to Boiler Offset Allowance (lb/MMBTU) - 500 kW Lean Burn Engine 32
Figure 35 - CO Emissions for Reciprocating Engines, CARB 33
Figure 36 - CO Emissions for Microturbines and Gas Turbines, CARB 33
Figure 37 - CO Emissions for Fuel Cells, CARB 34
Figure 38 - CO Emissions for Reciprocating Engines, RAP 35
Figure 39 - CO Emissions for Microturbines and Gas Turbines, RAP 35
Figure 40 - CO Emissions for Fuel Cells, RAP 36
Figure 41 - VOC Emissions for Reciprocating Engines, CARB 36
Figure 42 - VOC Emissions for Microturbines and Gas Turbines, CARB 37
Figure 43 - VOC Emissions for Fuel Cells, CARB 37
Figure 44 - Comparison of Engine NOx Control Systems 38
Figure 45 - EGR/3-Way Schematic 40

Introduction

In 2002, The Energy Foundation sponsored a study to assess the current and projected costs of distributed generation (DG) and combined heat and power (CHP) technologies relative to the *CARB Guidance for the Permitting of Electrical Generation Technologies* and the *CARB Rulemaking to Establish a Distributed Generation Certification Program*.

Projections were made for cost and performance of representative DG and CHP technologies with ultra-clean emission control over a ten-year period. The emission benchmarks used to characterize these technologies were the CARB Guidelines for 2003 and 2007. A White Paper resulted that defined the range of cost trajectories for various DG emissions control technologies and the factors (like manufacturing economies, materials science breakthroughs, etc.) that might drive DG and CHP technologies toward one end of the range or the other.

This effort provided a perspective for stakeholders to start evolving a realistic emission improvement program that balances potential market setbacks against CHP's many long-term social benefits. The Energy Foundation study was a step toward developing a common technology understanding that can lead to the adoption of responsible DG/CHP emission control strategies.

In 2003, Oak Ridge National Laboratory (ORNL) and The Department of Energy (DOE) initiated a follow-on effort to more broadly examine the environmental, technology and cost tradeoffs of CHP. A number of complementary objectives were targeted:

- A more comprehensive profiling of CHP and after-treatment technologies and suppliers
- Engagement of CHP stakeholders toward a common understanding of technology development scenarios
- Assessment of economic and market implications of ultra-clean CHP
- Technology Roadmap for new promising concept(s) to achieve ultra-clean levels without big performance or cost penalties.

This assessment endeavors to evolve a better understanding of CHP technology, economics, market effects, and realistic timeframes to maximize CHP's social and market impact. The Clean DG Assessment included the following tasks:

<u>CHP Technology Profiles</u>
Based on stakeholder feedback, the technology profiles developed initially for The Energy Foundation assessment were augmented with a broader array of sizes, equipment types, and environmental cleanup options. The data sheet format developed for the Energy Foundation work was used as the template for this effort. New technology additions included a small rich-burn reciprocating engine (200 kW), coverage of

reciprocating engines with exhaust gas recirculation and 3-Way catalysts, a hybrid fuel cell (1 MW), a mid-size turbine (5 MW), and a 4 MW recuperative turbine.

Stakeholder Involvement

A broad swath of DG stakeholders was engaged to ensure that all viable and potentially significant technology options are fairly characterized along with performance and cost potential, ranges, risks, timeframes, and resource requirements. The participation process began with a compilation of key stakeholders and an e-mail transmittal of appropriate data sheets and initial assumptions. Follow-up phone calls, e-mail exchanges, and technology-specific conference calls followed until relevant input and concerns were factored into the study.

Economic Analysis

Based on the updated technology and cost profiles, a life cycle cost analysis was performed on the technology portfolio for each of the three time frames. An economic and market sensitivity screen was conducted to gauge the market impacts of selected technologies and economic variables.

Regulatory Assessment

The findings were overlaid onto representative State environmental regulations and proposals: Regulatory Assistance Project (RAP) Model Emissions Rule, CARB 2007 and East Texas 2005.

Clean DG Technology Roadmap

A Technology Roadmap was drafted for reciprocating engines with exhaust gas recirculation and three-way catalyst.

Clean CHP Technologies

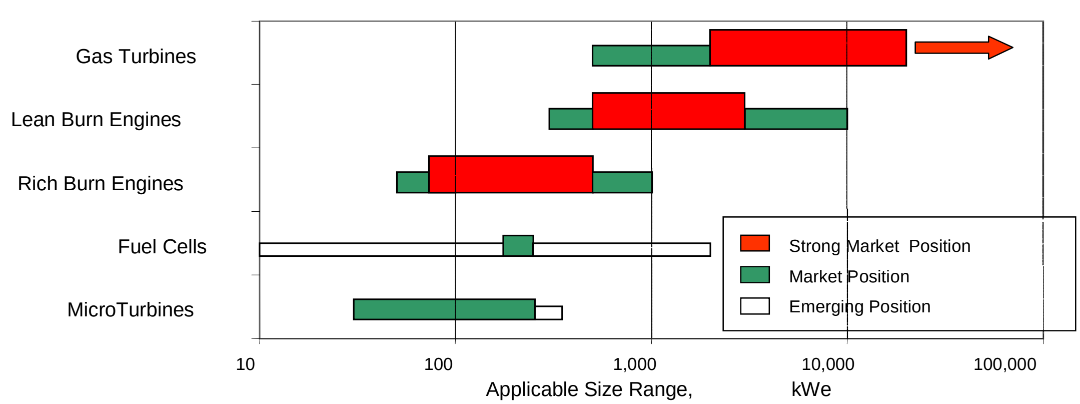
Most notable technology options available today for CHP include industrial and aero-derivative gas turbines, reciprocating engines, microturbines and fuel cells. The primary fuel option for these technologies is natural gas because of its availability, cost and emission qualities. Other fuel sources include landfill gas, digester gas, industrial waste fuel streams, propane, and diesel fuel. This study looked only at natural gas CHP applications.

Reciprocating engines and gas turbines have been used for decades in power generation and CHP applications. State-of-the-art technology evolved over decades of technology maturity and market experience. They have also benefited from the production base and technology investments for transportation, marine and aerospace applications.

Microturbines have become commercially available for CHP applications within the last five years and fuel cells are emerging in the marketplace primarily through pre-commercial offerings. Product sizes are currently limited as are the number of manufacturers. Today's prices are generally above the market-clearing price, and currently require manufacturer, government or utility price support for market acceptance. With technology and market maturity, these technologies show potential for significant improvements in both cost and performance.

The inventory of operating CHP capacity in the U.S. is approximately 77 GW[1], with 90% in the industrial sector. Gas turbines and combined cycle units account for a majority of the capacity (66%), while reciprocating engines dominate the number of installations (46%). The size span for the various CHP technology classes is depicted in Figure 4. Also noted are the market dominant technologies by size class.

Figure 4 - Technology Size Coverage



[1] Source: Energy and Environmental Analysis, Inc.

Each of these technologies is summarized below with emphasis placed on ultra-low emission systems. Also, output based metrics will be used when discussing emission levels to stay consistent with the movement at State and Federal environmental agencies.

Gas Turbines (500 kW to 15 MW)

Industrial gas turbines are an established technology used for a variety of on-site generation and mechanical drive applications. Gas turbines are most competitive in sizes larger than 3 MW in combined heat and power (CHP) applications. Gas turbines excel in applications with high heat requirements. In order to achieve higher electric conversion efficiencies, turbine technology is pushed to higher pressure ratios and higher turbine inlet temperatures, both of which exacerbate NOx formation. State of the art gas turbines control emissions using lean pre-mix combustion techniques. These combustors are often referred to as dry low emission (DLE) combustors. Most turbine products (with the exception of many of the smaller turbines (< 3 MW) are equipped with DLE combustors capable of 25 ppm NOx today. By 2007, most turbines are expected to be equipped with DLE combustors in the 15 ppm range @ 15% O2 (0.68 lb/MWh @ 28% HHV efficiency). Lower emission levels, like those currently specified by SCAQMD, typically require exhaust treatment such as selective catalytic reduction (SCR) to meet the NOx levels. According to turbine and SCR system suppliers, current capital costs (equipment, installation and startup) for SCR are around $130/kW for 3 – 5 MW systems, and $100/kW for larger systems (10 – 15 MW). An oxidation catalyst will be required to meet 2007 CO and VOC requirements, which will add expense, but with expected SCR cost improvements overall after-treatment costs should stay close to the current levels. Catalytic combustion, which has the capability to reach these lower emission levels without after-treatment, is now being introduced in selected turbine products (Kawasaki 1.5 MW and GE 10 MW). Price premiums for these combustors are currently market-based and priced at 10 to 20% discounts below that for SCR systems. Long-term, with increased volumes and competition, the cost for catalytic combustors should drop significantly.

Recuperated gas turbines, up until recently a configuration unique to microturbines, are now being developed in multi-megawatt sizes. Solar Turbines announced the commercial availability of a 4 MW recuperated Mercury turbine in December 2003. Recuperated turbines operate at lower pressure ratios and combustor temperatures easing NOx formation. Recuperated turbine DLE combustors show potential to meet ultra-low emission levels without any after-treatment.

Reciprocating Engines (30 kW to 5 MW)

Natural gas fueled reciprocating engines (engines) offer low first cost, easy start-up, proven reliability when properly maintained, and good load-following characteristics. Engines are well suited for packaged CHP in commercial and light industrial applications less than 5 MW. Natural gas engines for power generation currently rely on spark ignition (SI) to combust the fuel. Historically, there have been two types of SI engines: rich-burn and lean-burn.

Rich-burn engines generate relatively high levels of NOx (35 - 40 lbs/MW-hr) but are readily treated with passive 3-way catalysts similar to that used in automobiles. With a properly sized and controlled system, these catalysts can achieve emission reductions greater than 99%. These catalysts are relatively inexpensive ($30 – 40/kW) and are fairly reliable. Rich-burn engines with 3-Way catalyst systems can reach the toughest standards currently on the books (NO_x - 0.5 lb/MW-hr). Lower levels have reportedly been achieved in the lab with fresh catalysts by some organizations. Field experience with lower NOx levels is limited as are further advancements to this relatively mature technology.

Lean-burn engines are inherently more efficient, more powerful, less maintenance intensive, and produce considerably fewer pollutants than rich-burn engines. Depending on the size and vintage of the engine, engine-out NOx levels range from 2.0 to 3.0 lb/MWh. In order to meet current requirements in stringent environmental regions such as California, a relatively expensive SCR system and oxidation catalyst is required. The cost of an SCR system varies by engine size, quantity and market conditions. Typical prices for a 90% effective SCR system would be $130/kW for a 3 MW engine and $170/kW for a 1 MW engine. Prices go up significantly for engine sizes less than 1 MW. An Oxidation catalyst for CO and VOC reduction would add another $30/kW. Closed loop feedback controls can incrementally improve NOx effectiveness beyond these levels while controlling ammonia slip for added cost and complexity, but field experience is limited.

With support from the California Energy Commission and DOE, a new approach to low emission levels is showing promise. In principle, the concept lends the best features of rich-burn and lean-burn technology. Exhaust gas recirculation (EGR) is used instead of excess air. This enables higher efficiency and lower engine-out emissions approaching the characteristics of lean-burn technology. With the engine exhaust containing very little O_2, a lower cost and very effective 3-way catalyst can be used to reduce emissions. Lab tests have shown the ability to approach the 2007 level mandated by CARB and proposed by the Coalition when using fresh catalysts and controlled conditions. Several companies have introduced EGR/3-Way products into the market but are not yet willing to warrant emission performance at the CARB 2007 levels. Areas of uncertainty include ignition system robustness, catalyst deterioration, and EGR induced engine wear and durability concerns. Further discussion of this technology can be found in a dedicated section beginning on page 45 of this report.

Other technologies that are still in early stages of development but that may enable yet lower emission levels include hydrogen fuel augmentation, laser ignition, micro-pilot ignition, homogeneous charge compression ignition (HCCI), and NO_x absorption systems. It is doubtful that these technologies would be ready commercially within the next five years. EGR/3-Way technology appears to offer the most near-term and cost-effective solution for ultra-low emission levels.

Microturbines (30 kW to 250 kW)

Several companies (Capstone, Ingersoll Rand, Bowman, Elliott) have developed commercial microturbine (MT) products, ranging in size from 30 kW to 250 kW, and are in the early stages of market entry. Microturbines' potential for low emissions, reduced maintenance and simplicity could make on-site generation more palatable for many smaller commercial and industrial operations if plans for cost reduction are realized.

MTs incorporate recuperation to recoup some of the inefficiencies inherent with small-scale turbo-machinery. Recuperated turbines are lower pressure ratio machines and operate at lower turbine inlet temperatures than their simple cycle turbine counterparts. Both of these features lessen emission formation. At full-load, MTs equipped with DLE combustors exhibits potential to reach the ultra-low levels without the need for any after-treatment.

Ultra-low levels with DLE combustors are achievable over a relatively narrow load range. This is a characteristic of electric efficiencies as well. MTs are most cost-effective and can produce very low emissions when operated near or at full-load. Emission regulations that require ultra-low emissions over a wide-load spectrum regardless of the economic operating strategy will be problematic for MT DLE combustors. Exhaust after-treatment on small MTs, if required, would likely debilitate MT economics.

Fuel Cells (10 kW to 3 MW)

Fuel cell systems with applications in electric power generation, motor vehicles, portable electronic equipment and military/aerospace applications are largely in research, development, testing and other pre-commercialization stages. Fuel cells produce power electrochemically, more like a battery than like a conventional generating system. Unlike a storage battery, however, which produces power from stored chemicals, fuel cells produce power when hydrogen fuel is delivered to the anode of the cell and oxygen in air is delivered to the cathode. The resultant chemical reactions at each electrode create a stream of electrons (or direct current) that flows between the oppositely charged electrodes of the cell. The hydrogen fuel can come from a variety of sources, but the most economic is through reforming of natural gas, which is generally the only source for fuel cell emissions.

There are several different liquid and solid media that can be used to create the fuel cell's electrochemical reactions – phosphoric acid (PAFC), molten carbonate (MCFC), solid oxide (SOFC), and proton exchange membrane (PEM). Each of these media comprises a distinct fuel cell technology with its own performance characteristics and development schedule. PAFCs are in early commercial market development with 200 kW units delivered to over 200 customers worldwide. Industry insights imply that PAFC products are being phased out in favor of other fuel cell technologies. The SOFC, MCFC, and PEM technologies are now gaining development support and are in field test or pre-commercial demonstration stages.

Fuel cells promise higher electric efficiencies than generation technologies based on prime movers such as recip engines or turbines. In addition fuel cells are inherently quiet and extremely clean running. Like microturbines, fuel cells require power electronics to convert direct current output to 60-Hz alternating current. Many fuel cell technologies are modular and capable of application in small commercial and even residential markets; other technologies utilize high temperatures in larger sized systems that would be well suited to industrial CHP applications. Fuel cell installations to-date have benefited by government support to counter current high costs. Otherwise, markets have been limited to niche markets such as very high electric rate areas requiring near zero emissions, and in some high power reliability applications. Substantial price reductions are necessary for meaningful market acceptance to occur.

CHP Heat Quality

Heat utilization is important to high overall efficiencies and good economics. Affecting heat utilization are a number of factors including site thermal load profile, temperature (Quality) of heat required by site, and CHP technology characteristics. The heat characteristics of the four CHP technologies considered in this report are briefly discussed below:

- Industrial gas turbines (simple cycle), with most of the rejected heat in the exhaust at temperatures in the vicinity of 900^{o}F, have very good quality heat which can be used for most applications including high temperature steam industrial processes and double effect absorption cooling.

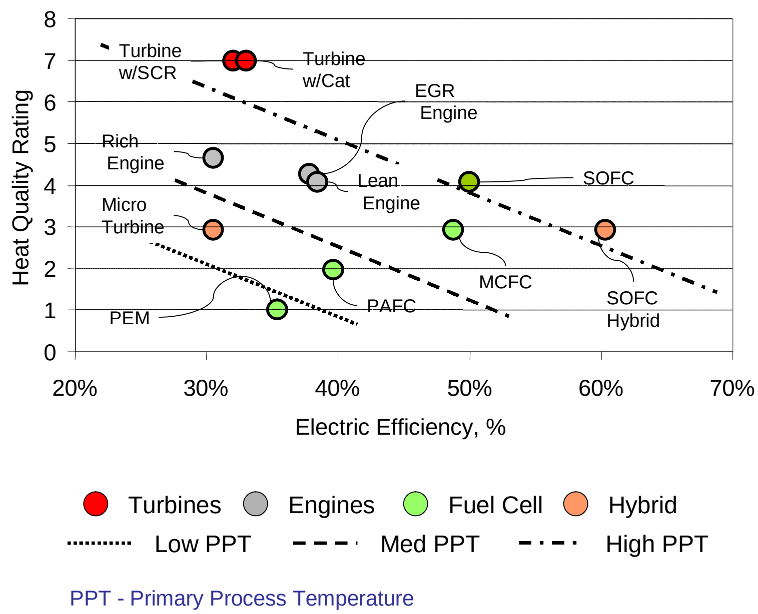
- Recuperated gas turbines, including the 4 MW Mercury and microturbines, uses the high temperature exhaust to preheat the combustion air, increasing electric efficiency but decreasing the exhaust temperature which reduces the amount of heat available for higher temperature applications. Microturbine exhaust temperatures are around 500^{o}F. The exhaust temperature for the Mercury is in the vicinity of 700^{o}F.

- In reciprocating engines the recovered heat is typically split between the exhaust at temperatures between 900^{o}F and 1,000^{o}F, and the jacket coolant, which is usually kept below 220^{o}F. Lower grade heat is also available in some engines from the after-cooler and the lube oil cooler. So, engines can provide most of the available heat at hot water temperatures between 220^{o}F and 230^{o}F, or it can provide high-grade steam using only the exhaust heat.

- Fuel cell heat quality is linked to the primary process temperature and the degree of internal heat recovery for reformer heating and/or electric bottoming cycles. The heat characteristics of fuel cells vary by technology but are generally lackluster. Either the quantity of available heat is low because of the emphasis placed on electric efficiency or the temperature of the heat is low, limiting heat applicability.

The quality of heat vs. electric efficiency for the range of CHP technologies is shown in Figure 5 below. There are three primary factors influencing the characteristics of the heat. The first is the primary process temperature (PPT). The second is the electrical efficiency of the system, where the higher the electric efficiency the lower the amount of heat available. And the third is use of heat for bottoming cycles (SOFC Hybrid) or recuperation.

Figure 5 - Heat Quality Comparison



Clean CHP Performance and Cost Profiles

Each of the four technology classes is on ever-changing performance and cost trajectories that are affected by a number of market, institutional and technical factors. Major factors include:

- Level of DG market activity, trends and outlook.
- Policy and regulatory foundation including interconnect standards, utility tariff structures, grid enhancement monetization, and technology forcing regulations
- Technology initiatives and resources
- Fuel rate structures for CHP

Technology Profiling Process

Representative product sizes for each technology class were selected to project cost and performance characteristics. Exhaust after-treatment is added as necessary and practical to meet or approach the ultra-clean out-year levels established by some States. Technology profiles developed for The Energy Foundation in 2002 and the 2003 NREL Distributed Energy Technology Characterization Report were used as starting points for the profiling process. Additional information was obtained from CHP manufacturers, distributors, packagers, technology developers, R&D organizations, and after-treatment suppliers on the current state of Clean CHP technology and projections over the next eight years. The data profiles covered installed cost, O&M cost, efficiency, and emissions. For technologies with after-treatment, the incremental cost and emission improvement were detailed separately.

The technology and product sizes profiled are summarized below:

- Natural Gas CHP Turbines
    - 3 MW, 5 MW and 10 MW with DLE combustor, SCR and oxidation catalyst
    - 3 MW and 10 MW with Catalytic Combustion
    - 4 MW Recuperated Gas Turbine
- Natural Gas CHP Reciprocating Engines
    - 200 kW and 500 kW rich-burn with 3-way catalyst
    - 500 kW, 1 MW, 3 MW and 5 MW lean-burn with SCR and oxidation catalyst
    - 500 kW and 1 MW engines with EGR and 3-way catalyst
- Natural Gas CHP Microturbines
    - 75 kW
    - 250 kW
- Natural Gas CHP Fuel Cells
    - 200 kW PAFC
    - 200 kW PEM
    - 100 kW SOFC
    - 250 kW and 2 MW MCFC
    - 1 MW hybrid SOFC-Turbine

Scenario Development

For each of the three time periods analyzed (2004, 2007 and 2012), a scenario analysis was conducted to better frame the future results. For 2004, a typical value for each parameter was tabulated noting that variation in product performance and application, and installation complexity occurs in the marketplace. For 2007 and 2012, three values were projected to represent a span of technology and market development scenarios: limited, base, and accelerated cases. In general, each of these cases is characterized by:

- Limited
  - Market and economic conditions for CHP stagnate or erode.
  - Restricted public and private funds for technology development
  - Minimal competition between technologies and among manufacturers
  - No monetary or regulatory recognition of grid benefits
- Base
  - Continuation of current trends to gradually improve technology
  - Moderate recognition of CHP benefits by policy and regulatory communities
  - Gradual utility acceptance of CHP
  - Continuation of Government support for CHP technology
  - Increased regional requirement for ultra-low emission CHP products
- Accelerated
  - Favorable policy and regulatory treatment of CHP
  - Capacity, T&D constraints and reliability concerns become more acute
  - Recognition and monetary quantification of CHP benefits
  - Robust market activity and competition
  - Robust investment in technology by the government and by private industry
  - Strong momentum worldwide for lower CHP emissions and universal standards

A detailed profile (data set) was developed for each of the twenty-two technologies under each of the three scenarios. The data sets consisted of cost, performance, and emissions of systems with and without after-treatment or advanced combustion technologies. Representative data sheets are provided in Appendix 1. This data set was then used to calculate CHP life cycle costs. The emissions data was compared against the three regulatory benchmarks to determine if the system would satisfy these requirements in both the electric-only and in CHP applications. All costs are in current year (2003) dollars. Again, as noted in the disclaimer, these data sheets represent a composite of input received and do not necessarily represent a consensus view or individual perspectives of the stakeholders.

Base Case Technology Scenario Summary

For representative technologies, Figures 6 and 7 show the expected improvement in installed capital costs through 2012 for the base case scenario. All technologies have potential for efficiency improvement.

Figure 6 - Base Case Efficiency Projections (Selected < 1 MW Technologies)

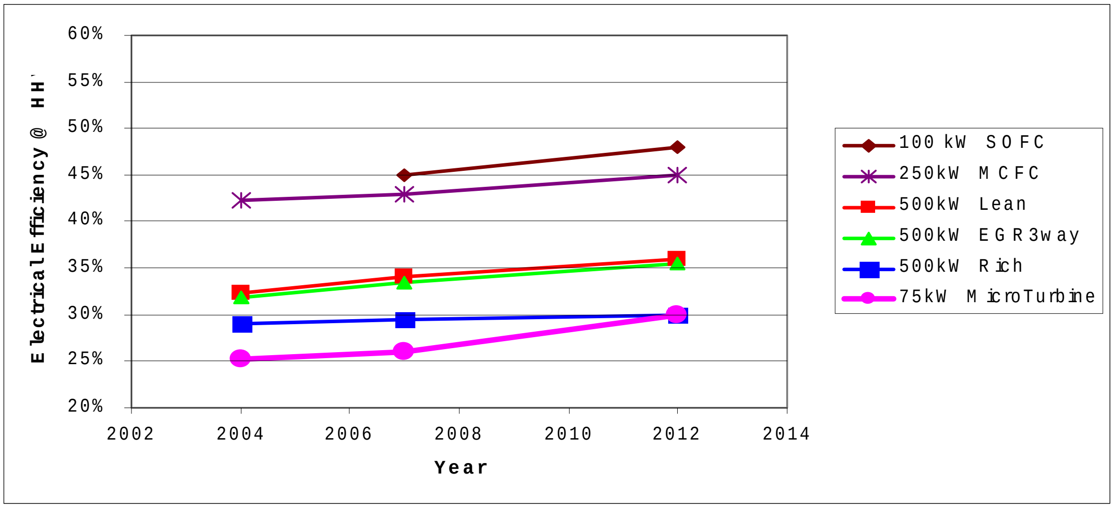
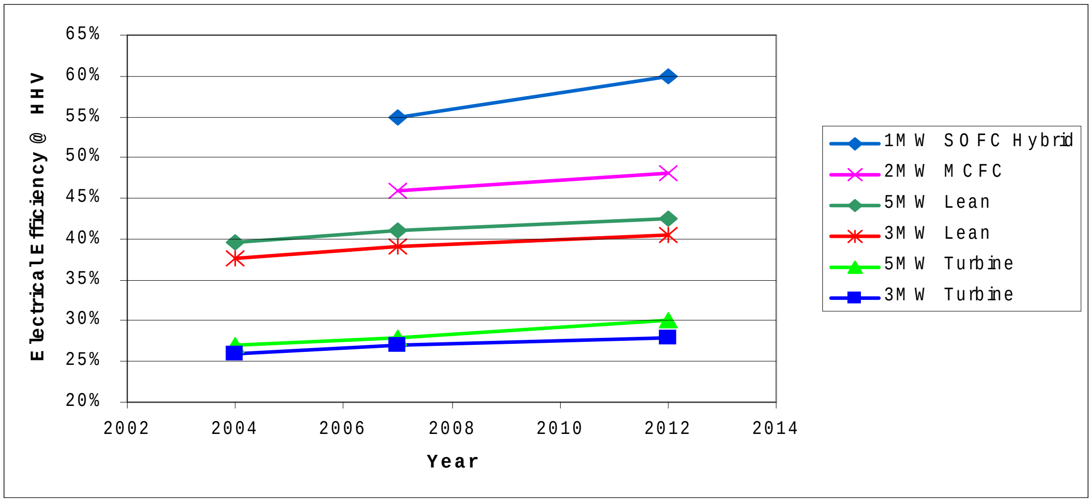


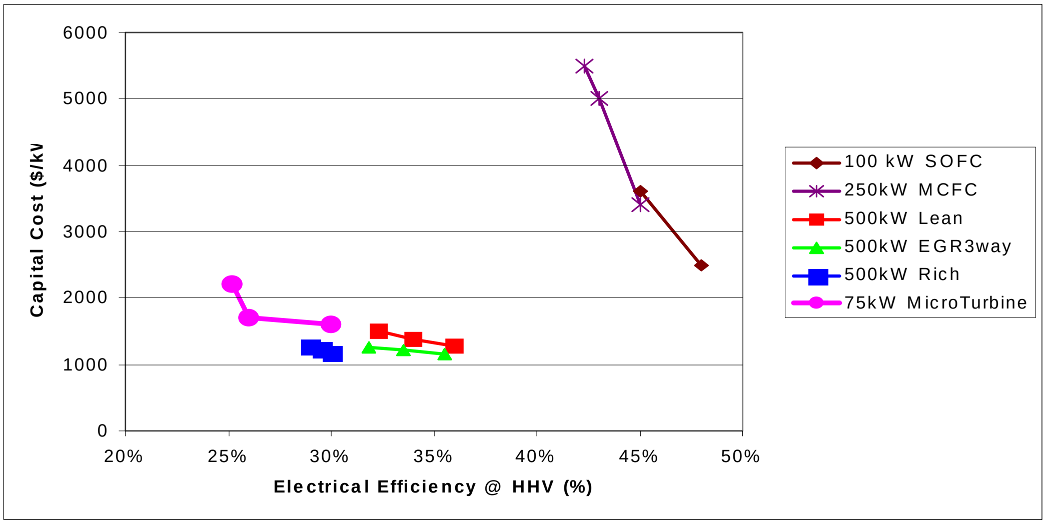
Figure 7 - Base Case Efficiency Projections (Selected > 1 MW Technologies)



Figures 8 and 9 below show the expected improvements in installed cost and efficiency expected to occur by 2007 and 2012 respectively. The point to the left end of each 3-

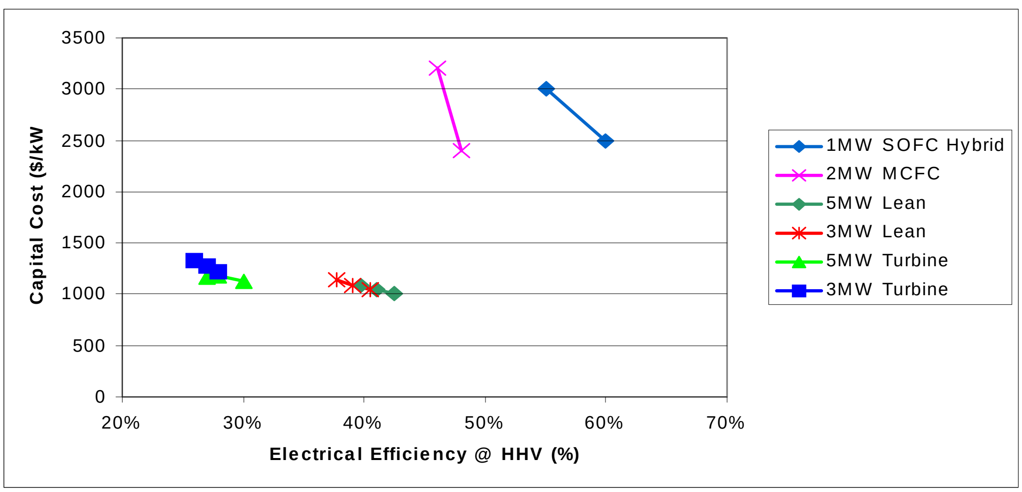
point data set is typical of today's conditions. The next two points are projections for 2007 and 2012. Two point sets are for technologies not commercially available today.

Figure 8 - Capital Cost and Efficiency Projections (Selected < 1 MW Technologies)



* Not currently commercially available

Figure 9 - Capital Cost and Efficiency Projections (Selected > 1 MW Technologies)



* Not currently commercially available

Technology Drivers

The potential for technology improvement is shaped by technology maturity, defined technology advancement paths, regulations and economic market size. Market robustness, available resources, regulations and size of the ultra-clean market will guide the pace of improvement. These factors were considered when developing the limited, base and accelerated scenarios. Specific technology drivers contributing to the pace of advancement are summarized below.

Gas Turbines - Advanced technology efforts focused on internal blade cooling and ceramic materials are expected to result in continuing improvements in efficiency (beginning with the largest sizes) along with gradual declines in capital and maintenance costs. Gas turbine emissions are among the lowest of commercially available DG technologies and will continue to decline as combustion technologies advance and are adapted to specific hardware configurations. Technology advances likely over the next ten-year period include:

- Increases in turbine inlet temperature and pressure ratio. In parallel, more advanced blade cooling techniques and DLE combustor modifications.
- More precise manufacturing tolerances.
- Lean-pre-mix DLE combustors reach single digit NOx (<10 ppm) levels in selected products
- Low-NOx pilots enable DLE combustors to approach 5 ppm for selected products
- Catalytic combustors applied to several gas turbine products
- Other advanced combustion concepts such as surface combustion become ready for commercial application
- Evolutionary cost refinements to SCR systems
- Low emission combustors for HRSG duct burners
- Improvements to high electric efficiency cycles such as recuperation and steam turbine bottoming (combined cycle) in the smaller sizes. Note that depending on the application, these cycles often increase electric efficiency at the expense of overall CHP efficiency.

Reciprocating Engines - Technology has improved dramatically over the past decade, and the steady pace of evolutionary improvements is expected to result in ongoing efficiency increases and gradually declining capital and maintenance costs. Emissions are the biggest challenge confronting reciprocating engines in environmentally sensitive markets. Both lean-burn and rich-burn engine technology will be strained to keep pace with the more stringent out-year emission requirements. EGR w/3-way catalyst is the approach that shows the best promise for keeping pace with ultra-clean requirements while maintaining the advantage of lean burn fuel efficiency.

Technology advancements likely to be commercially developed within the next 10 year period include:

- Variable valve timing (Miller cycle) features along with reduced internal friction for improved cycle efficiency
- Combustion and controls precision and higher energy ignition to push out lean limits, coupled with exhaust gas recirculation (EGR) for reduced emission formation
- Refined catalyst formulation, durability, and ultra-precision O_2 sensors and fuel/air ratio controls for rich burn and EGR engines
- SCR and oxidation catalyst formulation enhancements, package integration and shared controls for lean burn engines
- Higher efficiency turbochargers and air systems

- Advanced combustion concepts such as micro-pilot ignition, hydrogen augmentation, and homogeneous charged compression ignition (HCCI).

Microturbines – Technology priorities are to reduce equipment and installation costs, and to increase electric efficiencies. Although emission control challenges remain, they appear surmountable with refinements to conventional DLE techniques such as lean-pre-mix and rich-quench-lean approaches.

Technology advancement efforts include more precise manufacturing tolerances, higher firing temperatures and tolerant hot section parts, higher effectiveness recuperator, and lower cost manufacturing techniques. Many of these performance goals create additional challenges on achieving emissions and equipment cost targets. Technology progress to be expected over the next ten years include:

- Selected higher temperature metallic components
- Higher effectiveness recuperators
- Ultra-low emission combustor designs
- More efficient compressors and turbine sections and optimized cycle
- Larger (200 – 300 kW) product sizes
- Selected ceramic components in the 200 kW class machines

Fuel Cells – The most important technology improvements for fuel cells are fuel cell stack cost and life, and reformer cost. The major areas with potential for cost reduction and advancement are:

- Engineering simplifications and manufacturing techniques
- Commoditization of components within the system, such as the membrane electrode assembly (MEA) in PEM fuel cells, power conditioning and controllers, heat transfer and condensing units, and the fuel processing or reformer.
- Overall system simplification, eliminating parts and components.
- Technical limitations of conductive plastic, injection-molded interconnect plates for PEM stacks are overcome; or low-cost, metal fine film technologies mature decreasing production costs.
- High temperature PEM systems are developed that increase stack tolerance to carbon monoxide concentrations, and allowing fuel processing subsystem simplifications and cost reductions.
- Materials properties for MCFC stack components are achieved eliminating risk of short stack life cycles.
- Integrated high-temperature fuel cell and gas turbine systems validate process models and achieve enhanced electrical efficiency capabilities.

Notes

No costs were included for Continuous Emission Monitoring (CEM) or for measurement and verification of efficiency levels. Should these be required and depending on the protocols required, this could be a significant expense that endangers the whole CHP value proposition, hurting smaller systems the hardest.

Economic Implications

Net electricity costs of CHP were calculated for each of the technologies, timeframes and scenarios profiled. The intent of this analysis is to illustrate the relative economic value of the technology medley. The costs were then overlaid on State average commercial and industrial energy prices to get a sense for economic market potential and impacts associated with a number of variables. The variables considered included inter-technology competition, gas price and heat utilization sensitivity, incremental cost of after-treatment, and the pace of technology advancement.

The net cost of electricity, in $/kWh, is estimated as the annual sum of five main components, divided by the total annual output of the generator:

- Annual Capital Cost - The annual capital cost is equal to the annual capital carrying charges, in the form of an annuity, divided by the total amount of electricity generated. This calculation incorporates the unit capital cost of the equipment, an assumed lease term and interest rate, and a capacity factor for the generator. The capacity factor is an estimate of the annual utilization of full load generating capacity.

- Net Fuel Cost - The net fuel cost is equal to the difference between the cost of the natural gas consumed by the generator and the cost of the boiler fuel avoided in utilizing recovered heat in the CHP application. This calculation requires certain assumptions regarding: natural gas price; generator electric and thermal efficiencies; efficiency of the boiler whose output is displaced by the recovered heat; and a thermal utilization factor, which is the percentage of the total recoverable heat that is utilized in the CHP application.

- O&M Cost - The O&M cost includes all of the non-fuel annual operations and maintenance costs.

- After-treatment (AT) Annual Capital Cost - The AT annual capital cost is the cost of any installed after-treatment equipment, calculated in the same way as the generator capital cost.

- AT O&M cost - The AT O&M cost is the annual operations and maintenance cost of the after-treatment equipment, if any.

Tables 1 and 2 summarize the assumptions made in calculating the net cost of electricity. Interest rate, lease term and boiler efficiency are all assumed to be the same for all systems. The load factor (% full load operating hours) and thermal utilization factor (% recovered heat uttilized) are assumed to be higher, and the gas price is assumed to be lower, for larger systems.

Table 1 – Assumptions for All Systems

Parameter	Units	Value
Interest Rate	%	8%
Lease Term	yrs	10
Boiler Efficiency	% HHV	80%

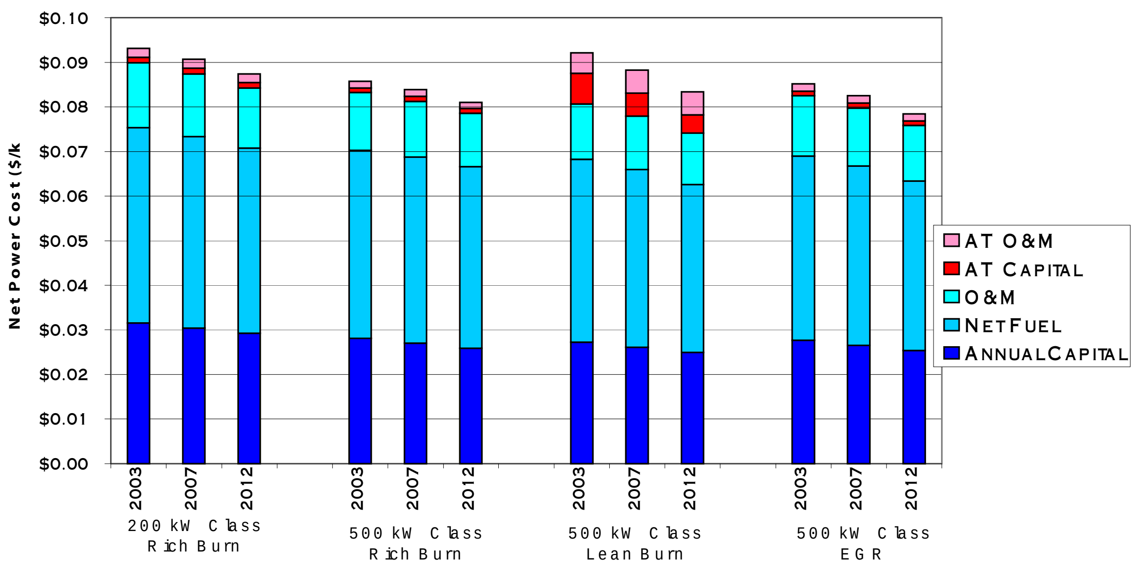
Table 2 - Assumptions by System Size

Assumptions by System Size	Gas Price $/MMBtu	CHP Load Factor[2]	Thermal Utilization Factor
< 500 kW	$6.00	75%	75%[3]
500-1000 kW	$5.00	75%	75%
1 - 3 MW	$5.00	85%	75%
>3 MW	$5.00	85%	80%

CHP Economic Findings

Figures 10 and 11 show the net power costs based on the technology profiles described in the previous section for several reciprocating engine technologies, in the base case, for 2003, 2007 and 2012. Note that SCR can add upwards of 15% to the net cost of power from lean burn engine CHP systems. For the sizes considered, EGR engines exhibit the best economics due to efficiency advantages over rich burn and to after-treatment cost advantages over lean burn engines. EGR engines show promise to become the best economic and technical solution for reciprocating engines in emission-constrained areas.

Figure 10 - Small Reciprocating Engine Net Power Costs -- Base Case



2 Annual full load hours divided by 8760 hours

3 Except for PEM and PAFC fuel cells, whose heat utilization factors were estimated at 65%

Figure 11 - Large Reciprocating Engine Technology Net Power Costs -- Base Case

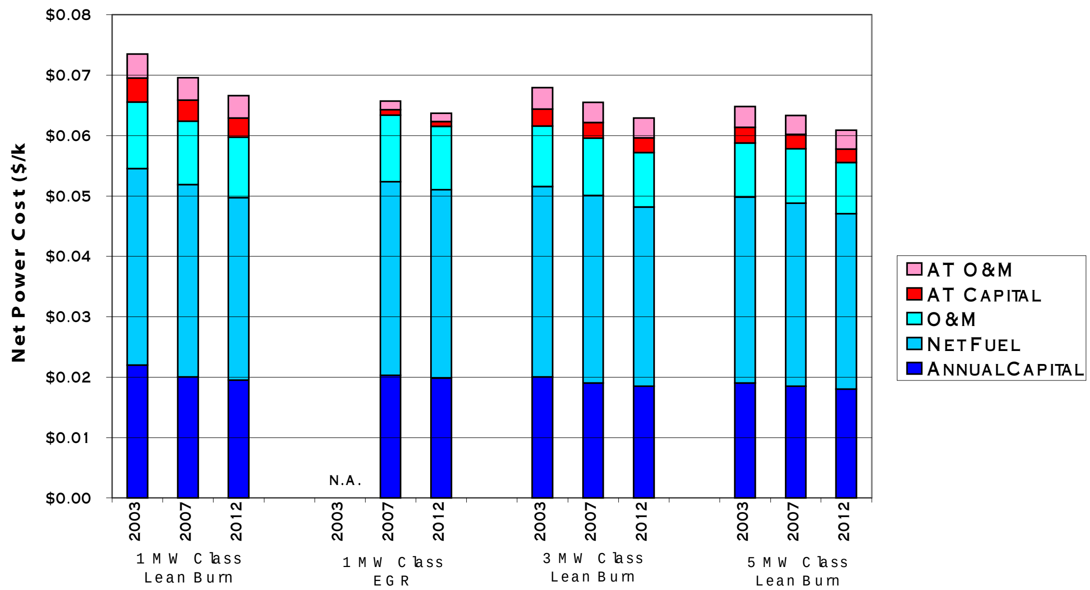


Figure 12 shows the net power costs for two microturbine sizes in the base case. As shown, although some economic betterment is projected over time, microturbines are not expected to do better than reciprocating engines over time. Microturbines should have an emission edge over rich burn and lean burn engine systems but not EGR engine systems.

Figure 12 - Microturbine Technology Net Power Costs -- Base Case

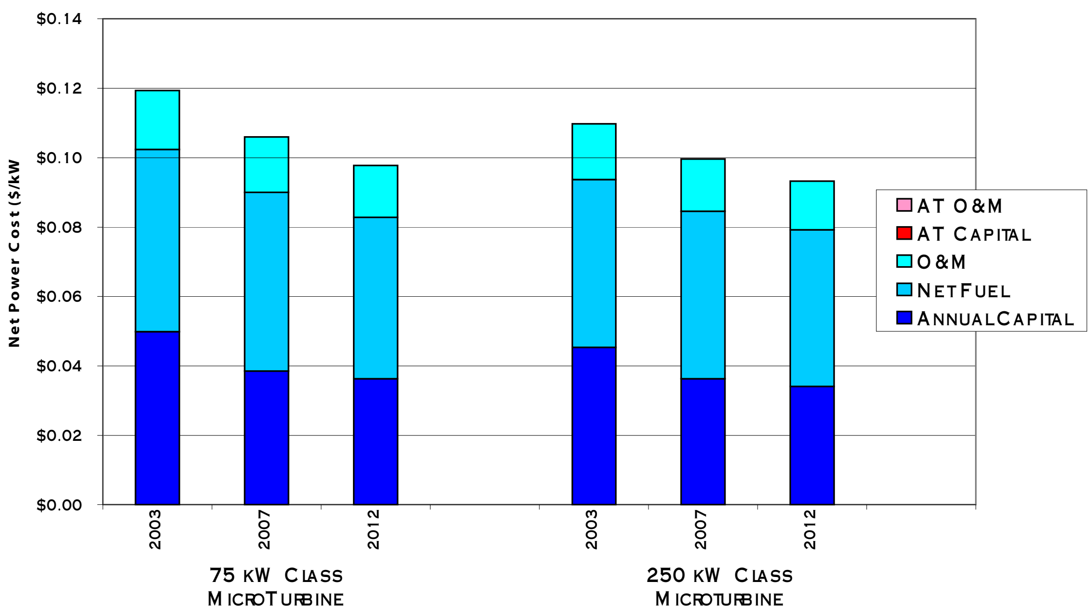


Figure 13 shows the net power costs for five different industrial gas turbine technologies, ranging in size from 3 MW to 10 MW. Note that with good heat utilization, turbine systems as with the larger recips can deliver power in the $0.06/kWh range. As with lean burn recips, turbines are handicapped by SCR attributing in the vicinity of 10% to net power costs. Catalytic combustors also increase power costs but not to the degree SCR does.

Figure 13 - Gas Turbine Technology Net Power Costs -- Base Case

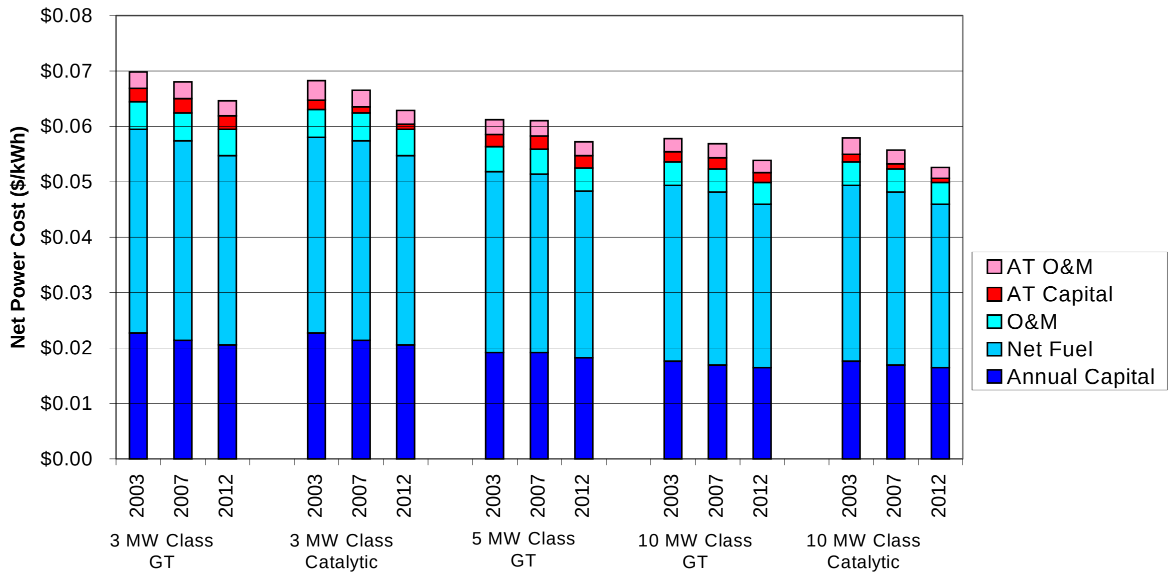
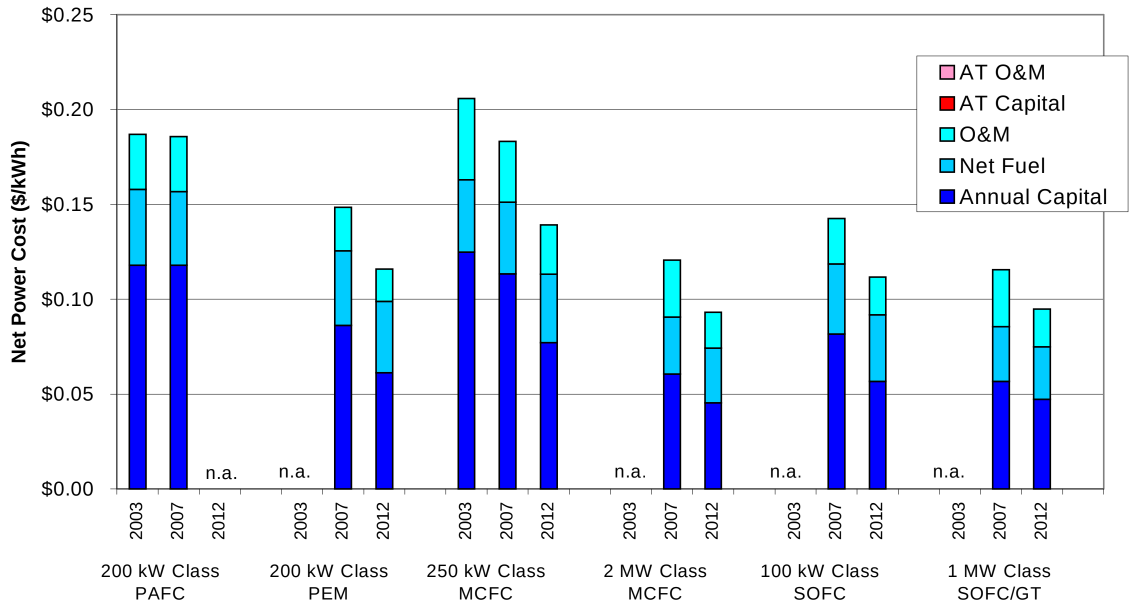


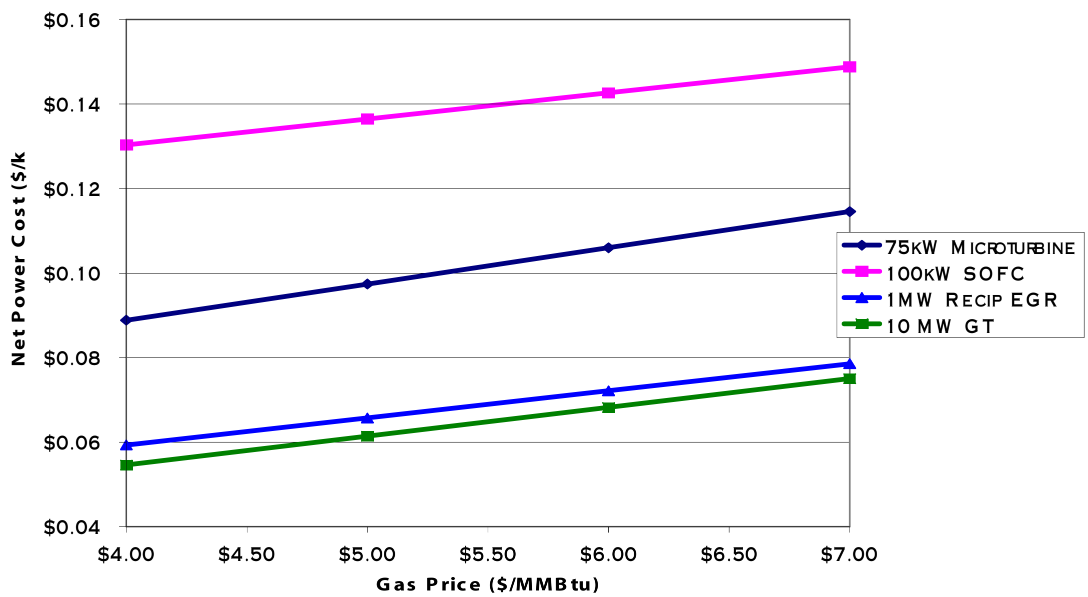
Figure 14 shows the net power costs for six different fuel cell technologies, ranging in size from the 200 kW PAFC and PEM technologies to the 2 MW MCFC, and including the 1 MW SOFC / gas turbine hybrid system. The PEM, SOFC and the larger MCFC are still in pre-commercial stages of development so no analysis is included for them for 2004. Substantial price reductions are foreseen for the PEM, SOFC and SOFC hybrid units with market maturity and technology advancements.

Figure 14 - Fuel Cell Technology Net Power Costs -- Base Case



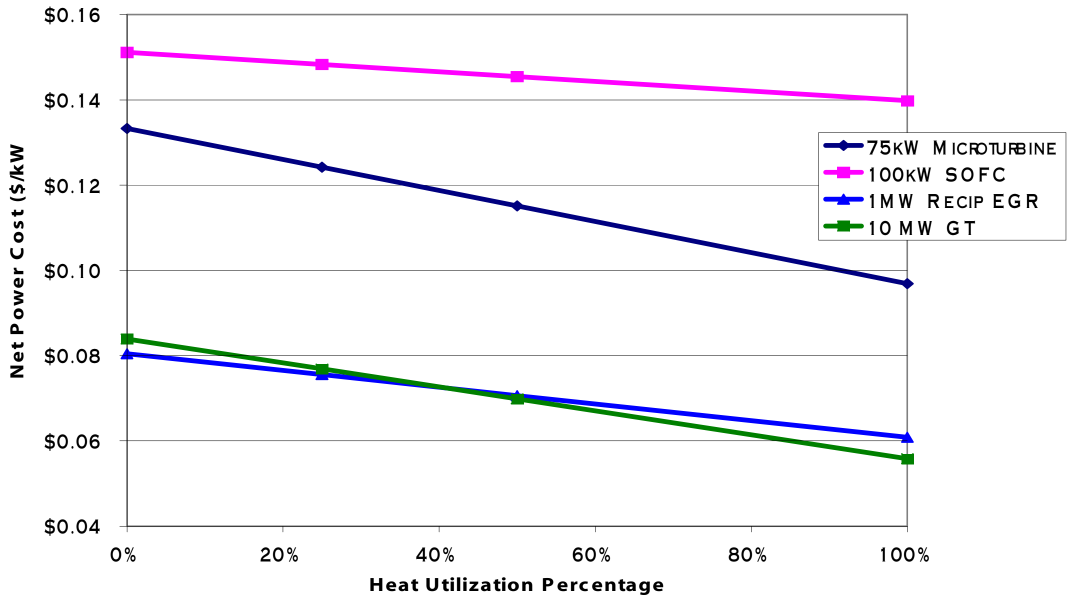
For selected technologies, Figure 15 illustrates the net cost sensitivity to gas prices. As the value of recovered heat is linked to gas prices, the impact on net CHP electric costs is mitigated.

Figure 15 - Selected Technologies -- Base 2007 Gas Price Sensitivity



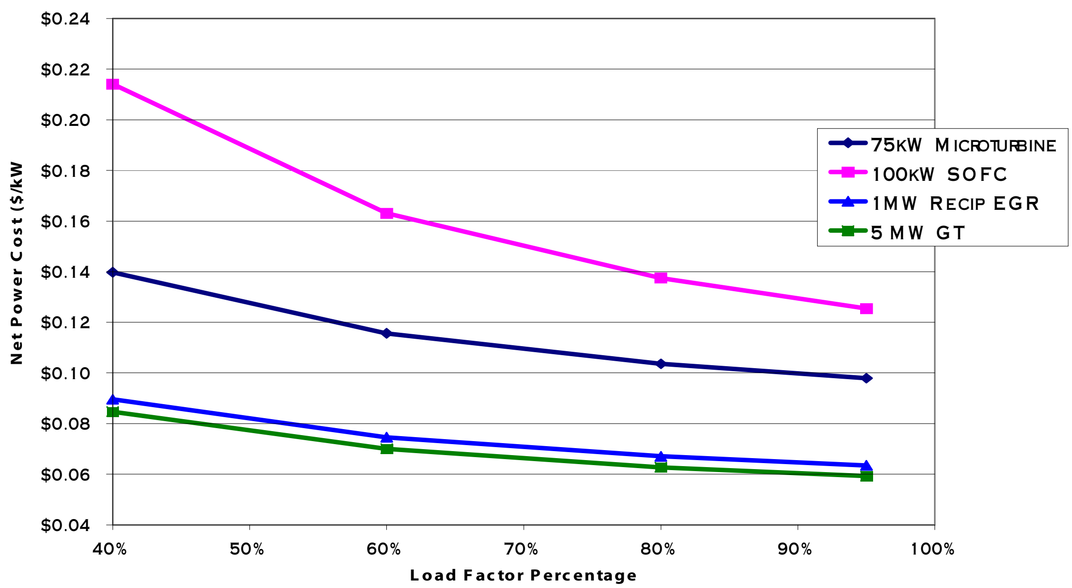
Likewise, Figure 16 shows the sensitivity to heat utilization efficiency. As expected the sensitivity is greatest for technologies with lower electric efficiencies.

Figure 16 - Selected Technologies -- Base 2007 Heat Utilization Sensitivity



The sensitivity of capacity utilization or load factor to CHP power cost is illustrated in Figure 17, with the more expensive CHP systems exhibiting the greatest sensitivity to economics.

Figure 17 - Selected Technologies -- Base 2007 Load Factor Sensitivity



Figures 18 and 19 point out the impacts of limited and accelerated technology cases relative to the base case for selected technologies, with the less mature technologies having the biggest divergence between scenarios.

Figure 18 - Scenario Comparisons of Net Power Costs -- Selected 1 MW Class

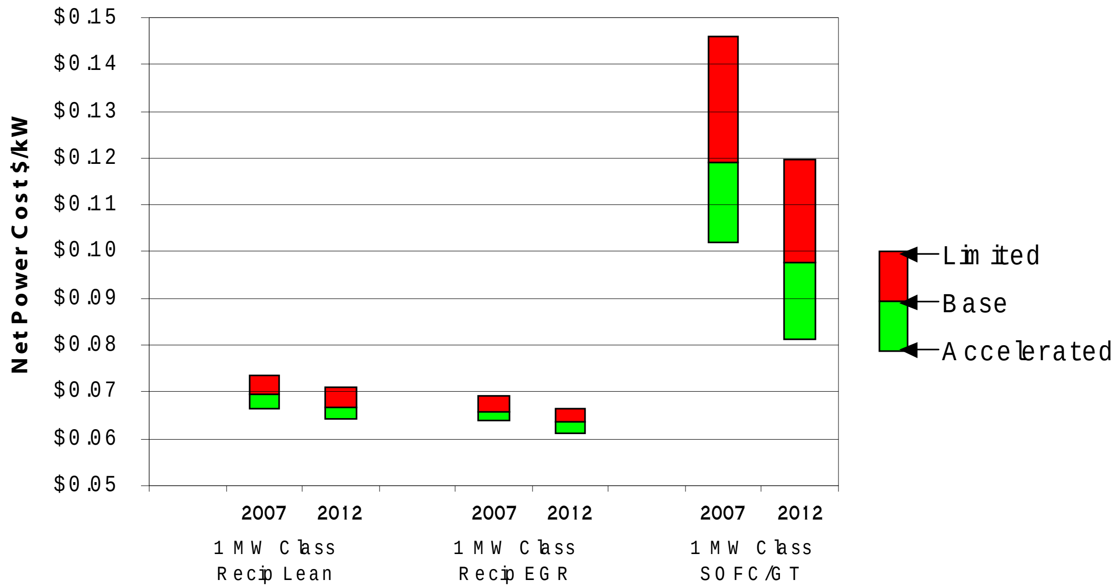
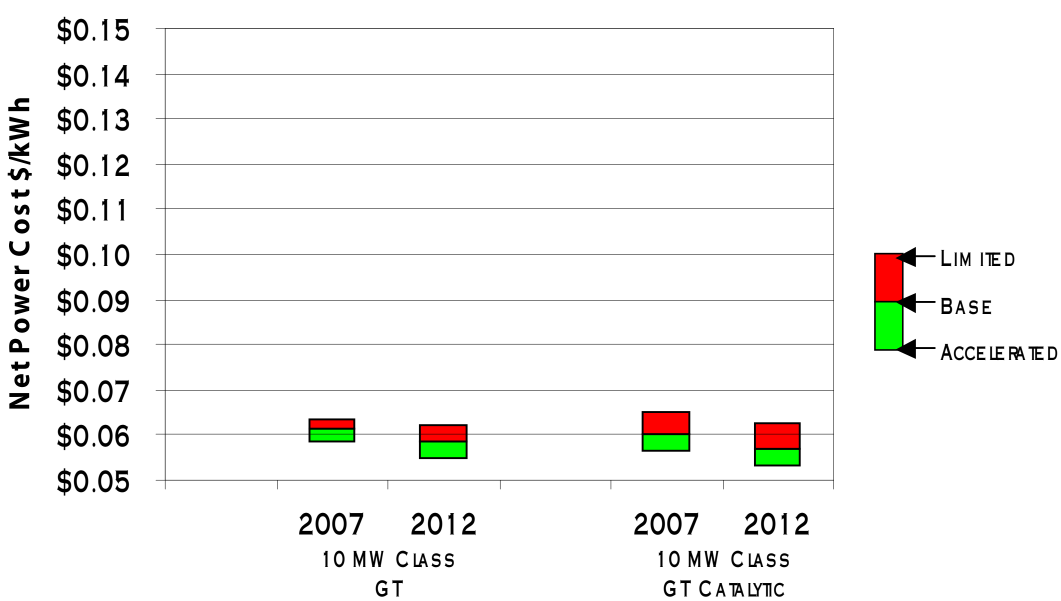


Figure 19 - Scenario Comparisons of Net Power Costs -- Selected 10 MW Class Technologies



Market Sensitivity

The estimated net cost of self-generated electricity has been compared to the national distribution of retail power costs, as published by the Department of Energy's Energy Information Administration to approximate the U.S. market share where CHP economics beats average retail prices.

To estimate the competitive market share of any given technology scenario the net cost of electricity in that scenario is compared to the national distribution of retail power costs. Figure 20 shows commercial and industrial electric prices for the year 2002, displayed as the percentage of the U.S. market that is at or above a given price.

Figure 20 - Average Electric Rate by Market Share[4]

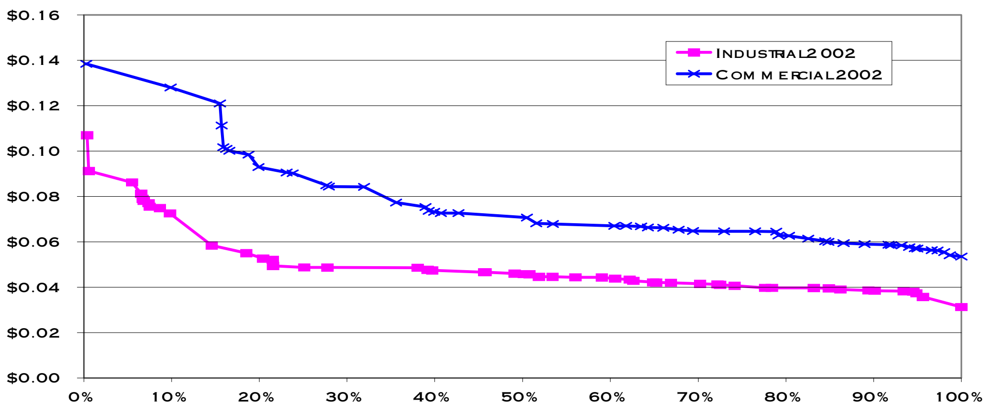
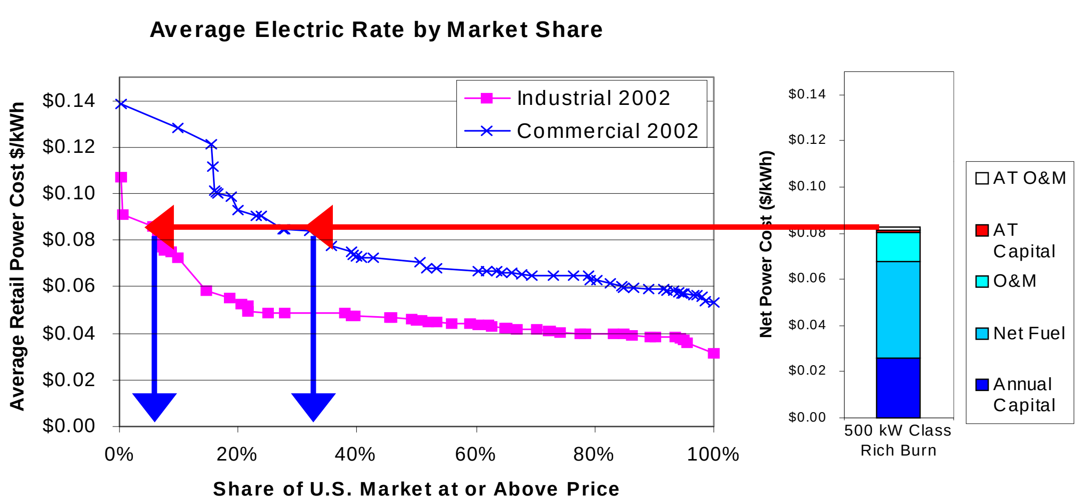


Figure 21 shows how net power costs can be compared to the prices in Figure 20 to estimate the economic market share. The intersection of the CHP net electric cost with the commercial and industrial price curves identifies the share of electricity sales in the U.S. that are more expensive than the CHP option. For purposes of this analysis, we assumed that technologies < 1 MW in size would best compare against commercial prices and technologies 1 MW and larger would best measure up to industrial prices.

Figure 21 - Estimating Competitive Market Share



Figures 22 and 23 represent how base case small reciprocating engine power costs and microturbine power costs translate to commercial sector economic market share potential (i.e. the percentage of the U.S. commercial electricity sales that are more costly than the various CHP scenarios). The economic share increases over time are greater for many of the reciprocating engine technologies relative to the corresponding cost of power improvements because the net cost of generated electricity falls on a fairly flat region of the retail cost / market share curve (see Figure 21).

Figure 22 - Small Reciprocating Engine Technology Economic Market Share

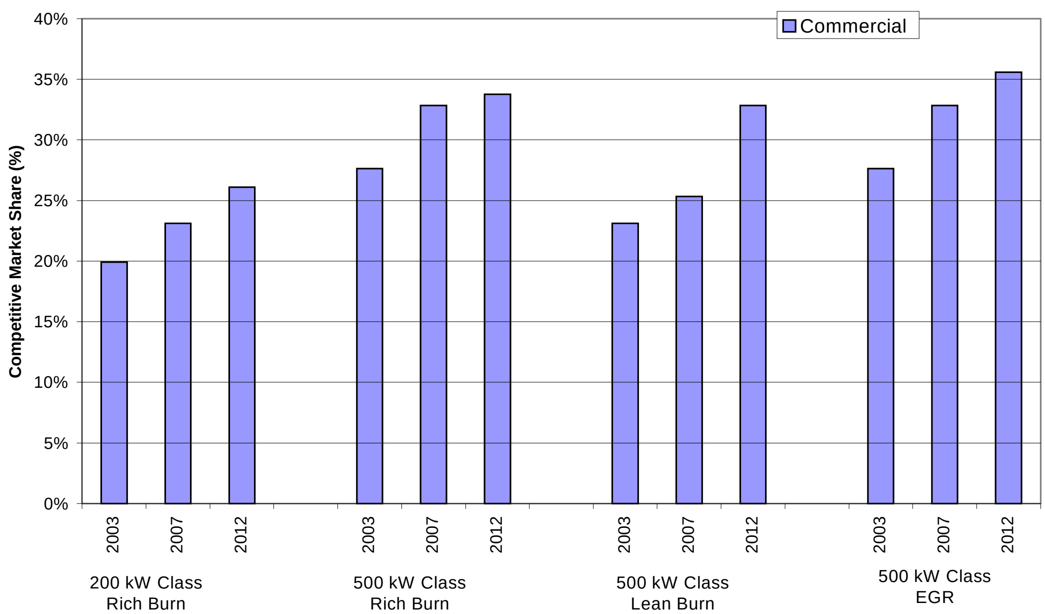
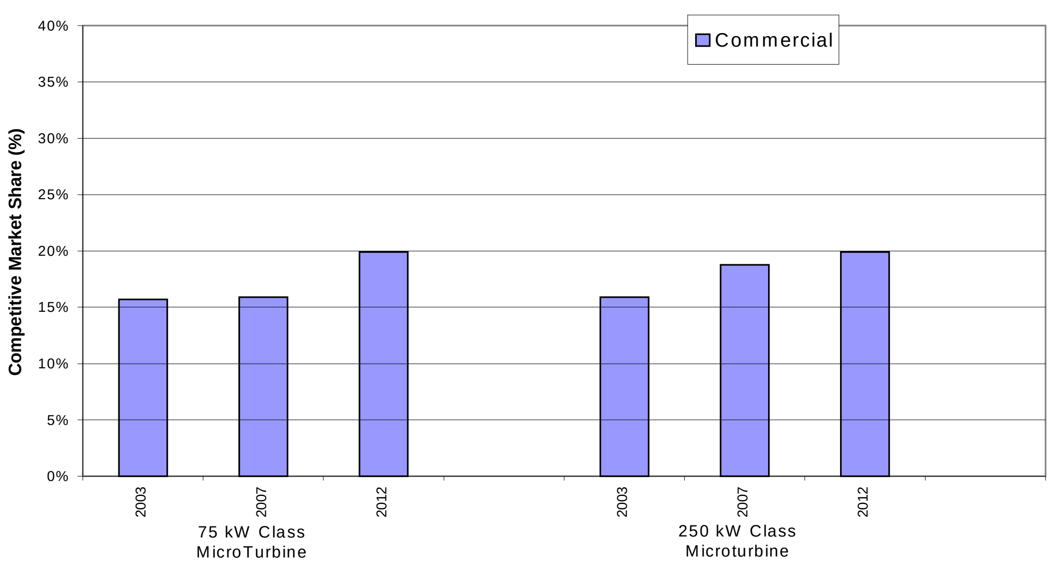


Figure 23 - Microturbine Technology Economic Market Share



Figures 24 and 25 characterize the industrial economic market share changes over time for large reciprocating engines and for industrial turbines respectively. Market share levels for these larger technologies are somewhat lower than for the smaller CHP systems due to lower electricity prices to industrial users. Of note is the generally more favorable market share position for industrial turbines with catalytic combustors than for those with SCR.

Figure 24- Large Reciprocating Engine Technology Economic Market Share

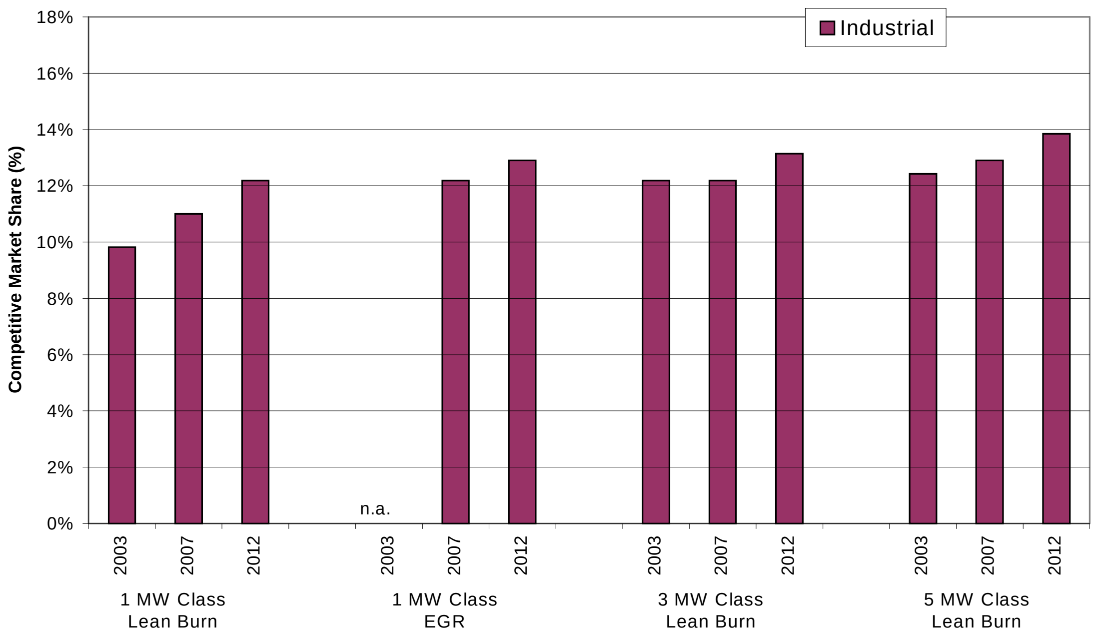
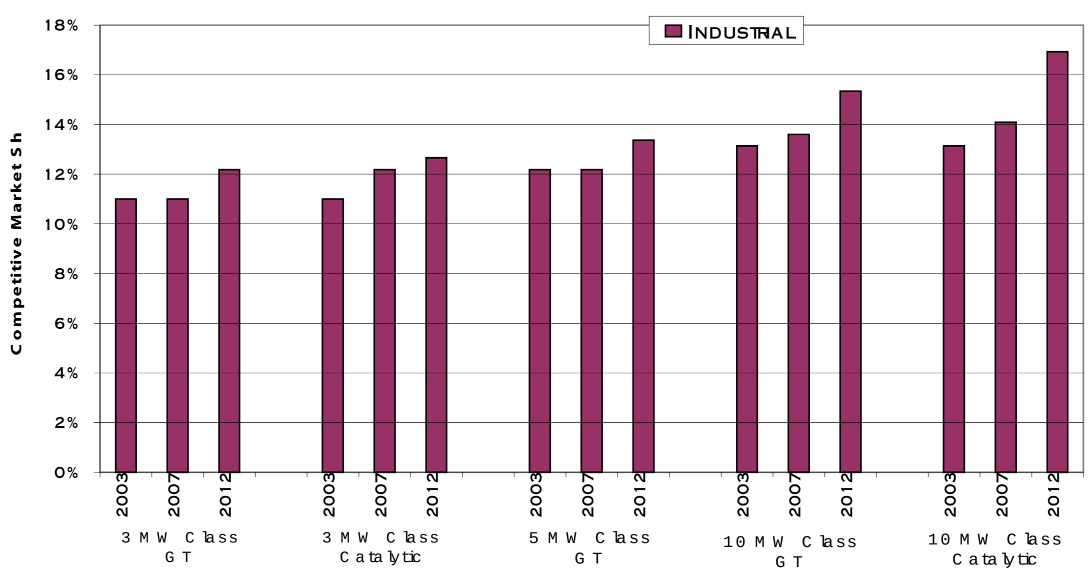


Figure 25 - Gas Turbine Technology Economic Market Share



The economic market impact of after-treatment for selected engines and turbines are shown in Figures 26 and 27 for the base case 2007. As indicated, the economic impact is greatest for technologies burdened with SCR. For lean burn engines in the 500 kW size class, SCR reduces economic market share by 30%. And for gas turbines in the 3 MW to 5 MW size range, SCR decreases economic market share by 10 - 12%.

Figure 26 - Market Comparison for Selected Engines -- With and Without Aftertreatment Costs - 2007 Base Case

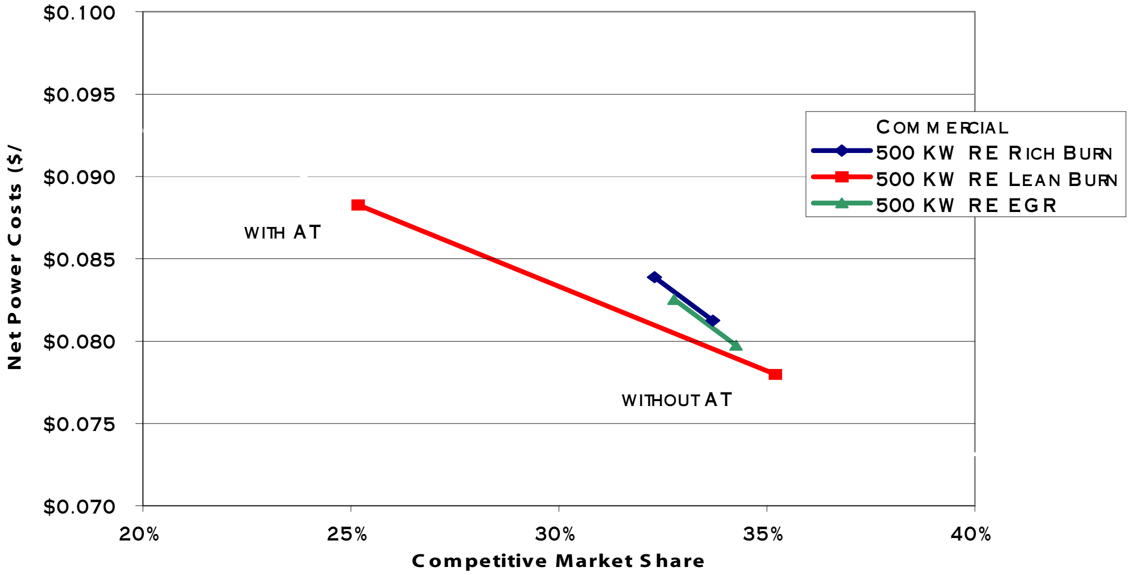
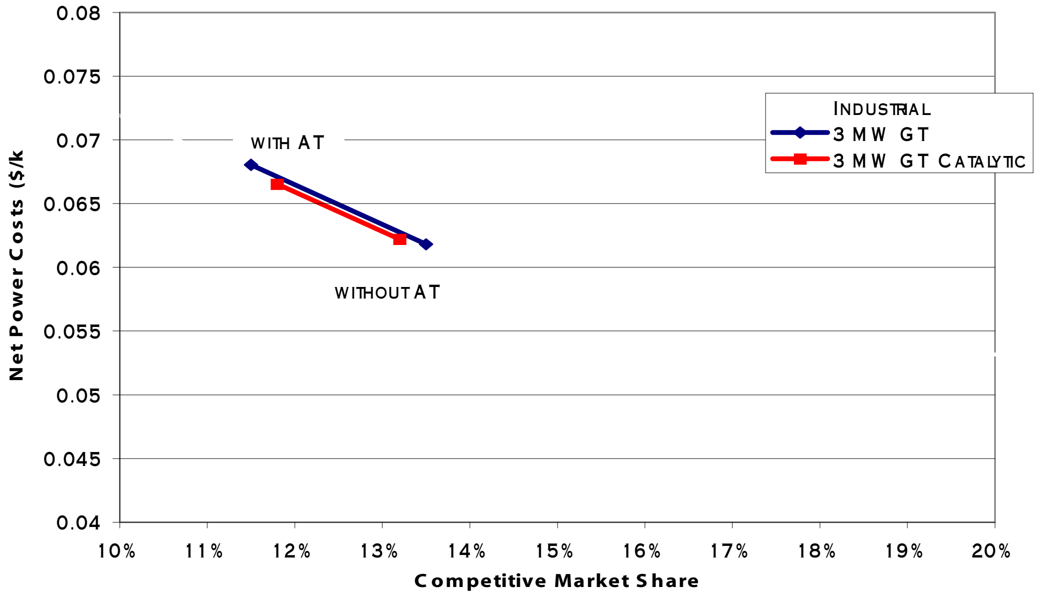


Figure 27 - Market Share for 3 MW Class GT -- With and Without Aftertreatment Costs - 2007 Base Case



Regulatory Assessment

Many states are beginning to focus on emissions regulations relating to distributed generation, and the regulatory model varies from state to state. Here we examine three different models, all of which are "output based", encouraging system efficiency by awarding emissions credit for combined heat and power.

Overview of Regulatory Models

CARB

In October of 2002 the California Air Resources Board (CARB) established a DG certification program and guidelines for the emissions of NOx, CO, VOCs and particulate matter. The CARB rule set levels for these pollutants that had to be attained by January 1, 2003 and a stricter set of levels for Jan 1, 2007. Table 3 shows the NOx, CO and VOC CARB emissions standards for 2003 and 2007.

Table 3 - CARB Emissions Standards (lb/MWh)

Pollutant	DG Unit without CHP (2003)	DG Unit with CHP (2003)	DG Unit with CHP (2007)
NOx	0.5	0.7	0.07
CO	6.0	6.0	0.10
VOC	1.0	1.0	0.02

The 2007 DG guidance levels allow a heat recovery credit for qualifying CHP of one MWh for each 3.4 million Btu of recovered heat.

RAP

Under a contract with the National Renewable Energy Laboratory (NREL), the Regulatory Assistance Project (RAP) convened a working group of state utility regulators, state air pollution regulators, representatives of the distributed resources industry, environmental advocates, and federal officials. This group developed a model emissions rule for DG and published a draft of the rule in 2002. Several northeastern states are using the RAP model as a basis for developing their own rules. The RAP model is similar to the CARB rule in that it establishes standards for NOx, CO and PM. Unlike the CARB rule, it also addresses CO_2 but does not address VOC. The pollutant levels in the RAP model are established in three phases – January 1, 2004; January 1, 2008; and January 1, 2012. Table 4 shows the NOx, CO and CO_2 RAP emissions standards for the three phases.

Table 4 - RAP Emissions Standards (lb/MWh)

Pollutant	Phase One (2004)	Phase Two (2008)	Phase Three (2012)
NOx	0.6	0.3	0.15
CO	10	2	1
CO_2	1,900	1,900	1,650

The RAP model also gives credit for recovered heat in a combined heat in power installation, but in a different way than the CARB rule does. In the RAP model the emissions credit allowed is equivalent to the amount of a given pollutant that would have been created by a conventional separate system (*e.g*., boiler) used to generate the same thermal output. A boiler efficiency of 80% is assumed and, for CHP facilities that replace existing thermal systems for which historic rates can be documented, the historic emission rates are used; but not more than: 0.3 lb/MMBtu for NOx, 0.08 lb/MMBtu for CO and 117 lb/MMBtu for CO_2. In this analysis we used Connecticut's new boiler standard for NOx (0.2 lb/MMBtu) as Connecticut is farthest along with a draft DG regulation patterned after the RAP rule.

<u>East Texas</u>

In May of 2001 the Texas Natural Resources and Conservation Commission (TNRCC) issued a Standard Permit for Small Electric Generators. This standard sets NOx limits of 0.47 lb/MWh for units installed before January 1, 2005, and 0.14 lb/MWh for units installed after January 1, 2005 in non-attainment areas in East Texas. The Texas standard does not address any pollutants other than NOx. As in California, a CHP credit is allowed at a rate of 1 MWh for each 3.4 MMBtu of recovered heat.

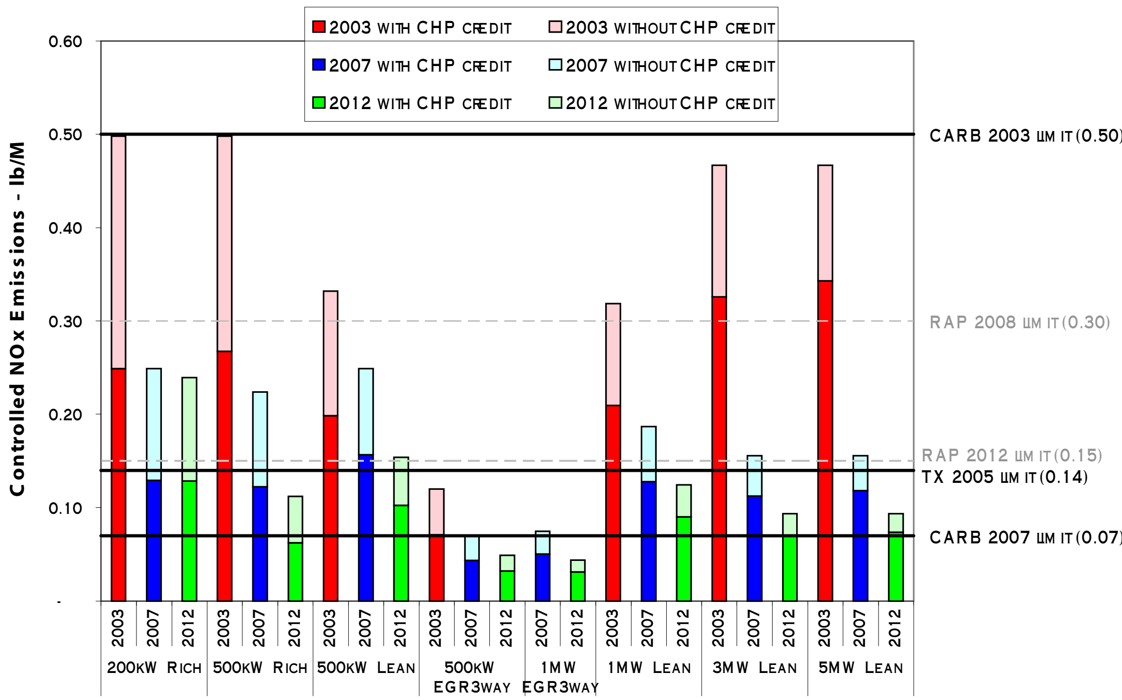
Effect of Regulatory Models on Emission Levels

For the economic analysis, "typical" heat recovery and utilization values were used that are above the minimum eligibility thresholds for the heat recovery credit. For this section, in order to be somewhat conservative with the value of the heat recovery credit and in establishing allowable prime-mover system emission levels for CHP applications, we reset (lowered) the heat recovery levels to just meet the thresholds. RAP and California were reasonably consistent in the establishment of a CHP threshold – overall system efficiency of 60% LHV in California and 55% HHV in the RAP model rule. The analysis in this section recalibrated all technology profiles to 60% LHV overall efficiency for the California and East Texas assessment and to 55% HHV for the RAP overlay.

<u>NOx</u>

Figures 28 through 30 show electric-only and CHP NOx emissions in California and Texas for the reciprocating engine, turbine and fuel cell technologies. In all cases, the "base" scenario for 2007 and 2012 is shown on the charts. The top bars represent the "electric-only" emissions out of the CHP system without any credit provided for heat recovery. The bottom bars represent emission levels with credit given for heat recovery using the CARB and Texas method for calculating the heat recovery credit. The dark lines correspond to the CARB and TNRCC levels. The lighter lines represent the RAP model levels, but as RAP uses a different heat recovery credit method, these levels do not apply to the lower bars

Figure 28 - NOx Emissions for Reciprocating Engines, CARB and TNRCC

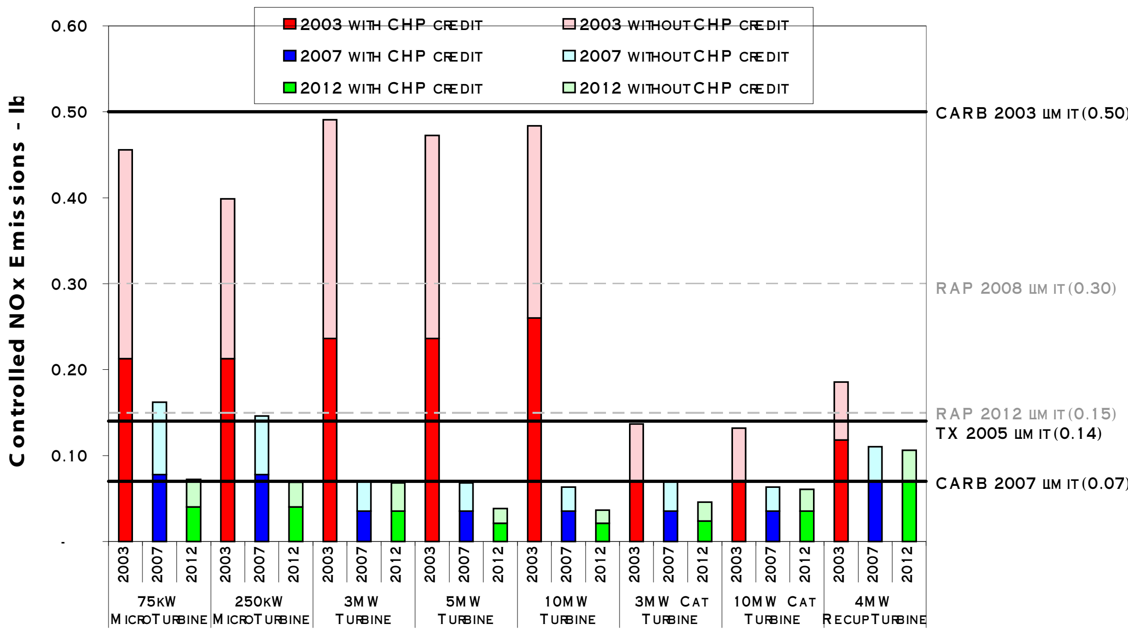


As shown in Figure 28, all of the reciprocating engine technologies, with aftertreatment, are meeting the current CARB levels, even without the CHP credit. The rich burn engines, with three-way catalyst, should meet the East Texas limit by 2007 with the CHP credit. However they will probably not meet the CARB 2007 limit, except for the 500 kW rich burn engine which looks to meet that limit by 2012. Even in the accelerated case (not shown on the chart) the 200 kW rich burn engine will not meet the CARB 2007 standard until 2012.

As with the rich burn engines, the lean burn engines with SCR and CHP credit will meet the East Texas 2005 limit by 2007 with the sole exception of the 500 kW size. This engine will meet the East Texas limit by 2012. None of the lean burn engines will meet the CARB standard by 2012, except for the large engines which are right at the limit of 0.07 lb/MWh with the CHP credit. The 1, 3, and 5 MW lean burn engines would meet the CARB 2007 limits by 2012 in the accelerated case with heat recovery credit (not illustrated).

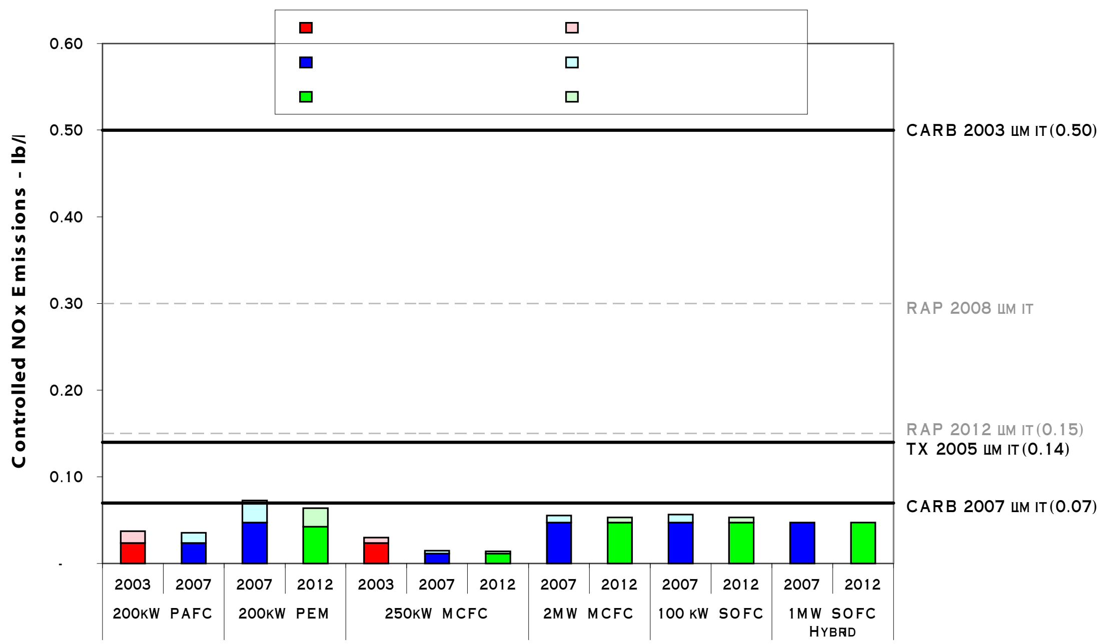
The reciprocating engines with exhaust gas recirculation and three way catalysts show good potential to meet both East Texas 2005 limits and CARB 2007 limits in CHP applications.

Figure 29 - NOx Emissions for Microturbines and Gas Turbines, CARB and TNRCC



All of the microturbine and gas turbine technologies are meeting the current CARB limits for CO. In the base case, microturbines will grapple to meet CARB by 2007 in CHP applications. In the accelerated case microturbines comfortably meet the CARB 2007 limits with the CHP credit. All of the gas turbine technologies will meet the CARB 2007 limit by 2007.

Figure 30 - NOx Emissions for Fuel Cells, CARB and TNRCC



All of the fuel cell technologies meet the impending East Texas and CARB regulations with no after treatment.

Figures 31 through 33 show electric-only and CHP NOx emissions for the reciprocating engine, turbine and fuel cell technologies using the RAP method for calculating the CHP credit. In all cases, the "base" scenario was used for 2007 and 2012. The RAP NOx standards are quite a bit more lenient than the CARB standards, and the RAP limit of 0.15 lb/MWh for 2012 is slightly higher than the East Texas limit for 2005. All of the technologies examined here meet the current RAP limit of 0.6 lb/MWh even without allowing for the CHP credit. Allowing the CHP credit, all of the technologies, with the exception of the 5 MW lean burn engine with SCR, currently meet the 2008 RAP limit as well. By 2007 all of the technologies should meet the 2012 RAP limit once the CHP credit is included.

Figure 31 - NOx Emissions for Reciprocating Engines, RAP

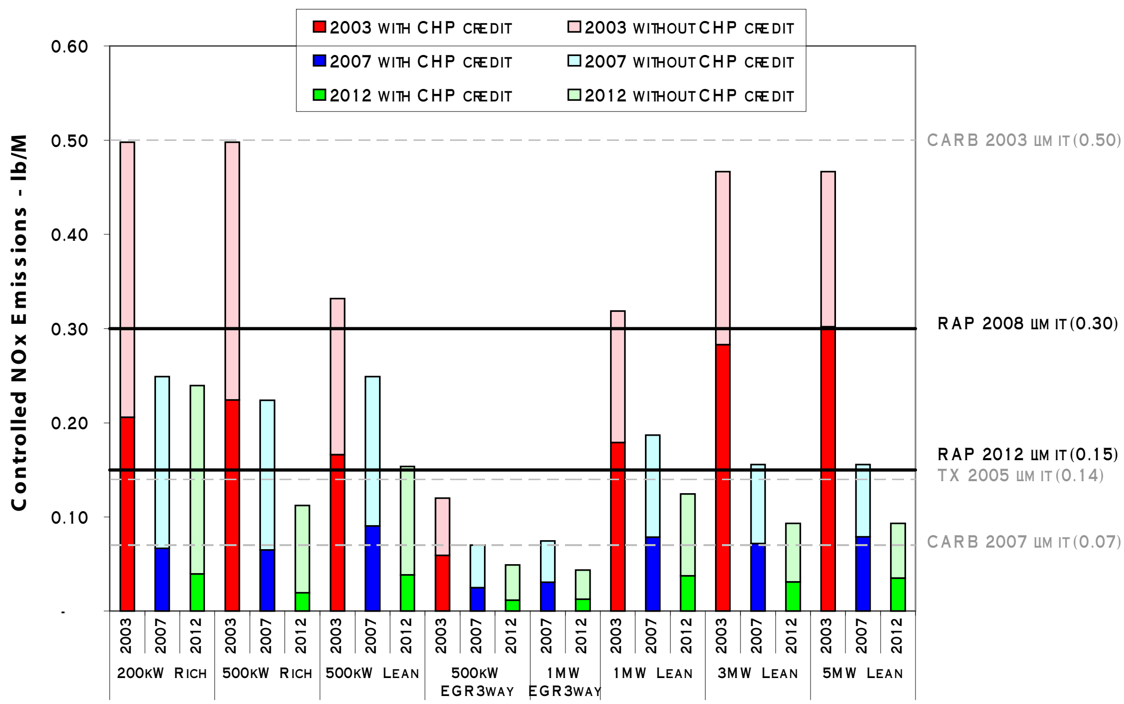


Figure 32 - NOx Emissions for Microturbines and Gas Turbines, RAP

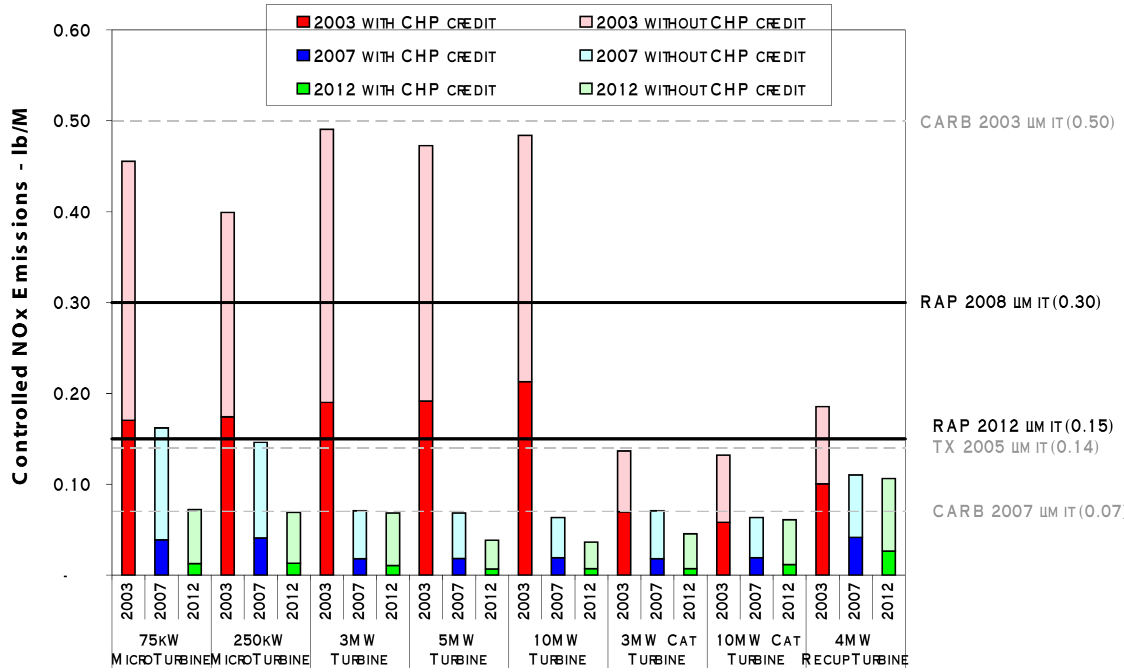
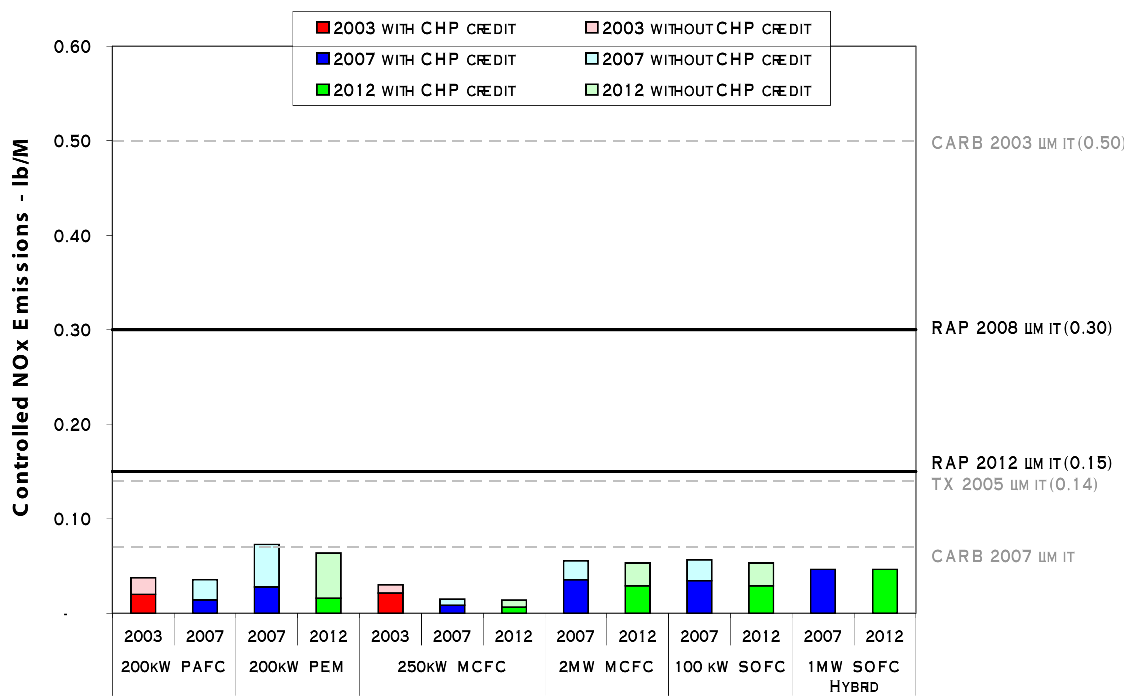


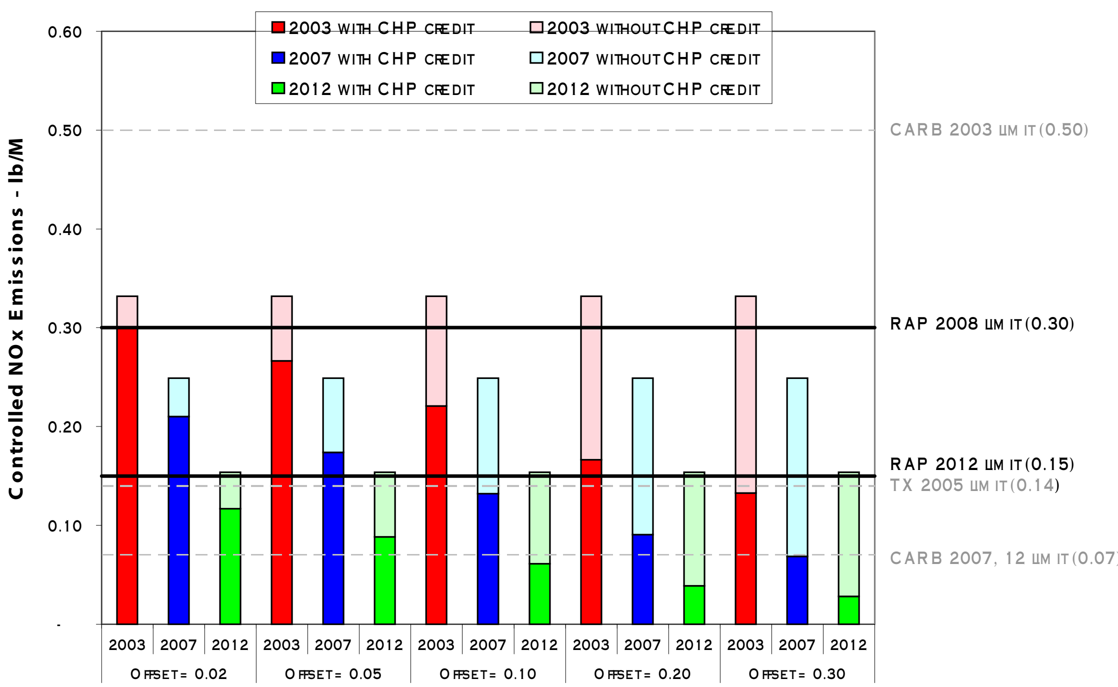
Figure 33 - NOx Emissions for Fuel Cells, RAP



As mentioned earlier, Connecticut's new boiler standard for NOx (0.2 lb/MMBtu) was used for the offset allowance in calculating the CHP credit for the RAP scenarios, instead of the maximum allowable value of 0.3 lb/MMBtu. In most cases this still results in a larger CHP credit than the CARB and TNRCC method of awarding a MWe credit equal to the value of the recovered heat would yield. Using the 500 kW lean burn engine as an example, Figure 34 illustrates the sensitivity of the CHP credit to the value used for the boiler offset.

If the boiler offset were raised, for example, from 0.2 lb/MMBtu to 0.3 lb/MMBtu the allowed credit would increase by 20% in 2003, 15% in 2007, and 10% in 2012. If the boiler offset were lowered to 0.1 lb/MMBtu the allowed credit would decrease by 33% in 2003, 26% in 2007, and 20% in 2012. Based on assumed improvements in engine design and after treatment technologies the percentage of actual NOx emissions that the credit would offset increases from 50% in 2003 to 75% in 2012 in the case where the allowance is 0.2 lb/MMBtu. If an allowance of 0.3 lb/MMbtu is used, the credit in 2012 would be equivalent to 82% of the actual emissions.

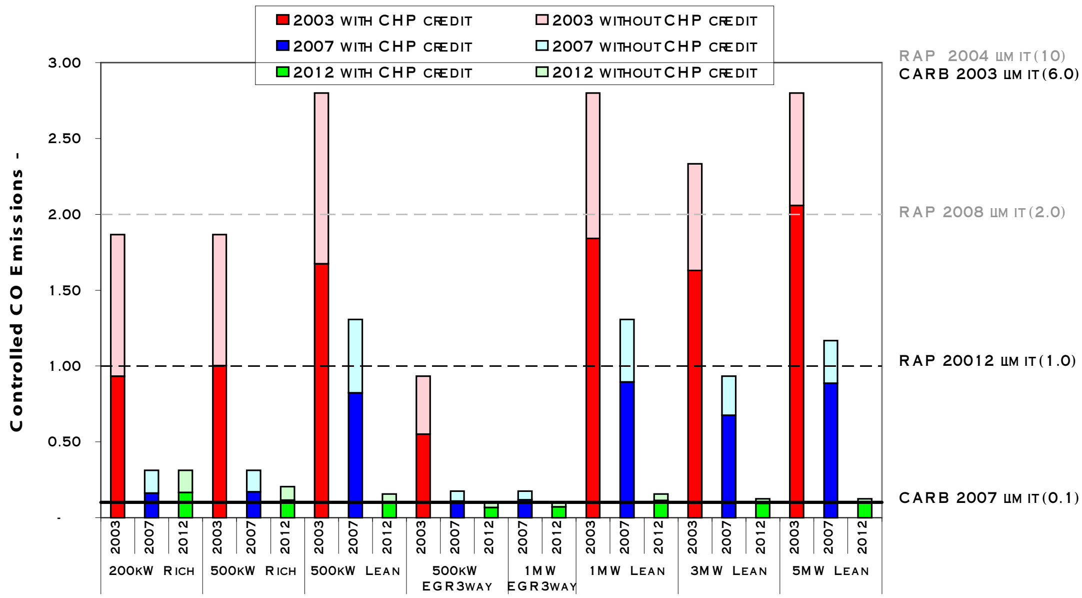
Figure 34 – Sensitivity of RAP CHP Credit to Boiler Offset Allowance (lb/MMBTU) - 500 kW Lean Burn Engine



<u>Carbon Monoxide</u>

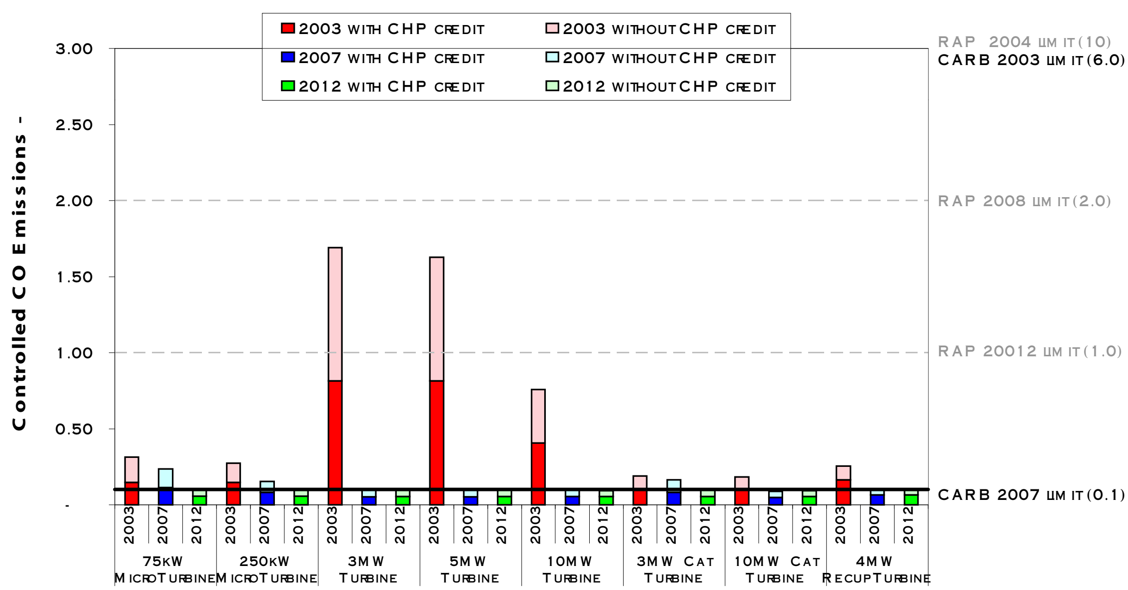
Figures 35 through 37 show CO emissions in California for the reciprocating engine, turbine and fuel cell technologies. In all cases, the "base" scenario was used for 2007 and 2012. Texas, at this time, does not regulate CO emissions for DG technologies.

Figure 35 - CO Emissions for Reciprocating Engines, CARB



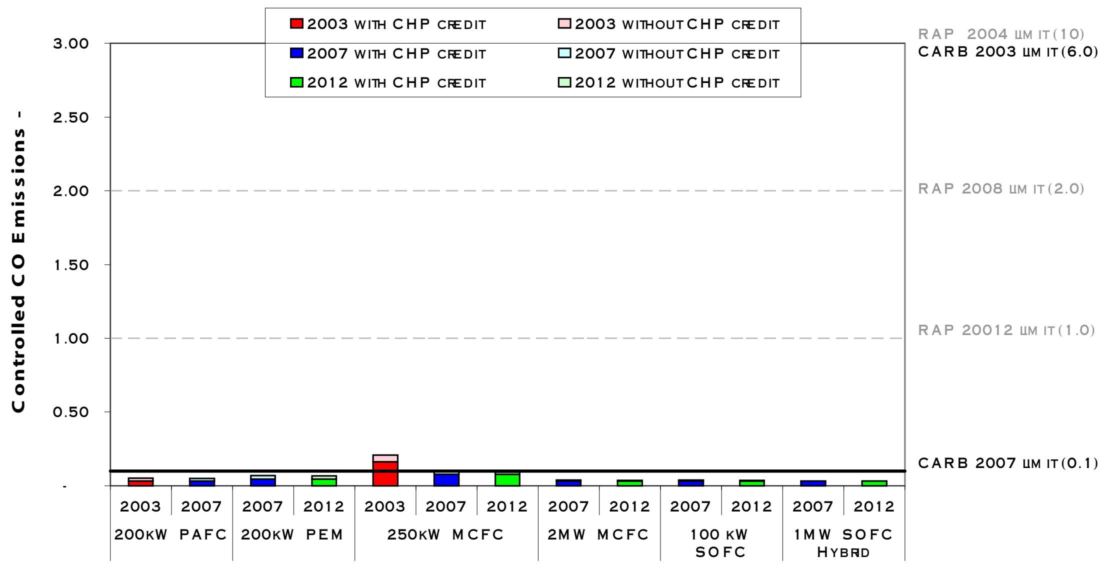
All of the reciprocating engine technologies, as they are configured in the technology profiles, should meet the current CARB CO limit of 6.0 lb/MWh. In 2007, however, the CARB limit changes to 0.1 lb/MWh. The rich burn engines with three way catalysts will struggle to meet the CARB 2007 limits by 2012 even in the accelerated case (not shown). The lean burn engines with oxidation catalysts should meet the CARB 2007 limits by 2012, but only in the accelerated case (not shown on the chart). The reciprocating engines with exhaust gas recirculation and three way catalysts will meet the CARB 2007 limit by 2012 in the base case.

Figure 36 - CO Emissions for Microturbines and Gas Turbines, CARB



All of the microturbine and gas turbine technologies are meeting the current CARB limits for CO. In the base case, microturbines will grapple to meet CARB by 2007 in CHP applications. In the accelerated case microturbines comfortably meet the CARB 2007 limits with the CHP credit. All of the gas turbine technologies will meet the CARB 2007 limit by 2007.

Figure 37 - CO Emissions for Fuel Cells, CARB



All of the fuel cell technologies will meet the impending CARB limit with no after treatment.

Figures 38 through 40 show electric-only and CHP CO emissions for the reciprocating engine, turbine and fuel cell, using the RAP method for calculating the CHP credit. In all cases, the "base" scenario was used for 2007 and 2012. The RAP allowance for calculating the boiler offset credit for CO is much smaller in comparison to the generation standards than the NOx allowance is. This results in a significantly lower CHP credit, as a percentage of the total emission levels, for CO. However, the RAP CO standards are very lenient; 2.0 lb/MWh for 2008 and 1.0 lb/MWh for 2012, compared to the CARB standard of 0.1 lb/MWh for 2007. All of the technologies examined here easily meet the current RAP limit of 10 lb/MWh even without allowing for the CHP credit. Additionally, all of the technologies should meet the 2008 limits by 2007 and the 2012 limits by 2012.

Figure 38 - CO Emissions for Reciprocating Engines, RAP

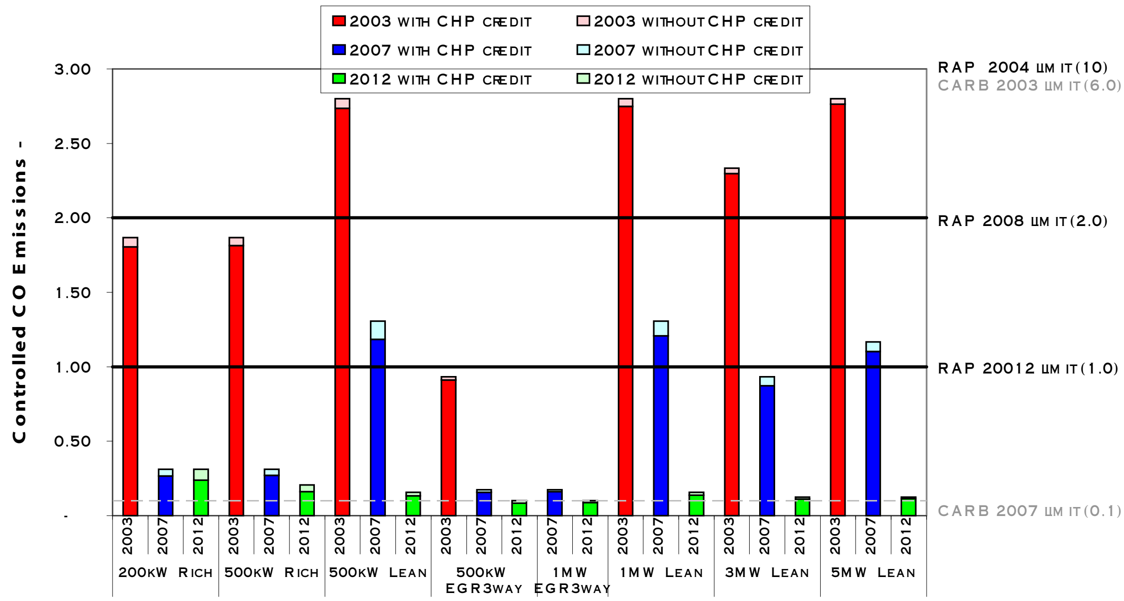


Figure 39 - CO Emissions for Microturbines and Gas Turbines, RAP

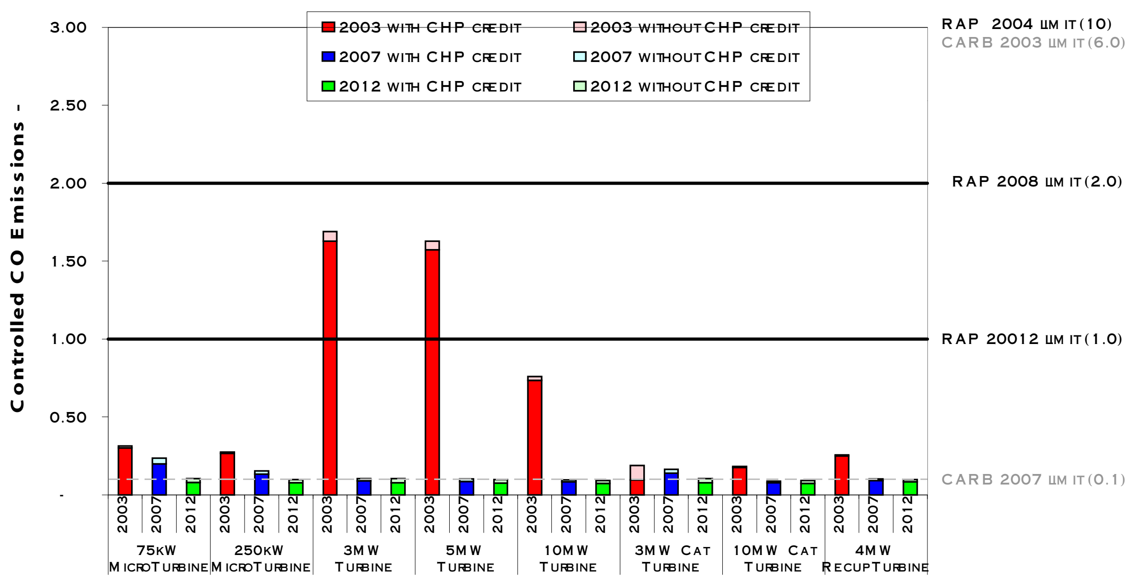
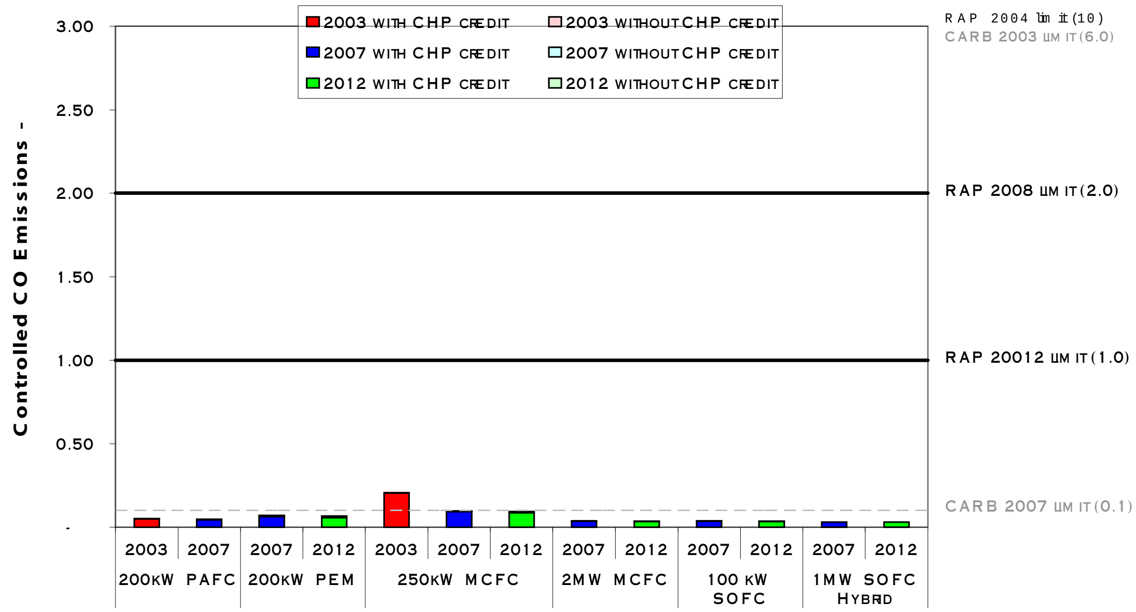


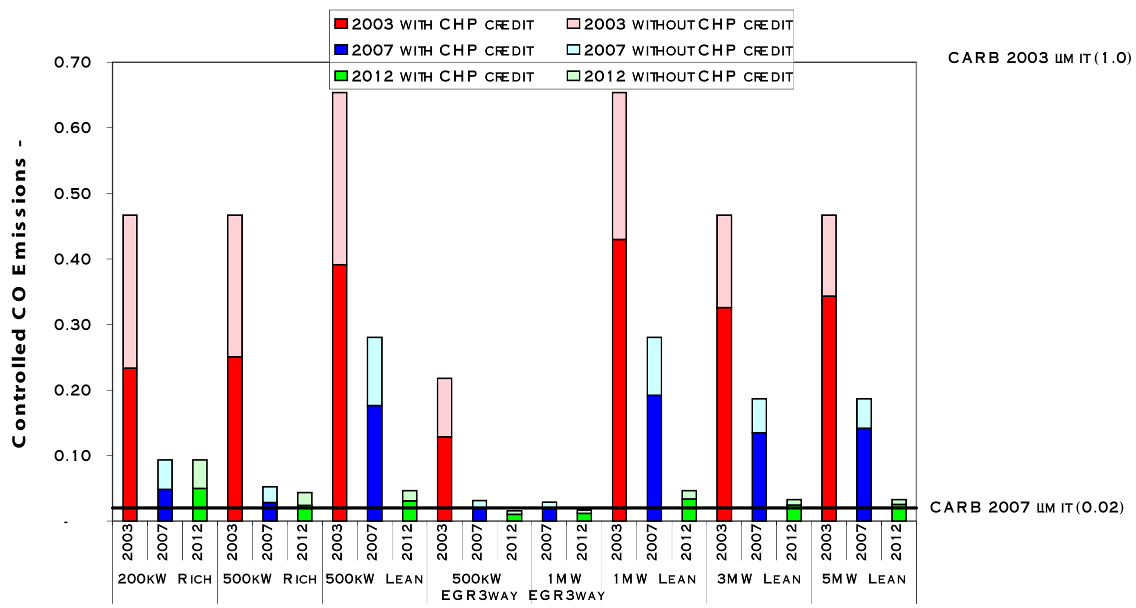
Figure 40 - CO Emissions for Fuel Cells, RAP



<u>VOCs</u>

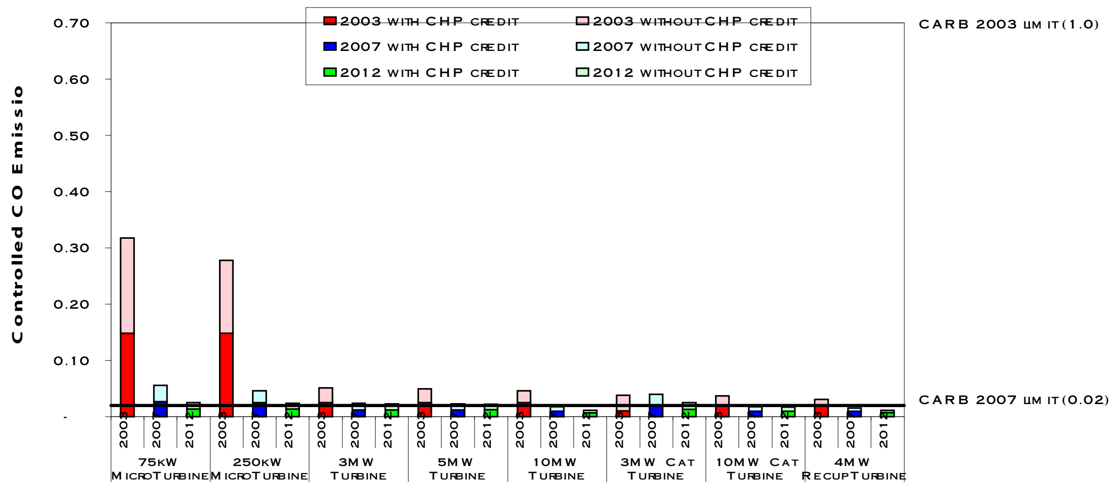
Figures 41 through 43 show electric-only and CHP VOC emissions in California for the reciprocating engine, turbine and fuel cell Technologies. In all cases, the "base" scenario was used for 2007 and 2012. Texas, at this time, does not regulate VOC emissions for DG technologies, and the RAP standard does not specify any VOC levels.

Figure 41 - VOC Emissions for Reciprocating Engines, CARB



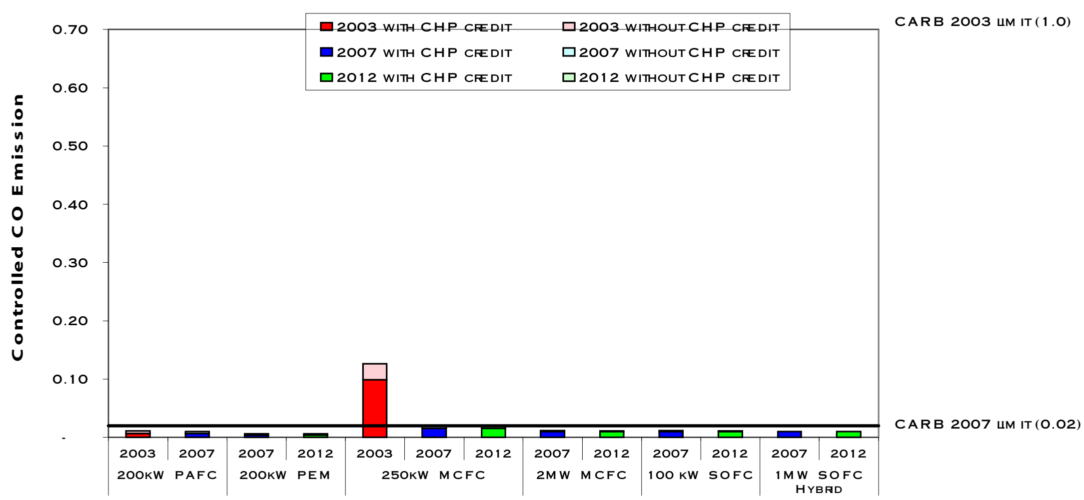
All of the reciprocating engine technologies meet the current CARB limit for VOC emissions even without the CHP credit. The CARB regulation, however, reduces the limit for 2007 by 98% compared to the 2003 limit. The only reciprocating engine technologies that will meet this limit, in the base case, by 2012 are the 3 MW lean burn and those using exhaust gas recirculation and three way catalysts. Both the 500 kW and 1MW EGR engines should meet the limit by 2007. All technologies would meet the 2007 limit by 2012 in the accelerated case.

Figure 42 - VOC Emissions for Microturbines and Gas Turbines, CARB



All of the microturbine and gas turbine technologies meet the current 2003 CARB limit for VOCs without the CHP credit. Both of the microturbines will meet the 2007 CARB limit in 2012, but it's borderline for 2007. All of the other turbine technologies will meet the 2007 CARB limit by 2007.

Figure 43 - VOC Emissions for Fuel Cells, CARB



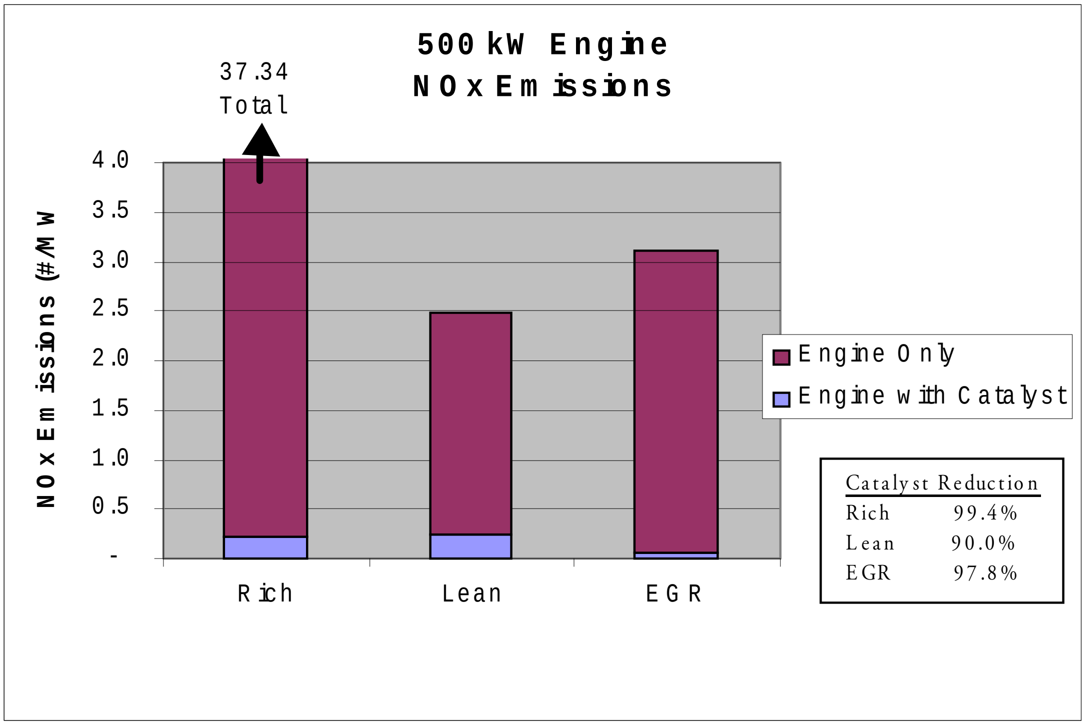
All of the fuel cell technologies will meet the impending CARB limit with no after treatment.

Reciprocating Engine Exhaust Gas Recirculation with 3-Way Catalyst Roadmap

Thanks in part to ongoing DOE and CEC programs, a new approach to achieving low emission levels is showing promise. In principle, the concept adopts the best features of rich-burn and lean-burn technology. Rich burn engines are simple to operate, use a very effective 3-way catalyst for emission reduction, but are limited in power density and engine efficiency. Lean burn engines, using excess air, provide high power density and performance, and engine-out emissions are much lower than rich burn engines. However, exhaust after-treatment on a lean burn engine requires a costly SCR and is limited in its NOx reduction effectiveness. The new concept described below uses exhaust gas recirculation (EGR) instead of excess air, enabling the higher efficiency and lower engine-out emissions approaching the characteristics of lean-burn technology, along with the very high effectiveness and lower cost of 3-way catalysts used with rich burn engines.

The potential for EGR 3-Way engine NOx emissions relative to rich burn and lean burn engines is illustrated below in Figure 44. The 500 kW base case projections for 2007 were used for the comparison.

Figure 44 - Comparison of Engine NOx Control Systems



The top of each bar represents the engine-out NOx emissions. NOx out of a rich burn engine can be 10 – 15 times higher than that out of a lean burn engine. But 3-way catalysts for use on rich burn engines can be 99+% effective with NOx reduction vs. 90%

effective with an expensive SCR on lean burn engines. As shown, the results (NOx levels after catalyst reduction is represented by the lower bars) are similar for the rich burn with 3-way catalyst and for lean burn with SCR. With EGR, engine-out NOx levels are closer to that of lean burn engines. And combined with a 3-way catalyst, resulting NOx levels meeting the CARB 2007 standard can be achieved without fully taxing 3-way catalyst performance.

Other technologies that are still in early stages of development but that may enable yet lower emission levels include hydrogen fuel augmentation, laser ignition, micro-pilot ignition, and homogeneous charge compression ignition (HCCI). It is doubtful that these technologies would be ready commercially within the next five years. With successful technology development and sufficient field experience, EGR 3-Way technology appears to offer both the best near-term and cost-effective solution for ultra low emission regions in the U.S.

Current State of EGR/3-Way Technology

Lab tests have shown the ability of EGR 3-Way Catalyst systems to achieve the 2007 ultra-low levels mandated by CARB. However, field experience is just beginning to be obtained, so that it is still too early to fully understand long-term operation and life effects of EGR on both the engine and 3-Way catalyst. Areas that concern manufacturers and packagers include ignition system robustness, catalyst deterioration, control system stability, and EGR induced engine wear and durability.

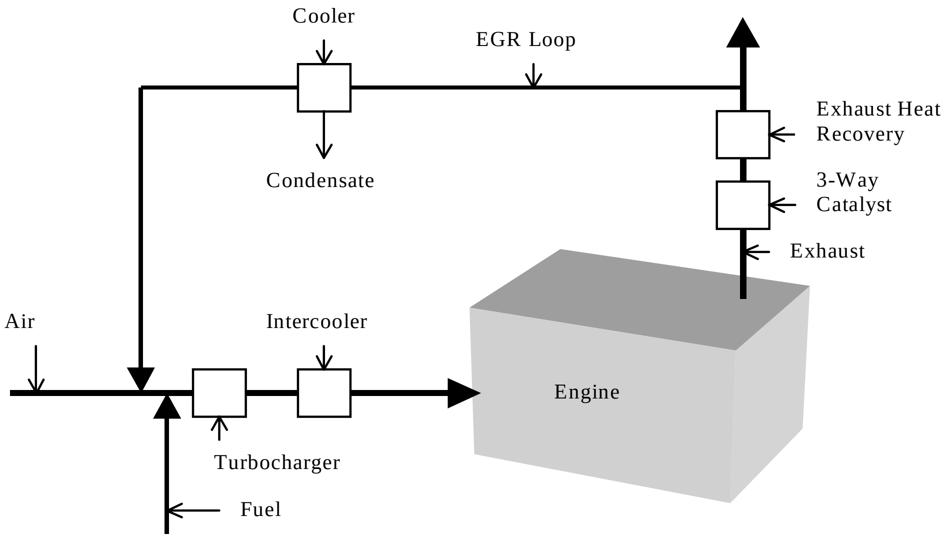
There have been announcements by engine manufacturers and packagers on natural gas engine systems incorporating EGR with a 3-Way catalyst.

- Waukesha Engine Dresser, Inc., with support from the California Energy Commission, has completed laboratory testing of a 500 kW EGR 3-Way engine as part of the CEC's ARICE program, with promising results and is planning a field test in Southern California in Spring 2004.
- DTE has introduced two CHP packages (202 kW, and 350 kW) into the U.S. market with EGR 3-Way. The DTE ultra-low emission package NOx spec is 0.028 g/bhp-hr (0.17 lb/MWh), a level that meets CARB 2007 in CHP applications. The packages were introduced into the European market two years prior and have recently been modified for the U.S. market.
- Blue Point Energy, a CHP system packager, has achieved ultra-low emission levels in the lab using EGR 3-way technology on its 260 kW unit. Although the lab test show promise for CARB 2007, Blue Point has limited experience in the field with their engine packages.
- In 2003 Caterpillar announced the availability of a demonstration engine program using this technology. The Cat designation for the engine is SC-3 for "Stoichiometric, Clean Exhaust Induction, and 3-way Catalyst". Caterpillar specs NO_x emissions at 0.096 gm/hp-hr (0.3 lb/MWh). This is below the 2003 California requirements, but still above the 2007 levels mandated by CARB.

- Attainment Technologies introduced its second generation *GreenGuard* emissions reduction system in late January 2004. Tests conducted by the Gas Technology Institute (GTI) found the retrofit/add-on system will meet CARB 2007 levels.

Technology Description
Figure 45 illustrates the basic concept of an engine equipped with EGR. A fraction of the exhaust stream is cooled and blended with the engine air upstream of the turbocharger and intercooler. Condensate is typically removed from the cooler and disposed of.

Figure 45 - EGR/3-Way Schematic



By using EGR with rich burn fuel/air controls, rather than using excess air with lean burn technology, the exhaust oxygen content remains near zero, allowing a relatively inexpensive and reliable three-way catalyst to be used to achieve extremely low emissions. The recirculated and cooled exhaust gas absorbs heat during combustion without reacting. This reduces the combustion temperature, which reduces NOx formation and allows for the increase in power density and efficiency, similar in principle to the excess air in a lean burn engine.

The higher the EGR charge dilution, the greater the potential for engine out emission reduction and/or engine efficiency increase. EGR dilution enables higher compression ratios be employed for higher power density and efficiency (compared to simple stoichiometric engines). The tradeoff between efficiency and emissions will largely be determined by local air quality regulations.

Technology Barriers
Increasing the amount of EGR amplifies the potential for higher electric efficiencies and reduced emissions. However, as with lean-burn limits with excess air, diluting the fuel/oxygen mixture with too much inert recirculated exhaust gas and lowering the flame temperature reduces combustion stability leading to misfires and poor combustion. Thus, there are limits to the amount of EGR without combustion enhancements.

Also, there is concern that EGR may adversely impact engine durability caused by water and deposits from the exhaust system entering the engine. Of concern is the affect of EGR on the life of pistons, piston rings and cylinder liners. These issues were unveiled in the 1980's when EGR was first considered. It lost support with the ease and successful development of lean burn engines and rich burn engines with 3-Way catalyst.

Another performance issue is the diversion of and cooling of a portion of the exhaust that would otherwise be used to produce high quality (temperature) heat, thus compromising overall efficiency in a combined heat and power application.

Research, Development and Testing Needs
There are near-term and longer-term technical needs associated with EGR/3-Way catalyst engine systems. The near-term requirements are dictated by pending environmental regulations. Critical objectives are to keep pace with ratcheting emission regulations without appreciably compromising cost and durability. Long-term objectives are to take EGR/3-Way technology to the limits of the efficiency, durability and emissions envelope. The performance/cost needs and corresponding technology counter are summarized in Table 5 below.

Table 5 - Market Needs and Technology Solutions

Performance/Cost Need	**Technology Path**
Near-Term (2007)	
2007 CARB Emissions	• 15-20% EGR • Premium 3-Way Catalyst
Maintain Power density	• Higher Compression ratios
Maintain durability expectations	• Incorporate material improvements from on-highway engine programs • Degradation tests on catalysts • Long-term field testing
Efficiency Improvement	• Higher Compression ratios
Longer-Term (2012)	
Maximize EGR for ultra-low emissions and optimal power performance	• Turbo charging and compression ratio increases to boost power density and efficiency with greater EGR • Combustion system enhancements (i.e. hydrogen fuel augmentation, micro-pilot ignition, high energy spark plug, laser ignition) • Advanced EGR/O_2 controls for ultra-low emissions • Optimized catalyst formulation
Heat Utilization Enhancements	• High temperature jacket coolant system (215 – 220 ^oF) • Bifurcated heat exchange on EGR to enable high temperature heat recovery
Durability Improvements	• Optimize material enhancements vs. need for condensate removal and disposal system

Performance and Cost Targets

Recommended near-term and longer-term targets are highlighted below for a 1 MW class engine equipped with EGR and a three-way catalyst.

Table 6 - Recommended Performance and Cost Targets

Target	**Units**	**Near-term (2007)**	**Longer-term (2012)**
Size	MW	1.0	1.0
Installed Cost	$/kW	1,015	965
O&M Cost	$/kWh	0.011	0.010
Electric Efficiency	HHV	37.5%	40.0%
Overall Efficiency	HHV	70%	72%
Emissions			
NOx	lb/MWh	0.07	0.07
CO	lb/MWh	0.17	0.10
VOC	lb/MWh	0.03	0.02

Conclusions

This study finds that plausible technology paths to the ultra-clean levels either have been demonstrated or are being pursued by the four primary CHP technology options. The main issues are timing, the size of the ultra-clean CHP market, availability of resources and ultimate cost to the consumer for ultra-low emissions. Summaries for each of the technology options follow:

Gas Turbines

- The most stringent out-year requirements can be achieved today with SCR and Oxidation catalysts. The economic premium for SCR is in the vicinity of 10%.
- DLE technology for simple cycle turbines should better the 10-ppm NOx level (0.47 lb/MWh) without after-treatment. The cost premium would be minimal. But this falls short of the ultra-low levels required even today in some Air Quality Districts.
- Catalytic combustors and other surface combustion techniques show promise for < 2 ppm NOx (0.07 lb/MWh) without after-treatment, a level that meets the most stringent future requirements. The cost premium would be significantly less than exhaust after-treatment.
- For recuperated gas turbines, the prospects are good for DLE combustors to achieve ultra-low emission performance.

Reciprocating Engines

- With technology investments, rich-burn engines with 3-way catalysts should be able to approach the ultra-low levels in CHP applications.
- Lean-burn engines with after-treatment face the biggest challenge and will require big advances in combustion and SCR technology. Even if technically successful, the after-treatment system will add 15% to the cost of CHP.
- The best path to ultra-low emissions looks to be EGR with 3-way catalyst. The combination of using EGR for lower engine-out emission levels and higher efficiency with lower cost and very effective 3-way catalyst to treat exhaust emissions should achieve ultra-low emissions without seriously compromising efficiency or economics.

Microturbines

- DLE combustors are showing good promise to reach ultra-low levels at full load operating conditions
- Catalytic combustors serve as a backup approach but are not now receiving serious financial support

Fuel Cells

- Inherently very clean
- Primary concerns are economic sustainability in the market

The efficiency, grid support, energy cost saving and reliability benefits of CHP can clash in regions with very stringent environmental requirements. Three notable environmental initiatives directed at CHP have challenged the pace of Clean CHP technology advancement. The result could be the addition of costly after-treatment; a shift to an otherwise less economic technology option, or in some cases a decision not to proceed.

The above summary purports that ultra-low emission solutions exist for all considered CHP technologies. The price premium for ultra-low emissions varies and is greatest for technologies that require SCR after-treatment. The timing of commercial products may not be in sync with emission regulation schedules and is affected by the size of the low emission market and technology resource priorities.

The recognition of a credit for heat recovery will ease the achievement of ultra-low levels. The offset method can make a big difference on the requirements of the prime mover.

Note: This study assumed that costly continuous emission monitoring (CEM) or other complicated methods for measuring heat utilization in the field will not be required. Such measures can complicate the investment decision, add risk and cost, and jeopardize project viability, particularly in the smaller sizes.

Recommendations

The following recommendations are provided:

- Continued DOE and CEC support for cost-effective ultra-low emission CHP solutions
- Investigation of effectiveness and cost of various heat recovery measurement protocols
- Outreach of study results to State Environmental officials, including assistance to key States developing DG and CHP emission regulations in concert with technology progress
- Scheduled Workshops on ultra-clean reciprocating engine system technology
- Advocate adequate lead-time for technology and product development for any new emission standard
- Encourage federal, state and utility incentives to encourage the development and commercial acceptance of advanced CHP systems

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Appendix A

Sample Data Sheets

Equipment Class 500kW Class Lean Burn Engine

Regulation Reference RAP

		2003/2004				2007						2012			
Baseline Definition w/o Aftertreatment		Typical	Note #	Limited	Note #	Base	Note #	Accelerated	Note #	Limited	Note #	Base	Note #	Accelerated	Note #
• Rate Capacity Continuous	kWe	500		500		500		500		500		500		500	
• Electrical Efficiency	% LHV	35.9%		36.7%		37.8%		38.9%		37.8%		40.0%		41.1%	
• Electrical Efficiency	% HHV	32.3%		33.0%		34.0%		35.0%		34.0%		36.0%		37.0%	
• Overall CHP Efficiency	% HHV	55%		55%		55%		55%		55%		55%		55%	
• Installed Capital Cost PO (1)	$/kWe	$ -		$ -		$ -		$ -		$ -		$ -		$ -	
• Installed Capital Cost CHP (1)	$/kWe	$ 1,200		$ 1,200		$ 1,150		$ 1,150		$ 1,150		$ 1,100		$ 1,100	
• O&M Costs (2)	$/kWh	$ 0.0125		$ 0.0125		$ 0.0120		$ 0.0115		$ 0.0120		$ 0.0115		$ 0.0110	
• NOX Baseline Equipment (3)	lb/MWh (e)	3.11		3.11		2.49		1.87		2.49		1.87		1.56	
	lb/MWh (chp)	1.56		1.08		0.91		0.71		0.55		0.47		0.41	
	ppm @ 15%	78.8		80		66.3		51		66		52.7		45	
	gm/bhp-hr	1.000		1.000		0.800		0.600		0.800		0.600		0.500	
• CO Baseline Equipment (3)	lb/MWh (e)	9.34		9.34		8.71		7.78		8.40		7.78		7.78	
	lb/MWh (chp)	9.12		8.39		7.89		7.09		6.94		6.60		6.68	
	ppm @ 15%	343		351		337		310		325		319		328	
	gm/bhp-hr	3.000		3.000		2.800		2.500		2.700		2.500		2.500	
• VOC Baseline Equipment (3)	lb/MWh (e)	2.18		2.18		1.87		1.56		1.87		1.56		1.24	
	lb/MWh (chp)	1.28		1.31		1.15		0.99		1.15		1.02		0.84	
	ppm @ 15%	131.9		135		119.0		102		119		105.0		86	
	gm/bhp-hr	0.700		0.700		0.600		0.500		0.600		0.500		0.400	
• CO2 Baseline Equipment (3)	lb/kWh (e)	1.24		1.21		1.17		1.14		1.17		1.11		1.08	
	lb/kWh (chp)	1.043		1.029		1.010		0.991		0.989		0.956		0.940	
Aftertreatment Technology (AT)		SCR & Ox Cat		SCR & Oxidation Catalyst						SCR & Oxidation Catalyst					
• Incremental Capital Cost PO (1)	$/kWe	$ 300		$ 250		$ 225		$ 200		$ 200		$ 180		$ 160	
• Incremental Capital Cost CHP (1	$/kWe	$ 300		$ 250		$ 225		$ 200		$ 200		$ 180		$ 160	
• O&M Costs (2)	$/kWh	$ 0.0056		$ 0.0056		$ 0.0052		$ 0.0049		$ 0.0056		$ 0.0052		$ 0.0045	
• NOX Conversion	%	89.3%		90.0%		90.0%		92.9%		90.4%		91.8%		92.9%	
• NOX Controlled (3)	lb/MWh (e)	0.33		0.31		0.25		0.13		0.24		0.15		0.111	
	lb/MWh (chp)	0.17		0.11		0.09		0.05		0.05		0.04		0.03	
	ppm @ 15%	8		8		6.6		4		6		4.3		3	
	gm/bhp-hr	0.107		0.100		0.080		0.042		0.077		0.049		0.036	
• CO Conversion		70%		75%		85%		95%		90%		98%		98%	
• CO Controlled (3)	lb/MWh (e)	2.80		2.33		1.31		0.39		0.84		0.16		0.16	
	lb/MWh (chp)	2.74		2.10		1.18		0.35		0.69		0.13		0.13	
	ppm @ 15%	103		88		51		15		33		6		7	
	gm/bhp-hr	0.900		0.750		0.420		0.125		0.270		0.050		0.050	
• VOC Conversion		70%		75%		85%		95%		90%		97%		98%	
• VOC Controlled (3)	lb/MWh (e)	0.65		0.54		0.28		0.08		0.19		0.05		0.02	
	lb/MWh (chp)	0.38		0.33		0.17		0.05		0.12		0.03		0.02	
	ppm @ 15%	39.6		33.7		17.9		5.1		11.9		3.2		1.7	
	gm/bhp-hr	0.210		0.175		0.090		0.025		0.060		0.015		0.008	
• CO2 Conversion		0%		0%		0%		0%		0%		0%		0%	
• CO2 Controlled (3)	lb/kWh (e)	1.24		1.21		1.17		1.14		1.17		1.11		1.08	
	lb/kWh (chp)	1.043		1.029		1.010		0.991		0.989		0.956		0.940	
• Capacity Derating	% of Baseline	0%		0%		0%		0%		0%		0%		0%	
• Efficiency Derating	% of Baseline	0.0%		0.0%		0.0%		0.0%		0.0%		0.0%		0.0%	

Conversions	NOX	CO	VOC	CO2
gm/mole	40.7	28.0	17.0	117.0
(%eff,LHV)*(lb/MW-hr) per 1 ppm @15%O2	0.01418	0.00977	0.00593	lb/MMBtu
(%eff,LHV)*(lb/MW-hr) per (lb/MMBtu input HHV)	3.791	3.791	3.791	
(lb/MW-hr) per (gm/bhp-hr)	3.112	3.112	3.112	

HU Factor
100%
Gen Eff.
95.0%

1) PO is Power Only and CHP is Combined Heat & Power. Capital Cost are without emission controls (EC).

2) O&M Costs include sinking fund for overhauls and catalyst replacements.

3) All emissions are in lb/MWe-hr in 2003/2004 and in both lb/MWe-hr & lb/MW-hr with CHP credit in 2007 and 2012.

4) All costs are current dollars

Limited Column

Limited market and technology development

Limited market competition

Limited funding for technology development and support

Market and economic conditions degrade for CHP

Base Column

Best estimate based on current market and technology t

Accelerated Column

Accelerated market and technology development

Robust market activity and competition

Equipment Class 500kW Class Lean Burn Engine

Regulation Reference CARB

		2003/2004		2007						2012					
Baseline Definition w/o Aftertreatment		Typical	Note #	Limited	Note #	Base	Note #	Accelerated	Note #	Limited	Note #	Base	Note #	Accelerated	Note #
• Rate Capacity Continuous	kWe	500		500		500		500		500		500		500	
• Electrical Efficiency	% LHV	35.9%		36.7%		37.8%		38.9%		37.8%		40.0%		41.1%	
• Electrical Efficiency	% HHV	32.3%		33.0%		34.0%		35.0%		34.0%		36.0%		37.0%	
• Overall CHP Efficiency	% HHV	54%		54%		54%		54%		54%		54%		54%	
• Installed Capital Cost PO (1)	$/kWe	$ -		$ -		$ -		$ -		$ -		$ -		$ -	
• Installed Capital Cost CHP (1)	$/kWe	$ 1,200		$ 1,200		$ 1,150		$ 1,150		$ 1,150		$ 1,100		$ 1,100	
• O&M Costs (2)	$/kWh	$ 0.0125		$ 0.0125		$ 0.0120		$ 0.0115		$ 0.0120		$ 0.0115		$ 0.0110	
• NOX Baseline Equipment (3)	lb/MWh (e)	3.11		3.11		2.49		1.87		2.49		1.87		1.56	
	lb/MWh (chp)	1.86		1.90		1.57		1.21		1.57		1.24		1.07	
	ppm @ 15%	78.8		80		66.3		51		66		52.7		45	
	gm/bhp-hr	1.000		1.000		0.800		0.600		0.800		0.600		0.500	
• CO Baseline Equipment (3)	lb/MWh (e)	9.34		9.34		8.71		7.78		8.40		7.78		7.78	
	lb/MWh (chp)	5.58		5.71		5.49		5.04		5.29		5.19		5.33	
	ppm @ 15%	343		351		337		310		325		319		328	
	gm/bhp-hr	3.000		3.000		2.800		2.500		2.700		2.500		2.500	
• VOC Baseline Equipment (3)	lb/MWh (e)	2.18		2.18		1.87		1.56		1.87		1.56		1.24	
	lb/MWh (chp)	1.30		1.33		1.18		1.01		1.18		1.04		0.85	
	ppm @ 15%	131.9		135		119.0		102		119		105.0		86	
	gm/bhp-hr	0.700		0.700		0.600		0.500		0.600		0.500		0.400	
• CO2 Baseline Equipment (3)	lb/kWh (e)	1.24		1.21		1.17		1.14		1.17		1.11		1.08	
	lb/kWh (chp)	0.985		0.974		0.960		0.946		0.960		0.932		0.919	
Aftertreatment Technology (AT)		SCR & Ox Cat				SCR & Oxidation Catalyst						SCR & Oxidation Catalyst			
• Incremental Capital Cost PO (1)	$/kWe	$ 300		$ 250		$ 225		$ 200		$ 200		$ 180		$ 160	
• Incremental Capital Cost CHP (1	$/kWe	$ 300		$ 250		$ 225		$ 200		$ 200		$ 180		$ 160	
• O&M Costs (2)	$/kWh	$ 0.0056		$ 0.0056		$ 0.0052		$ 0.0049		$ 0.0056		$ 0.0052		$ 0.0045	
• NOX Conversion	%	89.3%		90.0%		90.0%		92.9%		90.4%		91.8%		92.9%	
• NOX Controlled (3)	lb/MWh (e)	0.33		0.31		0.25		0.13		0.24		0.15		0.111	
	lb/MWh (chp)	0.20		0.19		0.16		0.09		0.15		0.10		0.08	
	ppm @ 15%	8		8		6.6		4		6		4.3		3	
	gm/bhp-hr	0.107		0.100		0.080		0.042		0.077		0.049		0.036	
• CO Conversion		70%		75%		85%		95%		90%		98%		98%	
• CO Controlled (3)	lb/MWh (e)	2.80		2.33		1.31		0.39		0.84		0.16		0.16	
	lb/MWh (chp)	1.68		1.43		0.82		0.25		0.53		0.10		0.11	
	ppm @ 15%	103		88		51		15		33		6		7	
	gm/bhp-hr	0.900		0.750		0.420		0.125		0.270		0.050		0.050	
• VOC Conversion		70%		75%		85%		95%		90%		97%		98%	
• VOC Controlled (3)	lb/MWh (e)	0.65		0.54		0.28		0.08		0.19		0.05		0.02	
	lb/MWh (chp)	0.39		0.33		0.18		0.05		0.12		0.03		0.02	
	ppm @ 15%	39.6		33.7		17.9		5.1		11.9		3.2		1.7	
	gm/bhp-hr	0.210		0.175		0.090		0.025		0.060		0.015		0.008	
• CO2 Conversion		0%		0%		0%		0%		0%		0%		0%	
• CO2 Controlled (3)	lb/kWh (e)	1.24		1.21		1.17		1.14		1.17		1.11		1.08	
	lb/kWh (chp)	0.985		0.974		0.960		0.946		0.960		0.932		0.919	
• Capacity Derating	% of Baseline	0%		0%		0%		0%		0%		0%		0%	
• Efficiency Derating	% of Baseline	0.0%		0.0%		0.0%		0.0%		0.0%		0.0%		0.0%	

Conversions	NOX	CO	VOC	CO2
gm/mole	40.7	28.0	17.0	117.0
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(lb/MW-hr) per (gm/bhp-hr)	3.112	3.112	3.112	

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