Arnold Schwarzenegger
Governor

PIER ADVANCED GENERATION ROADMAP - BACKGROUND PAPER

DRAFT CONSULTANT REPORT

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Prepared By:
Navigant Consulting, Inc.

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Preface

The California Energy Commission's Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

PIER Advanced Generation Roadmap Background Paper is the interim report for the PIER AG project 500-06-012, Work Authorization Number NCI-06-027-P-R conducted by Navigant Consulting. The information from this project contributes to PIER's Advanced Generation Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916-654-4878.

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Table of Contents

List of Figures

List of Tables

Abstract

The Advanced Generation (AG) program is one of the key focus areas for the Public Interest Energy Research (PIER) Program. Over the last 10 years, PIER AG has invested $102 million in advanced electricity generation, which is roughly 20 percent of its research, development and demonstration (RD&D) funding. Distributed generation and combined heat and power systems have been a key research focus area for the PIER AG program in the past. The program is developing a roadmap and considering including larger scale advanced generation technologies in addition to its traditional focus on distributed generation technologies. Investing in advanced generation technology provides an opportunity for developing clean, reliable, affordable, secure, and sustainable power. This paper will examine the state and federal policy framework for advanced generation in California, assess the current status of advanced generation technologies, and identify significant trends and issues as well as strategic opportunities for PIER Advanced Generation RD&D.

Keywords: Advanced generation, roadmap, distributed generation, combined heat and power, emissions, policies

Executive Summary

Policy Framework

Significant California policy goals and directives related to non-renewable electricity generation, large-scale or distributed, are:

- Statewide greenhouse gas (GHG) emissions will be limited to 1990-equivalent levels by 2020 (Assembly Bill 32 [Nuñez, Chapter 488, Statutes of 2006]).
- Reduce GHG emissions to 2000 levels by 2010, to 1990 levels by 2020, and to 80 percent below 1990 levels by 2050 (Governor's Executive Order - S-3-05).
- Install 4,000 MW of additional combined heat and power capacity by 2020 (California Air Resources Board [ARB] AB 32 Scoping Plan).
- Use combined heat and power so that new construction is net zero energy by 2020 for residences and 2030 for commercial buildings (*2007 Integrated Energy Policy Report* [*2007 IEPR*]).
- By 2012, repower aging power plants or retire and replace with cleaner technologies (*2005 IEPR*).
- Phased elimination of once-through cooling between 2015 and 2021 (*2008 IEPR Update*).

California policy goals include reducing emissions and environmental impacts from electricity generation. While there are no specific goals for efficiency in natural gas power plants, the state's primary source of generation, goals may be implied through generation emissions standards. Further, although the state has not yet developed specific targets or goals, it is interested in carbon capture and sequestration research.

Current Status of Advanced Generation Technologies

This paper covers 20 primary focus technology areas organized into five groups, and six secondary focus technology areas, organized into three groups, Table 1. The primary focus technologies directly pertain to PIER Advanced Generation. The secondary focus technologies are mainly addressed by other PIER research areas. However, Advanced Generation is participating in the research and coordination of the secondary focus technologies and is providing its support.

Table 1. Advanced Generation Technologies Profiled

Primary Focus Technologies	*Secondary Focus Technologies*
• Distributed Generation/Combined Heat and Power - Fuel Cells - Hybrid Fuel Cell Gas Turbine Cycles - Reciprocating Engines - Stirling Engines - Microturbines - Gas Turbines • Cooling - Absorption Chillers • Advanced Gas Turbine Cycles - Industrial Cogeneration - Inlet Cooling - Recuperation - Intercooled/recuperated - Heat recovery - Advanced Simple Cycle for Peaking - Hybrid Renewable Cycles - Integrated Gasification Simple Cycle • Replacement for Once-Through Cooling - Dry Cooling - Wet Cooling Towers - Alternative Cooling Water - Hybrid Cooling Towers • Carbon Reduction - Pre-Combustion Capture	• Advanced Coal/Biomass Combustion - Integrated Gasification Combined Cycle - Ultra-Supercritical Pulverized-Coal - Supercritical Circulating Fluidized-Bed Combustion • Carbon Capture and Sequestration - Post-Combustion Capture - Geological Sequestration • Advanced Nuclear Power Generation - Advanced Boiling Water Reactor (ABWR) Advanced Pressurized Water Reactor (APWR)

Source: Navigant Consulting, Inc.

Key conclusions from the profiles of each group of technologies are:

Distributed Generation/Combined Heat and Power

- Cost is still a limiting factor for widescale adoption of most distributed generation technologies.
- Combined heat and power is typically the most cost-effective application for distributed generation.
- There is a recent trend in research on fuel flexibility of distributed generation/combined heat and power systems, specifically targeting alternative fuels and other low-value fuels.
- There has been limited investment in communication and control technologies for distributed generation and combined heat and power systems that would ease integration with the smart grid.
- California Electric Rule 21–Generating Facility Interconnections (Rule 21) has been successful in removing interconnection barriers.

- Hybrid Fuel Cell–Gas turbine cycle systems have the highest efficiency among Distributed Generation technologies.
- A large amount of funding is going to transportation fuel cells, with limited research funding going to stationary power fuel cells.
- As transportation technology research becomes more focused on plug-in hybrid technologies and moves away from fuel cells, this could also lead to reduced funding for stationary fuel cell research.
- PIER and the Electricity Analysis Office are funding an industrial combined heat and power market potential study, as well as an update to the 2005 combined heat and power market potential study.

Cooling / Combined Cooling Heating and Power

- Absorption chillers are currently the primary technology used in combined cooling, heating, and power systems.
- Electric driven chillers are another important technology used in combined cooling, heating, and power systems.
- High cost, relative to the efficiency benefits, is the main barrier for widescale adoption of combined cooling, heating, and power.
- While overall combined heat and power efficiency is generally lower for systems paired with absorption chillers relative to other combined heat and power systems, the primary benefits of using the technology in warmer climates are effective usage of waste heat.

Advanced Gas Turbine Cycles

- Most of the advanced gas turbine cycle technologies are mature, and most new power plant projects typically incorporate these technologies.
- There is a significant opportunity to improve efficiency from existing power plants by retrofitting them with advanced gas turbine cycle technologies.
- In recent years, there has been limited research on developing new gas turbine cycle technologies; most of the research in these technologies was performed more than 10 years ago.
- There has been limited effort to demonstrate the benefits of the technologies in retrofit applications.
- Recent research has been primarily focused on materials, by the original equipment manufacturers.
- There has been a significant amount of research outside the United States on hybrid renewable systems that address the intermittency of renewables.

- While there are significant incentives in place for renewable systems, hybrid systems do not qualify for these incentives, and there are few incentives available for hybrid renewable systems.
- There is a large technical potential for industrial cogeneration and heat recovery that has not been realized.

Replacement for Once-Through Cooling

- Equipping power plants that currently use once-through cooling (OTC) with any of the alternative technologies may be expensive and may affect the plant efficiency.
- Older power plants will likely shut down as a result of the policy to eliminate once-through cooling.
- The cost of power plant cooling systems is highly dependent on the site.
- Typically, dry cooling is the most expensive alternative, followed by hybrid cooling, then closed-cycle wet cooling towers.
- Even though wet cooling towers can use sea water, they still represent a significant improvement over OTC since they use only a small percentage of the amount of water used in OTC.
- Space (for example, for cooling tower) could be a limiting factor in retrofitting some plants with an alternative cooling system.

Pre-Combustion Carbon Capture

- Cost of pre-combustion carbon capture systems (for example, systems that capture carbon before combustion) varies widely between new plants and retrofits.
- Cost of retrofitting existing plants with pre-combustion carbon capture systems is typically prohibitive.
- Cost of these systems is dependent on the amount of carbon in the fuel source; however, the cost/ton of carbon is still lower with a dirtier fuel (for example, coal), while the cost per megawatt hour (MWh) is lower with a cleaner fuel (for example, natural gas).
- Lack of utility-scale demonstrations has limited the adoption of this technology; the American Recovery Reinvestment Act of 2009 has allocated funding for utility-scale demonstrations.
- United States Department of Energy expects that new research on this technology could lead to significant cost reductions.
- Integrated gasification combined-cycle is a process that converts coal to gas that is used to power a gas turbine whose waste heat is passed to a steam turbine system. Integrated gasification combined-cycle with pre-combustion capture has the lowest energy requirements for capture, 0.194 kilowatt hour per kilogram (kWh/kg) of carbon dioxide

(CO_2) processed, compared to 0.317 kWh/kg of CO_2 processed for natural gas combined-cycle plants with post-combustion capture.

- IGCC with pre-combustion capture shows the most long-term promise for carbon capture and sequestration (CCS).
- Little research has been done on pre-combustion capture for natural gas plants and opportunities exist, such as the use of integrated gasification simple-cycle (for example, process that uses exhaust heat to chemically reform fuel feedstock, typically natural gas, into a higher calorific flow fuel stream containing a significant concentration of hydrogen).
- The success of pre-combustion carbon capture technologies will depend on the success of carbon sequestration technologies.

Advanced Coal/Biomass Combustion

- There is limited electricity generated from coal in California; however, 17 percent of power consumed in the state is imported from coal power plants outside the state.
- The Energy Commission has invested some resources, but relatively much smaller than US DOE investments, for the development and demonstration of advanced coal/biomass combustion technologies.
- Repowering old coal plants that export power to California with advanced coal combustion technologies could provide a significant carbon reduction opportunity.

Carbon Capture and Sequestration

- The opportunity for carbon capture and sequestration in California is mostly tied to natural gas power plants linked to enhanced oil recovery.
- Post-combustion capture is better suited for retrofitting of existing power plants.
- Post-combustion capture technology is more cost-effective for coal plants than for natural gas plants.
- Post-combustion capture is more energy-intensive than pre-combustion capture.
- Post-combustion capture technology requires additional development and cost improvement.
- Compared to other carbon reduction approaches, carbon capture is more expensive.
- The success of oil recovery carbon sequestration depends on the alignment of interest between the oil producer and society’s need to reduce carbon emissions.

Advanced Nuclear Power Generation

- Various advanced nuclear power technologies are competing for combined construction and operating licenses and will be the first nuclear reactors built in the United States over the last 20 years.
- The earliest a new nuclear reactor could be operational in the United States would be about 2016.
- The cost of building an advanced nuclear power plant in the United States is highly uncertain given that no nuclear power plants have been built recently.
- There is still no facility for nuclear waste disposal.
- Existing research abroad (for example, China) is focused on early-stage modular technologies.
- California's moratorium on building new nuclear power generation would have to be lifted to allow for new nuclear power.

Key Trends and Issues

Overall, California has significant electricity resources that are already cleaner but less affordable than the U.S. average. To reduce GHG emissions from electricity generation, the state has adopted a series of energy policies. Among these policies, the Renewables Portfolio Standard is estimated to reduce generation from natural gas by 20-45 percent by 2020 in one study.[1] A recent study in support of the *2009 IEPR* found that generation from natural gas could be reduced 15 percent by 2020 under existing state energy policy.[2] In either case, natural gas continues to play a role in electricity generation. California may need to replace/repower 66 aging gas power plants with a combined capacity of 17,000 MW (40 percent of in-state gas-fired power plants and 25 percent of all in-state capacity) by 2012. The scope/timeframe of this goal is under review.

As California confronts a limited water supply, 20 desalination plants have been proposed statewide. Improvements have lessened the thermal and pumping energy required for the desalination processes, but the energy intensity remains high. Energy and greenhouse gas emissions impacts will need to be considered when assessing desalination projects.

Zero net energy new construction initiatives by the California Public Utilities Commission (residential by 2020 and commercial by 2030) could have a significant impact on energy efficiency and distributed generation. Statewide smart grid initiatives are expected to increase the value of photovoltaic (PV) and other distributed generation systems; however, realizing the

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[1] Source: Lesser, Jonathan, Paul Lowengrub, Spencer Yang. *A Mean-Variance Portfolio Optimization of California's Generation Mix to 2020: Achieving California's 33 Percent Renewable Portfolio Standard Goal -* DRAFT CONSULTANT REPORT. California Energy Commission, PIER Program. CEC-300-2007-009-D

[2] Source: Tanghetti, Angela, Karen Griffin, 2009. *Impacts of AB 32 Scoping Plan Electricity Resource Goals on Natural Gas-Fired Generation*. California Energy Commission. CEC-200-2009-011.

expected value will require coordinated involvement of various stakeholders. The state may need to overcome technical and non-technical challenges posed by the intermittency of renewable generation, both distributed and large scale.

Strategic Opportunities

A new vision statement for the PIER AG program enables PIER AG to play a key role in helping the state meet key policy goals. The preliminary vision statement is:

> *The PIER AG program provides key RD&D that enables California to generate energy efficient, abundant, affordable, reliable, and environmentally-friendly electricity (and other forms of power) from small to large power plants, including distributed generation and combined heat and power, using clean non-renewable fuels and fuel flexibility capability in order to help reach the greenhouse gas emission reduction targets.*

Keeping with this vision, PIER AG would focus on improving efficiency and reducing GHG emissions of large-scale and distributed generation systems fueled with clean fuels like natural gas and fuel flexible. Three main program areas are:

- Commercial combined heat and power/combined cooling, heating, and power systems – Support development of cost-effective combined heat and power and combined cooling, heating, and power systems for commercial buildings and their widescale deployment.
- Industrial combined heat and power /Cogeneration Systems – Support development of cost-effective industrial combined heat and power/cogeneration systems and their widescale deployment.
- Advanced Gas Turbine Cycles – Support development and widescale adoption of cost-effective advanced gas turbine cycles, including integrated hybrid renewable systems that significantly improve the efficiency and fuel flexibility of natural gas power plants.

Also, PIER AG will continue coordinating and providing support while avoiding duplication of efforts and funding research addressed by other PIER research areas. For example:

- Residential single family combined heat and power/combined cooling, heating, and power systems – Technologies currently not cost-effective as thermal load too small relative to electricity load. Continue to monitor technology progress as there is a high technical potential for residential combined heat and power /combined cooling, heating, and power systems.
- Distributed generation systems primarily used for emergency baseload, peaking, backup, and cycling applications – Primary focus on more efficient, cost-effective, and environmentally friendly combined heat and power systems.

- Distributed generation/combined heat and power interconnection rules and standards – Addressed by smart grid research area of the PIER Energy Systems Integration program.
- Renewables, including management of intermittency issues through the co-location of renewable systems and traditional gas-fueled generation systems – Addressed by the PIER Renewable Energy Technologies program.
- Water use in power plants, including replacement technologies for once-through cooling – Addressed by the PIER Environmental Area and PIER Industrial/Agricultural/Water End-Use Energy Efficiency program.
- Carbon capture and sequestration – Primarily focused on coal fueled generation and addressed by US DOE. Continue to monitor cost-effectiveness of application to natural gas-fueled power generation as under the West Coast Regional Carbon Sequestration Partnership (WESTCARB) and relevant to California.
- Nuclear – Moratorium still in place. Continue monitoring advances in the nuclear technology.

Key Research Issues

In each target research area, PIER AG is considering focusing on some key issues:

- Commercial combined heat and power/combined cooling, heating, and power systems – The primary issue is system packaging and integration. Market and regulatory mechanisms are a secondary issue, to complement the Energy Commission's combined heat and power program.
- Industrial CHP/CCHP Systems – The primary issue is system packaging and integration. Identification of cost-effective sites and market and regulatory mechanisms is a secondary issue, to complement the Energy Commission's combined heat and power program.
- Advanced Gas Turbine Cycles – The primary issues are new technology development of integrated hybrid renewable cycle systems and as new technology demonstration of advanced generation technologies. Market and regulatory mechanisms are a secondary issue, to support policy development.

Stakeholder Input

Stakeholder input is a critical element of the roadmap development process. Expertise in advanced generation technologies is widely spread across various stakeholder groups, including utilities, equipment manufacturers, research organizations, and policy makers. The roadmap development process involves seeking input from these groups.

1.0 Introduction

1.1. Overview of PIER

The PIER program, within the California Energy Commission (Energy Commission,) was established in 1996 as part of new legislation that includes a requirement that at least $62.5 million be collected annually from investor-owned utility ratepayers for "public interest" energy research and development efforts that are not adequately provided by competitive and regulated markets.

As seen in Figure 1, advanced generation has been a key focus area for the PIER Program over the last 10 years.

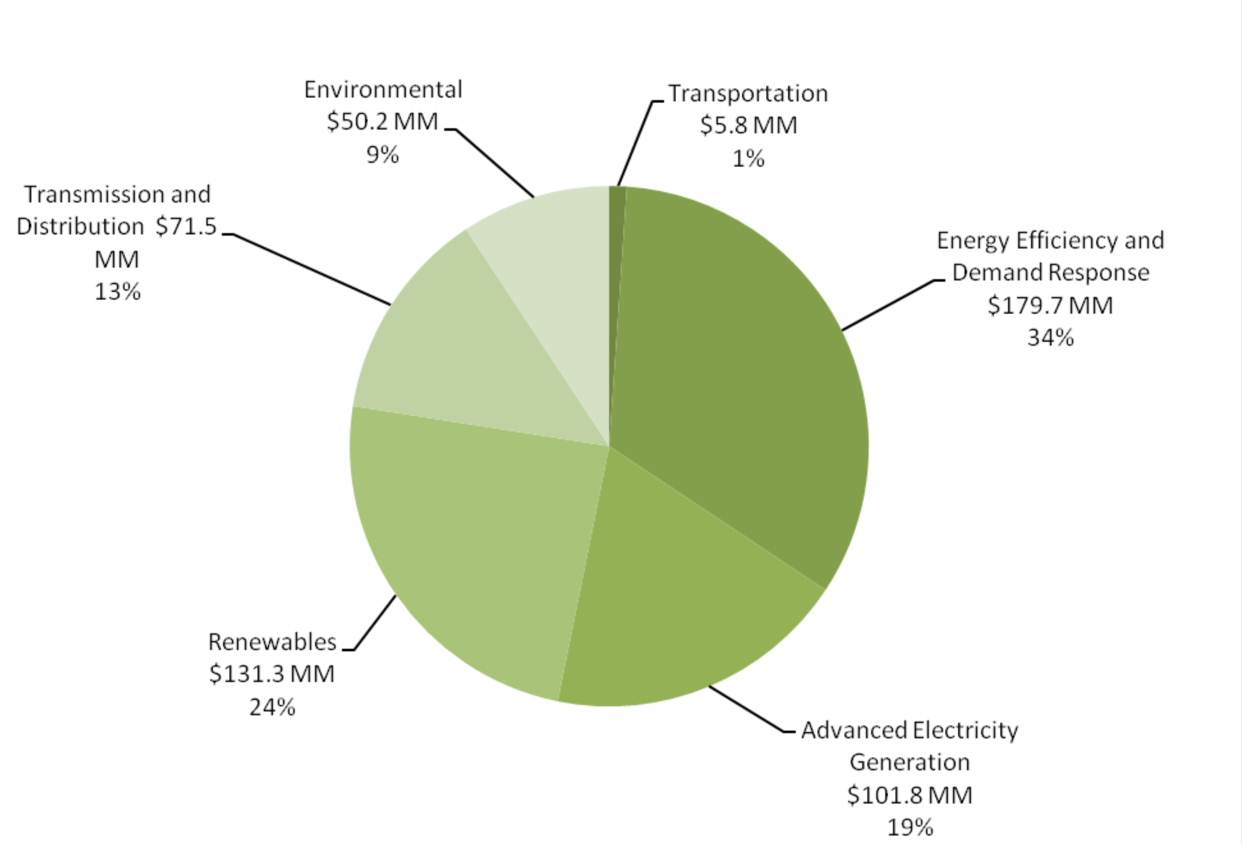

Figure 1. PIER Research Investments by Research Program Area (1997-2007)
Source: *PIER 2008 Annual Report*

1.2. Overview of PIER Advanced Generation

The PIER AG program (formerly known as Environmentally Preferred Advanced Generation or EPAG) funds research, development, and demonstration (RD&D) of advanced generation technologies for deployment and developing new applications, exceeding performance (energy efficiency, environmental) and customer/user expectations (reliability, availability, affordability, maintainability, durability and usability) in the future for cutting edge, game changing, paradigm shift, and advancing the continuum of power generation technologies. The primary focus areas of the program are non-renewable electricity generation resources in California, such as natural gas, and combined heat and power/cogeneration, but with appropriate context of oil, coal, and nuclear as well as renewables.

PIER AG links to several other PIER program areas:

- Building End-Use Energy Efficiency – (end use): Generation and supply-side energy efficiency is equally important.
- Renewable Energy Technologies – power generation from renewables, fuel flexibility, intermittency.
- Industrial/Agricultural/Water End-Use Energy Efficiency – mechanical (for example, lettuce evaporating cooling fan), thermal (combined heat and power, steam and power generation, cogeneration), electricity for pumping water.
- Energy-Related Environmental Research – lessen negative impact on the environment by developing clean generation technologies.
- Transportation – similar prime movers, public transportation, plug-in hybrids.
- Energy Systems Integration – transmission distribution, smart grid, distributed energy resources (DERs) (DGs and CHPs) and their dispatchability.

The PIER AG program collaborates with key stakeholders across the advanced electric generation sector. Stakeholder groups include:

- Manufacturers (engine, turbines, fuel cells, boilers, combustors, CHP)
- Utilities (electric, natural gas, water, telecommunications)
- Academia (public and private research and education institutions, schools, colleges, and universities)
- National laboratories
- Public agencies (local, state, and federal)
- Professional and business associations / organizations
- End user (public)
- Non-profit (Natural Resources Defense Council [NRDC], Sierra Club)

Combined heat and power systems have been a key research focus area for the PIER AG program over the years.

Examples of PIER AG Research Projects Completed in 2008

- **Partial-oxidation gas turbine (POGT)**. An innovative technology that shows promise for unusually high efficiency power generation in industrial heat and power systems applications. The Gas Technology Institute demonstrated the technical feasibility of modifying a 200-kW gas turbine to a POGT system. Ten percent of the fuel energy is converted in the POGT to heat for electricity generation. The remaining 90 percent is converted to a hot hydrogen-containing synthesis gas plus steam, suitable for low nitrogen oxide (NOx), low carbon monoxide combustion or as a hydrogen source.
- **Ultra-clean microturbine boiler with the boiler adapted for a CHP package.** The benefits to California include: ultra-clean technology (California Air Resources Board DG 2007 Compliant); energy-efficient (CHP efficiency is approximately 80 percent); economical CHP Package (payback period is two to three years); significant criteria pollutant and greenhouse gas emission reductions; and very large commercialization potential.
- **The 100-kW CHP system integrated with inverter technology providing grid-independent variable speed operation.** The benefits for this system include: standardized interconnection, variable speed operation for a higher base load, meeting 2007 emission limits with CHP.

Advanced electric generation will continue to be a significant element of California's energy system. Generation using non-renewable resources is very likely to continue for the foreseeable future and will remain a significant player in the generation mix. Further, advanced clean and low-emission non-renewable generation technologies are essential for the environment and survival of plants and animals. Lastly, if natural gas (NG) is to last for 100 years at the current rate of consumption (and efficiency), developing higher efficiency NG engine/turbine/fuel cell/boilers and CHP technology could extend it to meet energy needs for 150 years.

1.3. Strategic Opportunity for PIER Advanced Generation

Investing in advanced generation technology provides an opportunity for developing reliable, affordable, secure, and sustainable power. Accelerating the replacement of inefficient power plants and expanding the advanced power generation development program to expand the baseload generation capacity to meet customer needs would further improve the environmental quality of the power generation sector in California. While California's power generation has a strong record of environmental performance, performance could be improved through new, cleaner generation supplies to simultaneously meet growing demand while displacing less environmentally advanced units and improving reliability while improving environmental performance concurrently. Investments in CO2 capture technology are needed so that the technology is available in the future. Investing in the next generation of technology to ensure that customers have access to the latest, most advanced technologies is a critical part of the advanced power generation initiative. This should ultimately lead to commercialization of the next generation of even cleaner generation technologies and to pursue advancement of next generation technologies through collaborations and partnerships with research and development (R&D) and power generation entities.

1.4. Advanced Generation Roadmap Development Process

The PIER Advanced Generation Program is looking to support specific state policy goals for electricity generation.

A prerequisite to this effort is to develop a long-term roadmap that is intended to guide PIER Advanced Generation RD&D efforts.

The approach to the roadmapping process is outlined in Figure 2.

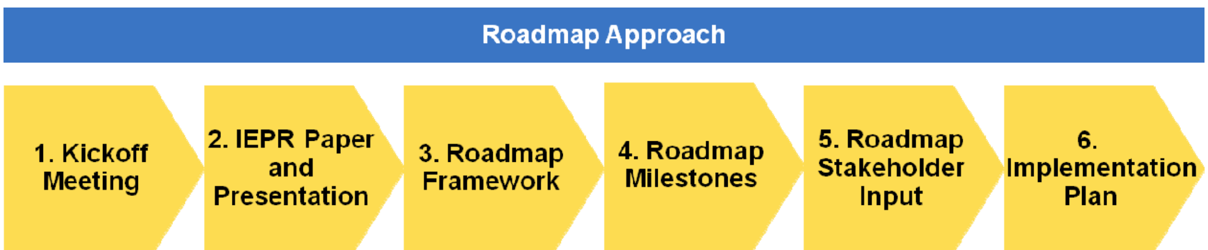

Figure 2. PIER Advanced Generation Roadmap Approach
Source: Navigant Consulting, Inc.

1.5. Objective of Background Paper

This paper will help the reader understand the current status of advanced generation technologies and identify key areas for RD&D investments. In particular, this paper will:

- Identify and review the policy framework that will guide the PIER Advanced Generation Program.
- Indentify and review the current status and key issues or barriers, challenges, and opportunities for developing and integrating clean and advanced generation options into the California electricity supply system.
- Highlight what other organizations/institutions are doing to address these issues, including entities such as the United States Department of Energy, other countries, universities, leading U.S. utilities, and the private sector.
- Support policymaking by presenting the background paper in workshop proceedings for the *2009 Integrated Energy Policy Report*.
- Define the strategic framework (for example, vision, target research areas, and key research needs) for the PIER AG roadmap.

2.0 Policy Framework

The PIER program is charged with conducting RD&D activities consistent with state and federal energy policy priorities as defined by executive orders, state legislation, and articulated goals in the Energy Commission's *IEPRs*.

The following section identifies the state energy policy directives and goals that guide the prioritization of RD&D activities that focus on advanced generation technologies.

2.1. California Advanced Generation Energy Policy

California goals focus largely on reducing emissions and environmental impacts from electricity generation. Major policy goals are:

Natural Gas Power Plant Goals

- By 2012, repower aging power plants or retire and replace with cleaner technologies (*IEPRs*).

Distributed Generation/CHP Goals

- Use CHP so that new construction can achieve net zero energy by 2020 for residences and 2030 for commercial (*2007 IEPR*).
- Install 4,000 MW of additional CHP capacity by 2020 (ARB *AB 32 Scoping Plan*)

Water Use for Generation Goals

- Phased elimination of once-through cooling between 2015 and 2021 (*2008 IEPR*)

Greenhouse Gas Goals

- Greenhouse gas emissions targets are to reduce GHG emissions:
    - To 2000 levels by 2010.
    - To 1990 levels by 2020.
    - To 80 percent below 1990 levels by 2050 (Governor's Executive Order).
- Statewide greenhouse gas emissions are planned to be limited to 1990-equivalent levels by 2020 (AB 32).

Many state policy documents issue policy directives, rather than specific target goals. In these directives, the state recognizes the importance of power plant efficiency, of capturing carbon, and of CHP. Key state policy directives are:

Natural Gas Power Plant Directives

- Increase natural gas research and development for ways to advance energy efficiency for power plants (*2007 IEPR*)

- California may be better off repowering plants that are locationally critical to the state's electricity system (*2005 IEPR*)
- Even with energy efficiency, demand response, and renewable resources, investments in conventional power plants are still likely to be needed (*Energy Action Plan [EAP] 2008 Update*)
- SB 1368 prevents new reliance on power plants with CO2 emissions greater than 1,100 pounds per MWh, similar to those of a modern natural gas combined cycle power plant (*2007 IEPR*, SB 1368)
- Over the last decade, between 29 percent and 42 percent of California's in-state generation used natural gas. Because natural gas is becoming more expensive, and because much of electricity demand growth is expected to be met by increases in natural gas-fired generation, reducing consumption of electricity and diversifying electricity generation resources are significant elements of plans to reduce natural gas demand and lower consumers' bills (*EAP I and II*).

Carbon Capture and Sequestration Directives

- California's efforts may consider focusing on longer-term research and development on advanced concepts for IGCC, USC PC (ultra-supercritical pulverized coal), and SC CFBC (supercritical circulating fluidized bed combustion) plants—including integration of CO2 capture systems—for plants coming on-line after 2015-2020 (*2005 IEPR*).
- To meet long-term greenhouse gas goals, California will need the development of…clean fossil generation, including carbon capture and sequestration (*2005 IEPR*, *EAP 2008 Update*).
- In response to a lower cap on emissions, existing coal generation contracts would not be renewed, or carbon capture and storage would be utilized to minimize emissions. The remaining electricity generation would come from natural gas combustion either in cogeneration applications or from highly efficient generating units (ARB *AB 32 Scoping Plan*).

Distributed Generation/CHP Directives

- Develop CHP regulations for system size, efficiency standards, cost-effectiveness, technical feasibility, and environmental benefits by January 1, 2010 (*2008 IEPR Update*, Assembly Bill 1613 [Blakeslee, Chapter 713, Statutes of 2007]).
- Combined heat and power facilities must provide a larger role in meeting California's electricity supply needs (*2007 IEPR*).
- California's current energy efficiency programs should provide models and strategies which will support CHP development and goals (*2008 IEPR Update*).
- Promote clean, small generation resources located at load centers (*EAP I*).

Water Use for Generation Directives

- Increase the use of best available retrofit technologies such as large organism exclusion devices and modern screens at existing coastal power plants to minimize the impacts of using of ocean water for once-through cooling of fossil power plants (*2008 IEPR Update*).
- Recycled water can substitute for fresh water for power plant cooling (*2005 IEPR*).

Other Directives

- The loading order to meet energy needs is as follows:
    1. Energy efficiency.
    2. Renewable energy and distributed generation.
    3. Clean fossil-fueled sources (*EAP I*).
- New nuclear plants cannot be relied on, at least in the near term, to meet California's AB 32 GHG emissions reduction goals for 2020 (*2008 IEPR Update*).
- No nuclear power plant shall be a permitted land use in the state until there exists a means for the disposal of nuclear waste (Public Resources Code 25524.2).
- Ensure that the citizens of this state continue to receive safe, reliable, affordable, and environmentally sustainable electric service (Senate Bill 1250 [Perata, Chapter 512, Statutes of 2006]).
- Ensure that power plant siting will not disproportionately affect minority and low-income communities (PIER Overview of Environmental Justices Requirements).

State Policy Takeaways

To meet AB 32 requirements and other state policy goals, PIER AG must work within a policy framework that lacks specific targets. Though the state's primary source of generation comes from natural gas, there are no specific goals for natural gas power plant efficiency, even though they are implied through generation emissions standards. Further, policy indicates that the state is interested in carbon capture and sequestration research, but it has not developed specific targets or goals. Many of the policy goals and directives address the importance of combined heat and power, including some policy surrounding other types of distributed generation. Additionally, the current goal to eliminate once-through cooling between 2015 and 2021 is still being addressed by the State Water Resources Control Board. Policy makers are also discussing how to revise the goal to retire or repower aging plants by 2012 because it is not likely to be achieved. Lastly, advanced generation would make a great contribution to helping the state move to higher levels of renewable energy (33 percent by 2020, with additional renewables likely to be needed to meet the Governor's goal of 80 percent reduction in GHG emissions from 1990 levels by 2050) through gas-fired (and/or biomass/biogas fired) advanced generation with the operational flexibility characteristics to address the intermittency of renewables.

2.2. Federal Advanced Generation Energy Policy

The following pieces of federal legislation provide the bulk of the key federal policy directives and goals related to advanced generation[3]:

- Energy Policy Act of 2005
- Energy Independence and Security Act of 2007
- Energy Improvement and Extension Act of 2008
- American Recovery and Reinvestment Act of 2009
- Clean Water Act, Section 316(b)

While these federal incentives and policy directives are important, the State of California still leads the nation in most of these issues in terms of implementation and execution. Therefore, the federal policies are currently seen as enhancing California policy instead of superseding it. Key federal policy goals are:

Fossil Fuel Generation Goals:

- The 2005 Energy Policy Act sets a goal that by 2020, coal gasification projects shall be able to:
    - Remove at least 99 percent of sulfur dioxide
    - Emit not more than .05 lbs of NOx per million British thermal unit (Btu)
    - Achieve at least 95 percent reductions in mercury emissions
    - Achieve a thermal efficiency of at least
        - 50 percent for coal of > 9,000 Btu
        - 48 percent for coal of 7,000 - 9,000 Btu
        - 46 percent for coal of < 7,000 Btu

Distributed Generation/CHP Goals

- The 2005 Energy Policy Act calls for a commitment not later than 2015 that will lead to infrastructure by 2020 that will provide:
    - Hydrogen for fuel cells, internal combustion engines, and other energy conversion devices for portable, stationary, micro, critical needs facilities, and transportation applications.

In federal policy directives, due to the country's heavy reliance on coal for power production, Carbon capture and sequestration is given the most focus. Key federal policy directives are:

[3] For additional details see Appendix 7.1.

Natural Gas Power Plant Directives:

- Conduct a program of research, development, demonstration, and commercial application on:
    - Efficiency and reliability of gas turbines for power generation.
    - Reduction in emissions from power generation (Energy Policy Act).

Carbon Capture and Sequestration Directives:

- Carry out a 10-year carbon capture research and development program to develop carbon dioxide capture technologies on combustion-based systems for use in new coal utilization facilities and on the fleet of coal-based units in existence (Energy Policy Act).
- Provide loan guarantees for advanced generation projects, including integrated gasification combined cycle technology, that offer the potential to sequester carbon dioxide emissions and provide a ready source of hydrogen for near-site fuel cell demonstrations (Energy Policy Act).
- Promote regional carbon sequestration partnerships to conduct geologic sequestration tests involving carbon dioxide injection and monitoring, mitigation, and verification operations in a variety of candidate geologic settings (Energy Independence and Security Act).
- The 2009 Stimulus Package funds carbon capture and sequestration research outlined in the Energy Independence and Security Act of 2007 (American Recovery and Reinvestment Act of 2009).

Water Use for Generation Directives:

- Carry out a program of research, development, demonstration, and commercial application to address energy-related issues associated with provision of adequate water supplies, optimal management, and efficient use of water (Energy Policy Act).
- Include arsenic treatment, desalination and planning, analysis, and modeling of energy and water supply and demand (Energy Policy Act).
- The location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. (Clean Water Act).

Other Directives:

- Conduct programs to address use of hydrogen for commercial, industrial, and residential electric power generation (Energy Policy Act).

Federal Policy Takeaways

- The federal government has devoted a considerable amount of attention to carbon capture and sequestration efforts. Examples include:

- *Clean Coal Power Initiative* funds new coal technologies that can help utilities cut greenhouse gas emissions as well as sulfur, nitrogen, and mercury pollutants from power plants. Since January 2003, 12 projects have been selected for funding. A third-round solicitation is underway focused on carbon sequestration technologies and/or beneficial reuse of carbon dioxide. These proposals are under review. The American Recovery and Reinvestment Act of 2009 provided an additional $800 million.
- *FutureGen,* a $1 billion Department of Energy initiative to demonstrate cutting-edge carbon capture and sequestration (CCS) technology at multiple commercial-scale integrated gasification combined-cycle (IGCC) or advanced coal power plants. Under this approach, multiple commercial plants would each produce at least 300 megawatts of electricity and sequester at least 1 million metric tons of carbon dioxide each year. US DOE released a Funding Opportunity Announcement (FOA) on June 24, 2008, with a deadline of October 8, 2008. The project was cancelled later in 2008 and has recently been reinstated with ARRA funding.

• Resources have been allocated for research in advanced distributed generation, including micro CHP and hydrogen fuel cells.

• As part of the ARRA, US DOE was appropriated more than $38 billion, from which $3.4 billion is related to advanced generation.[4] Here is the breakdown of the appropriations:

• ***American Recovery and Reinvestment Act of 2009 — Department of Energy Appropriation***

  - Energy Efficiency and Renewable Energy will receive nearly $17 billion to support various programs such as improving the energy efficiency of low-income housing, conducting energy research and development projects, and studying alternative fuels for vehicles.
  - Chief Financial Officer will be provided with $6 billion as part of its loan program for new or significantly improved energy production technologies that avoid, reduce, or sequester air pollutants and other greenhouse gases.
  - Environmental Management has been authorized nearly $6 billion to clean up environmental contamination resulting from Cold War manufacturing activities.
  - Electricity Delivery and Energy Reliability will have $4.5 billion available, most of which is dedicated to support modernization of the Nation's electrical grid.
  - Fossil Energy will receive $3.4 billion to support research and development activities such as carbon capture and storage.

[4] Source: Department of Energy Fossil Energy program website, Department of Energy press release from May 15, 2009.

- Science is expected to be provided with $1.6 billion to further enhance ongoing research efforts.

- Of the $3.4 billion advanced generation funding, $1 billion is for R&D while the rest will help accelerate deployment of carbon capture and storage technology

    - **Fossil Energy R&D**: $1.0 billion for fossil energy research and development programs. Details to be defined.

    - **Clean Coal Power Initiative:** $800 million will be used to expand US DOE's Clean Coal Power Initiative, which provides government co-financing for new coal technologies that can help utilities cut sulfur, nitrogen, and mercury pollutants from power plants. The new funding will allow researchers broader CCS commercial-scale experience by expanding the range of technologies, applications, fuels, and geologic formations that are tested.

    - **Industrial Carbon Capture and Storage:** $1.52 billion will be used for a two-part competitive solicitation for large-scale CCS from industrial sources. The industrial sources include, but are not limited to, cement plants, chemical plants, refineries, steel and aluminum plants, manufacturing facilities, and petroleum coke-fired, and other power plants. The second part of the solicitation will include innovative concepts for beneficial CO_2 reuse (CO_2 mineralization, algae production, etc.) and CO_2 capture from the atmosphere. In addition, two existing industrial and innovative reuse projects, previously selected via competitive solicitations, will be expanded to accelerate scale-up and field testing:

    - **Ramgen Modification ($20 million)**: Funding will allow the industrial-sized scale-up and testing of an existing advanced CO_2 compression project with the objective of reducing time to commercialization, technology risk, and cost. Work on this project will be done in Bellevue, Washington.

    - **Arizona Public Services Modification ($70.6 million)**: Funding will permit the existing algae-based carbon mitigation project to expand testing with a coal-based gasification system. The goal is to produce fuels from domestic resources while reducing atmospheric CO_2 emissions. The overall process will minimize production of carbon dioxide in the gasification process to produce a substitute natural gas (SNG) from coal. The host facility for this project is the Cholla Power Plant located in Holbrook, Arizona.

    - **Geologic Sequestration Site Characterization:** $50 million will fund a competitive solicitation to characterize a minimum of 10 geologic formations throughout the United States. Projects will be required to complement and build upon the existing characterization base created by US DOE's Regional Carbon Sequestration Partnerships, looking at broadening the range and extent of geologic basins which have been studied to date. The goal of this effort is to accelerate the determination of potential geologic storage sites.

- **Geologic Sequestration Training and Research:** \$20 million will be used to educate and train a future generation of geologists, scientists, and engineers with skills and competencies in geology, geophysics, geomechanics, geochemistry and reservoir engineering disciplines needed to staff a broad national CCS program. This program will emphasize advancing educational opportunities across a broad range of minority colleges and universities and will use US DOE's University Coal Research Program as the model for implementing the program.

3.0 Technology Profiles

This paper covers 20 primary focus technology areas organized into 5 groups, as well as 6 secondary focus technology areas, organized into 3 groups, shown in Table 2. The primary focus technologies directly pertain to PIER AG. The secondary focus technologies are mainly addressed by other PIER research areas. However, AG is participating in the research and coordination of the secondary focus technologies and is providing its support.

Table 2. Technologies Profiled

Primary Focus Technologies	*Secondary Focus Technologies*
• Distributed Generation/Combined Heat and Power -Fuel Cells -Hybrid Fuel Cell Gas Turbine Cycles -Reciprocating Engines -Stirling Engines -Microturbines -Gas Turbines • Cooling -Absorption Chillers • Advanced Gas Turbine Cycles -Industrial Cogeneration -Inlet Cooling -Recuperation -Intercooled/recuperated -Heat recovery -Advanced Simple Cycle for Peaking -Hybrid Renewable Cycles -Integrated Gasification Simple Cycle • Replacement for Once-Through Cooling -Dry Cooling -Wet Cooling Towers -Alternative Cooling Water -Hybrid Cooling Towers • Carbon Reduction -Pre-Combustion Capture	• Advanced Coal/Biomass Combustion -Integrated Gasification Combined Cycle -Ultra-Supercritical Pulverized-Coal -Supercritical Circulating Fluidized-Bed Combustion • Carbon Capture and Sequestration -Post-Combustion Capture -Geological Sequestration • Advanced Nuclear Power Generation - Advanced Boiling Water Reactor (ABWR) Advanced Pressurized Water Reactor (APWR)

Source: Navigant Consulting, Inc.

3.1. Primary Focus Technologies

3.1.1. Distributed Generation/CHP

All of the distributed generation technologies covered in this report are used in combined heat and power applications, as shown in Figure 3.

		Typical Applications			
		CHP / CCHP	Baseload	Backup / DR / Peak Shaving	Cycling
Technologies	Fuel Cells	✓	✓	✓	✗
	Hybrid Fuel Cell Gas Turbine Cycles	✓	✓	✓	✗
	Reciprocating Engines	✓	✓	✓	✓
	Stirling Engines	✓	✓	✗	✗
	Microturbines	✓	✗	✗	✓
	Gas Turbines	✓	✓	✓	✓

Figure 3. Technologies Used in CHP Applications

Source: Navigant Consulting, Inc.

Key takeaways from profiles of distributed generation/CHP technologies are:

- Cost is still a limiting factor for widescale adoption of most distributed generation technologies.
- Combined heat and power is typically the most cost-effective application for distributed generation.
- There is a recent trend in research on fuel flexibility of DG/CHP systems, specifically targeting alternative fuels and other low-value fuels
- There is limited investment in communication and control technologies for distributed generation systems.
- Rule 21 has been successful in removing interconnection barriers.
- Hybrid fuel cell gas turbine cycle systems have some of the highest efficiencies among distributed generation technologies.

- A large amount of funding is going to transportation fuel cells, with limited research funding going to stationary power fuel cells.
- As transportation technology research becomes more focused on plug-in hybrid technologies and moves away from fuel cells, this could also lead to reduced funding for stationary fuel cell research.
- PIER and the Electricity Analysis Office are funding an industrial CHP market potential study, as well as an update to the 2005 CHP market potential study.

Distributed Generation/CHP Incentives

There are many federal and state incentives in place for distributed generation, including combined heat and power applications. Some publicly owned utilities (POUs) also offer incentives for distributed generation and combined heat and power, as well.

Federal Incentives

- The Federal Business Energy Investment Tax Credit (ITC) gives a tax credit for fuel cells with a minimum capacity of 0.5 kW, for microturbines up to 2 MW, and for CHP less than 50 MW. The fuel cell credit is capped at $1,500 per 0.5 kW, the microturbine credit is capped at $200 per kW of capacity, and the CHP credit is 10 percent of expenditures, with no maximum limit stated (DG1).
- Energy Efficient Commercial Buildings Tax Deduction gives $0.30-$1.80 per square foot for CHP/cogeneration technologies, depending on technology and amount of energy reduction (DG1).
- Under the federal Modified Accelerated Cost-Recovery System (MACRS), businesses may recover investments in fuel cells, microturbines, and CHP in certain property through depreciation deductions (DG1).
- CHP Investment Tax is a 10 percent tax credit for the first 15 MW of a system up to 50 MW. Eligible technologies are combustion turbines, fuel cells, microturbines, reciprocating engines, heat recovery generators, and Stirling engines (DG3).
- Qualifying Advanced Energy Project Investment Tax Credit–30 percent of the qualified investment required for an advanced energy project, including microturbines and fuel cells (DG1).

State Incentives

- Self Generation Incentive Program–administered by the state's IOUs, the program awards funding to eligible technologies, which include only wind turbines and renewable and nonrenewable fuel cells, including nonrenewable fuel cell CHP systems (DG2).
- Energy Efficiency Financing Program–The California Energy Commission will provide up to $26 million in loans to schools, hospitals, and local governments for the

installation of energy-saving measures or for energy audits and studies. Interest rates are fixed at 3.95 percent for the term of the loan. The maximum loan amount is $3 million, and there is no minimum loan. Eligible technologies are CHP/cogeneration, and other DG technologies (DG1).

- CHP systems meeting minimum thermal use and efficiency standards receive an incentive gas price based on the electric generation rate (DG4).

POU Incentives

- City of Palo Alto Utilities offers a DG incentive program, called PLUG-In. PLUG-In program incentives will be available to support up to 20 MW of CHP, or $5 million over 10 years. The program incentive funds are to be collected through electric rates as part of customer commodity charges. Eligible technologies under the PLUG-In program include CHP, fuel cells, waste heat recovery, and renewable resources. The program allows a maximum size of 10 MW per customer served for a single system. If small gas turbines or reciprocating engines are selected as the generating technologies, the base incentive is $500/kW for the first MW and $250/kW for the second MW resulting in a maximum base incentive of $750,000. If microturbines are used, the incentive is $700/kW for the first MW and $250/kW for the second MW resulting in a maximum base incentive of $900,000. There is a bonus incentive of $50/kW available for CHP systems that receive an ENERGY STAR® CHP Award (DG2).
- Anaheim Public Utilities has a low-interest energy efficiency loan program that grants up to $350,000 or 10 times the projected annual savings for CHP/cogeneration and heat recovery. The loan is fixed at 5 percent interest rate over 8 years (DG1).

Fuel Cells – Overview

Fuel cells are one of the least problematic DG technologies to site owing to their quiet operation, low emissions, high efficiencies, and modular design. A large amount of funding is going to transportation fuel cells, with limited research funding going to stationary power fuel cells. As transportation technology research becomes more focused on plug-in hybrid technologies and moves away from fuel cells, this will lead to reduced funding for stationary fuel cell research. In addition to the technical barriers and research gaps, other major barriers facing fuel cells include low production volume and capacity and high capital costs. Major research is needed in increasing fuel flexibility, improving reliability, increasing stack life, improving fuel reformer design, reducing size and system complexity, and developing low-cost material alternatives. Further, high temperature fuel cells offer higher efficiencies, larger capacities, better fuel flexibility potential, larger capacities, and better CHP opportunities than low-temperature fuel cells; however, they receive less funding and are a less mature technology than low-temperature fuel cells.

Fuel Cells – Description

A fuel cell is an electrochemical device that combines chemical fuels (hydrogen or carbon monoxide) and oxygen to produce electricity, with heat, water, and/or carbon dioxide as its by-product. Unlike a battery however, which has a finite amount of stored energy, as long as fuel is supplied the fuel cell will continue to generate power. Since the conversion of the fuel to energy takes place via an electrochemical process, not combustion, the process is clean, quiet and highly efficient (FC2). Fuel cells are differentiated based on the type of electrolyte used and their operating temperatures.

Low-temperature fuel cells, such as proton exchange membrane (PEM) and phosphoric acid (PA), can use only hydrogen as a fuel. The fuel must be of high purity because it is susceptible to CO and sulfur poisoning. High-temperature fuel cells also use hydrogen as a fuel, but because of their high temperatures and resistance to CO poisoning, they can also use CO, and hydrocarbon fuels as internal reforming is possible. All fuels must be desulfurized before use however.

Currently, fuel cells can achieve system efficiencies of 35 percent-45 percent higher heating value (HHV) and up to 80 percent (HHV) system efficiency in CHP applications (FC:2,8) with projected efficiencies of up to 60 percent (HHV) (FC9).

Fuel cells differ based on the type of electrolyte used and their operating temperatures. The four most prominent types of fuel cells are:

- **Proton Exchange Membrane Fuel Cells (PEMFC)** – PEMFCs use a polymeric membrane as their electrolyte and operate at relatively low temperatures of 150-180°F.
- **Phosphoric Acid Fuel Cells (PAFC)** – PAFCs use liquid phosphoric acid as the electrolyte and operate at temperatures of 320-410°F.
- **Molten Carbonate Fuel Cells (MCFC)** – MCFCs use an electrolyte composed of a molten carbonate salt mixture suspended in a porous, chemically inert matrix and operate at high temperatures of 1200-1300°F.(FC:2,8)
- **Solid Oxide Fuel Cells (SOFC)** – SOFCs use a hard, non-porous ceramic compound as the electrolyte and operate at very high temperatures of 1350-1850°F.(FC:2,7,8)

PEM fuel cells have been widely considered to be the most attractive fuel cell technology for residential applications. Table 3 below lists key characteristics of PEMFCs.

Table 3. Fuel Cell Sub-Technology Characterization – PEMFC

Sub-Technology Characterization – PEMFC	
Description	**Size** – 100W-500kW Units (FC:8,9) **Fuel** – The catalyst is most susceptible to CO poisoning and therefore can only utilize very high purity hydrogen, this limits the sources for fuel (FC7). To use fuel feedstock such as natural gas and propane an external fuel reforming subsystem must also be installed. **Efficiency** – They exhibit system efficiencies of 25-35 percent (HHV) and up to 65 percent (HHV) in CHP(FC:8,31) and have projected efficiencies of approximately 40 percent (HHV).(FC:9,30) **Applications** – This technology is in the development stage(none commercially available) for microCHP applications (FC1). The potential applications of PEMFC (besides transportation) include residential and small commercial CHP(FC8), premium power applications, and small peaking generators in retail markets (FC:7,8,11). The markets for the small CHP applications and remote power open up significantly when installed costs reach $1000/kW (FC7).
Cost	**Total Installed Cost** • Current = 4,000-9,100 $/kW (FC:8,9,11) • Target = 1,000 $/kW for a continuously operating unit(FC7,11) and 500 $/kW for a peaking unit.(FC7) **Operating and Maintenance (O&M) Cost[5]:** 0.015-0.035 $/kWh (FC:2,38) **Total Levelized Cost:** 0.11-0.17 $/kWh (FC38)
Emissions	**CO_2[6]:** 1200-1400 lb/MWh (non CHP operation) depending on the electrical efficiency of the fuel cell. (FC:2, 8) **Criteria Pollutants:** No SOx emissions, NOx, CO, and VOC emissions are negligibly low (0.01-0.07 lb/MWh).(FC8)
Benefits	**Application Flexibility** – High power density, modularity, quick start-up time, and the ability to quickly meet shifts in power demand make this a dynamic generating technology capable of accommodate a high degree of load cycling. These attributes combined with its modularity allow the PEM to be used in a variety of applications (FC:1,2,8,9). **Ease of Siting** – As a result of their quiet operation and low emissions siting issues for fuels cells are possibly the least problematic of all DG technologies.(FC9) **Energy Savings** – Fuel cells exhibit high system efficiencies over broad load profiles especially if they are used in CHP applications.(FC:8,9) **Low Emissions** – All fuel cells exhibit negligible criteria emissions and very low CO2 emissions if “clean” fuels such as NG or renewable sources are used to generate the fuel cell hydrogen.(FC:8,9) **End-user Reliability** – The fixed dimension and low acidity of the membrane electrolyte simplifies the sealing and production process and contributes to future potential cell and stack longevity.(FC:7) **Low Capital Costs** – The modularity and potential for simple manufacturing contributes to future potential for low production costs.(FC:8) **Low Water Usage** – PEMFCs do require very little water to operate or cool. (FC37)
Potential	The initial market envisioned for PEMFCs is the transportation sector and the residential and small commercial sectors.

Source: Navigant Consulting, Inc.

[5] Excludes the cost of stack replacement. Stack lives are typically 10-20k (FC2) hours and cost >$1,000/kW to replace (FC27).

[6] Emissions values assume a fuel reforming subsystem using natural gas with a 34lb/MMBtu carbon content.

Phosphoric acid fuel cells are the most robust and proven fuel cells in the market, with over 300 systems delivered by UTC and Fuji. Table 4 below lists key characteristics of PAFCs.

Table 4. Fuel Cell Sub-Technology Characterization – PAFC

Sub-Technology Characterization – PAFC	
Description	**Size** – 50-200kW with plants up to 5MW(FC:7-9) **Fuel** – These cells can only be fueled with high quality hydrogen. The catalyst is less susceptible to poisoning from CO than PEMFCs, they can tolerate CO concentrations of about 1.5 percent in the fuel (FC2). In order to use fuel feedstock such as natural gas and propane an external fuel reforming subsystem must also be installed. **Efficiency** – They exhibit system efficiencies of 33-37 percent (HHV) and approximately 80 percent (HHV) in CHP. (FC:2,8,34) **Applications** – This technology is in commercial growth stage with over 75 MW of capacity installed over the last 10 years and over 8 million operating hours.(FC8) The potential applications for PAFCs include small and normal sized commercial CHP, especially those applications which require high power reliability and availability such as hospitals, hotels, nursing homes, schools, and office buildings.(FC:2,7,11)
Cost	**Total Installed Cost** • Current = 3000-6300 $/kWh (FC:2,7-9,27) • Target = 1300-1500 $/kW (FC:7,27) **O&M Cost[7]:** 0.008-0.038 $/kWh (FC:2,8,27,38) **Total Levelized Cost:** 0.10-0.15 $/kWh (FC38)
Emissions	**CO2[8]:** 1150-1300 lb/MWh (non-CHP operation) depending on the electrical efficiency of the fuel cell.(FC:2, 8) **Criteria Pollutants:** No SOx emissions, NOx, CO, and VOC emissions are negligibly low (0.01-0.04lb/MWh).(FC8)
Benefits	**End-user Reliability** – Most commercially proven fuel cell technology, proven stack life of 40,000 hours, reliability of 90-95 percent, availability of over 90 percent,(FC8) and tested continuous use of 5,500 hours which is comparable to other power plants.(FC9) **Low Emissions** – PAFCs have been exempted from air quality permits in some of the strictest districts in the country including districts in the Los Angeles basin.(FC9) **Fuel Diversity** – PAFCs can use impure hydrogen since they can tolerate CO levels of up to 1.5 percent. This broadens the choice of fuels which can be fed into the reformer system compared to the PEMFC.(FC2) **Ease of Siting** – As a result of their quiet operation and low emissions siting issues for fuels cells are possibly the least problematic of all DG technologies.(FC9) **Energy Savings** – Fuel cells exhibit high system efficiencies over broad load profiles especially if they are used in CHP applications.(FC:8,9)
Potential	The market for PAFC is small and normal sized commercial CHP applications, especially those applications which require high power reliability and availability.

Source: Navigant Consulting, Inc.

[7] Includes the cost of stack replacement every 7.5 years.

[8] Emissions values assume a fuel reforming subsystem using natural gas with a carbon content of 34 lb/MMBtu.

Molten carbonate fuel cells are considered the most advanced commercially available fuel cell technology and have the highest potential efficiency. Table 5 below lists key characteristics of MCFCs.

Table 5. Fuel Cell Sub-Technology Characterization – MCFC

Sub-Technology Characterization – MCFC	
Description	**Size** – 300kW-2MW (FC:2,8) with projected applications in the 1-20MW range (FC:7,9) **Fuel** – These fuel cells can operate not only on hydrogen, but can also operate on carbon monoxide, natural gas, propane, landfill gas, marine diesel, and simulated coal gasification products without the need for an external reformer subsystem.(FC2) This is because the high temperatures allow for internal reforming and the fuel cell isn't susceptible to CO poisoning. **Efficiency** – These cells exhibit system efficiencies of 40-46 percent (HHV) and approximately 70 percent (HHV) in CHP (FC:8,33) **Applications** –Technology in commercial introduction stage with 300 and 1,200 kW systems recently offered and installed in a number of CHP applications.(FC8) The potential applications for MCFCs include larger industrial base loading applications (1-20 MW), especially where opportunities for CHP and combined cycle generation exist. (FC:1,7,9,11) Opportunities also exist for electric utility applications.(FC2)
Cost	**Total Installed Cost -** Current = 3,000-5,580 $/kW (FC:7,8,27,38) Target = 1,200-1,500 $/kW (FC:7,11,27) **O&M Cost[9]:** 0.025-0.055 $/kWh (FC:1, 8,27,38) **Total Levelized Cost:** 0.085-0.12 $/kWh(FC38)
Emissions	**CO2[10]:** 920-1060 lb/MWh (non CHP operation) depending on the electrical efficiency of the fuel cell.(FC:2, 8) **Criteria Pollutants:** No SOx emissions; NOx, CO, VOC emissions negligible as result of the reforming temperature (0.01-0.10 lb/MWh) (FC8)
Benefits	**Energy savings** – MCFCs have the highest efficiency of all fuel cell technologies and therefore have the potential for the most significant energy savings.(FC:7,9) **Application flexibility** – The modularity, which allows for easy expansion of plants, and high operating temperature, which makes the technology attractive for cogeneration applications, allow this fuel cell to be suited for a variety of applications. **Fuel Diversity** – Because they are relevantly tolerant of fuel impurities (not susceptible to CO poisoning) and internal reforming is possible, the fuel choices for this technology are broad, especially when compared to the PEMFC and PAFC.(FC:8,9) They can compete directly with IC engines and gas turbines in this regard. **Low Capital Costs** – Because effective metals such as nickel, as opposed to platinum, are used in the electrodes, future productions costs may be lower than PAFCs and PEMFCs. **Ease of Siting** – Given quiet operation and low emissions, siting issues for fuels cells are the least problematic of DG technologies.(FC9) **Low Emissions** – All fuel cells exhibit negligible criteria emissions and very low CO2 emissions if "clean" fuels such as NG or renewable sources are used to generate the fuel cell hydrogen.(FC:8,9) **End-user Reliability** – Fuel cells are expected to exhibit higher reliability and availability than gas turbines because they have fewer moving parts in their design, this can contribute to high reliability in the future.(FC9)
Potential	Because of their larger size the target market for MCFCs include the industrial and large commercial sector.

Source: Navigant Consulting, Inc.

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[9] Includes the cost of stack replacement every 3-5 years.

[10] Emissions values assume a fuel reforming subsystem using natural gas.

Solid oxide fuel cells are believed to have the potential to span the widest range of market applications. Table 6 below lists key characteristics of SOFCs.

Table 6. Fuel Cell Sub-Technology Characterization – SOFC

Sub-Technology Characterization – SOFC	
Description	**Size** – 2kW-300kW (FC:7,11) with the potential for wholesale DG units of 10-25MW (FC7) **Fuel** –Due to its resistance to CO poisoning and high operating temperatures, allowing these cells to utilize internal reformer technology, they can directly accept fuels such as natural gas, biogas, ethanol, methanol, carbon monoxide, and syngas in addition to hydrogen. (FC:7-9). **Efficiency** – These cells exhibit system efficiencies of 40-46 percent (HHV) and approximately 70 percent (HHV) in CHP (FC:8,33) **Applications** – This technology is in the development stage with several companies around the world working on pre-commercial demonstration units.(FC:2,7,37) It is believed to be the only FC technology that has the potential to span market applications ranging from small residential to wholesale DG power generation.(FC7) Applications for utility grid support and industrial on-site generation, supplying base loads while taking advantage of CHP and combined cycle generation opportunities.(FC:7,9,11)
Cost	**Total Installed Cost -** Current = 3,000-5,000 $/kW(FC:27,38) Target = 1,000-2,000$/kW (FC:7,9,11,27) **O&M Cost:** 0.024 $/kWh(FC38) **Total Levelized Cost:** 0.068-0.10 $/kWh(FC38)
Emissions	**CO2[11]:** 950-1060 lb/MWh depending on the electrical efficiency of the fuel cell.(FC:2,8) **Criteria Pollutants:** No SOx emissions, NOx, CO, and VOC emissions are negligibly low as a result of the reforming temperature (0.01-0.05 lb/MWh) (FC8)
Benefits	**End-user Reliability** – High potential for stability and reliability due to solid-state construction.(FC:7-9) **Application flexibility** – The modularity, which allows for easy expansion of plants, and high operating temperature, which makes the technology attractive for cogeneration applications, allow this fuel cell to be suited for a variety of applications. **Energy Savings** – Higher efficiency than PAFCs and PEMFCs, therefore these fuel cells will yield more significant energy savings. **Fuel Diversity** – Because they are relevantly tolerant of fuel impurities (not susceptible to CO poisoning) and internal reforming is possible, the fuel choices for this technology are broad, especially when compared to the PEMFC and PAFC.(FC:8,9) They can compete directly with IC engines and gas turbines in this regard. **Low Capital Costs** – Because effective metals such as nickel, as opposed to platinum, are used in the electrodes, future productions costs may be lower than PAFCs and PEMFCs.(FC7) **Low Water Usage** – SOFCs require very little water to operate or cool. (FC37) **Ease of Siting** – Given quiet operation and low emissions, siting issues for fuels cells are the least problematic of all DG technologies.(FC9) **Low Emissions** – All fuel cells exhibit negligible criteria emissions and very low CO2 emissions if “clean” fuels such as NG or renewable sources are used to generate the fuel cell hydrogen.(FC:8,9)
Potential	The potential market for this technology is projected to range from small residential to wholesale DG power generation.

Source: Navigant Consulting, Inc.

[11] Emissions values assume a fuel reforming subsystem using natural gas.

Fuel Cells – Adoption Barriers

Barriers to widescale adoption of fuel cell technology are outlined in Table 7 below. The most significant technological barriers to widescale adoption of fuel cells are unproven reliability, low stack life, and fuel reformer system design. The most significant regulatory and market barriers to widescale adoption of fuel cells are the high capital costs, low production volume and capacity, and undetermined interconnection rules.

Table 7. Fuel Cell Adoption Barriers

	Adoption Barriers– Fuel Cells
Technology	**Performance** • For PEMFCs and PAFCs the catalyst is highly susceptible to poisoning from CO and sulfur, thus limiting the sources of fuel and resulting in the need for expensive external fuel reforming subsystems and high purity hydrogen fuel.(FC:2,8) • For PEMFCs low quality exhaust heat limits CHP potential. • For MCFCs and SOFCs long heat up and cool down times restrict load cycling and result in slow transient performance.(FC:1,8,9) **Reliability** • Long-term performance reliability of fuel cell systems has not been significantly demonstrated to the market.(FC3) • Stack life/durability and stack replacement costs remain unresolved issues towards reducing total costs. (FC:1,9) • For MCFCs and SOFCs high operating temperatures place demands on corrosion stability and life of cell components.(FC:7,8) **Technical** • Major activities are needed in reformer design, size reduction, low cost material alternatives, system complexity reduction, and increasing power density.(FC:3,9) • Fuel cells must continue to be developed to utilize a wide variety of fuels as a feedstock to produce hydrogen(FC3) • For SOFCs the development of suitable high temperature materials and fabrication of ceramic structures are key
Regulatory	Issues concerning interconnection rules affecting fuel cell adoption include determining the interconnection standards to be set for distributed resources in various utility service territories. Other regulatory issues affecting fuel cell adoption include: • determining governmental rules and regulations regarding insuring, and certifying fuel cell products, • determining what depreciation schedules will be allowed, how distribution charges will be assessed, how competitive transition charges (CTC) will be assessed.(FC3)
Market	**High capital cost** • High capital costs stem from the use of expensive materials (heat resistant and precious metals), system complexities (external/internal fuel reformers, power inverters, and corrosive electrolytes), and suboptimal manufacturing techniques.(FC:8,9,12) **New technology adoption barrier** • Relatively new technologies represent a potential technical risk for early adopters and lack support infrastructure and qualified service and maintenance personnel.(FC:3,8) **Hydrogen infrastructure** • Since hydrogen is the ideal fuel for all fuel cells an infrastructure for producing, distributing, storing, delivering and maintaining hydrogen fuel is important; the lack of this infrastructure is a barrier. **Production and service base** • Limited fuel cell manufacturers results in low production and servicing capacity, low competition and slower technical innovation.

Source: Navigant Consulting, Inc.

Fuel Cells – Existing Research

There is over $300 million of federal and private funds for fuel cell research in 2009; however much of the funds are being spent on PEMFCs for transportation applications. Table 8 below lists current research on fuel cell technology.

Table 8. Fuel Cell Research

Existing Research– Fuel Cells	
US DOE / National Labs	**US DOE SECA Program –** A 10 year program with goals to resolve key technical challenges (high temperature materials, fuel reforming, cell poisoning), improve manufacturing techniques, improve performance, and reduce cost of SOFCs. The major program goal is to reduce the cost of SOFCs to 400 $/kW. SECA funding is $80 million.(FC15) **US DOE Office of Energy Efficiency and Renewable Energy** – Working to lower the cost and improve the durability of PEM fuel cells. Current R&D activities focus on improving electrocatalysts, membranes (both for ambient and high-temperature applications), and bipolar plate materials.(FC17) They also work to overcome technical barriers through R&D of hydrogen production, delivery, and storage technologies. FY09 $200 million requested FY10 $68 million. **US DOE Office of Basic Energy Science/LANL**– The emphasis is on defining the knowledge that enables new and novel materials to transcend the barriers for low-cost and high efficiency energy conversion applications. New and improved materials need to be developed for electrodes, electrolytes, membranes, and catalysts to enable innovative PEM fuel cell components and operating concepts.(FC17) FY09 $36.5 million, requested FY10 $36.5 million. **US DOE Office of Fossil Energy –** Their fuel cell related funding was $21 million in FY09, they have requested $16 million in FY10, they are planning to ask for an additional $58 million for the SECA program. **US DOE Office of Nuclear Energy –** Their fuel cell related funding was $7.5 million in FY09, they haven't requested a budget for FY10. **National Energy Technology Laboratory (NETL) Energy System Dynamic –** Focus areas include addressing turbines for fuel cell hybrids, fuel processing for fuel cells, gas cleanup technology that can allow fuel cells to operate on existing infrastructure fuels, and fuel cell degradation.(FC16) **US Department of Defense Fuel Cell Test and Evaluation Center** – Fuel Cell Test and Evaluation Center (FC*Tec*) is a facility for the independent, unbiased testing and validation of fuel cell systems for both military and commercial applications. Their focus has recently shifted from advancing from fuel cell T&E to alternative power & Energy RDT&E. **The American Recovery and Reinvestment/Industry Partners –** $41 million in public money, which is being matched by $72 million from private industry partners, is being spent to support 13 fuel cell projects with the goal to help accelerate the commercialization and development of fuel cells. Most of these projects are for small scale applications of fuel cells(<300kW). The increase in manufacturing volume in key early markets will also bring costs down and encourage the growth of a domestic supplier base.(FC14)
California / PIER	**California Fuel Cell Partnership (CaFCP) –** Members of CaFCP are demonstrating fuel cell vehicles under day-to-day driving conditions. In addition, the CaFCP is examining fuel infrastructure issues and beginning to prepare the California market for this new technology. (FC23) **California Stationary Fuel Cell Collaborative** (CaSFFC) – Developed a Strategic Plan in March 2002 to address issues facing fuel cells, such as high capital costs of fuel cell product, the undemonstrated durability and reliability of fuel cell technology, and the regulatory and policy hurdles associated with distributed generation. Recently, the PIER AG program participated in the CsSFFC, and the CaSFFC helped in the preparation of draft RD&D roadmaps for fuel cells.(FC40) **PIER –** PIER has funded a number of projects and reports on fuel cells. The Advance Generation program has identified various research plans, focus targets, and stretch goals for current and future fuel cell research and development activities for planar SOFCs, PEMFCs, and MCFCs. Research plans include addressing issues such as stack integrity and stack material engineering, pressurized operation, transfer of vehicular fuel cell advances to stationary fuel cell technology, multiple fuel capability, and demonstrations which are designed to rigorously test robustness, maintainability, stack lifetime, thermal cycling, and flexibility in operation.(FC39)

Table 8. (Continued)

Existing Research– Fuel Cells	
Universities/ Consortiums	**Fuel Cell Research Center Coordination Committee –** Goal is to provide a framework whereby research activities in the area of fuel cell testing and other areas of mutual interest are more closely coordinated. (FC26) **University of California, Irvine's National Fuel Cell Research Center (NFCRC) –** Focus is to facilitate, demonstrate and accelerate the development and deployment of fuel cell technology and fuel cell systems; promote strategic alliances to address the market challenges associated with the installation and integration of fuel cell systems.(FC3) **US Fuel Cell Council (USFCC) –** The U.S. Fuel Cell Council is an industry association dedicated to fostering the commercialization of fuel cells. USFCC views themselves as the voice of the fuel cell industry. They bring the message of fuel cells to potential customers, suppliers, technical and scientific organizations, governments at all levels, the media and opinion leaders, and the international community

Source: Navigant Consulting, Inc.

Hybrid Fuel Cell Gas Turbine Cycles – Overview

Hybrid fuel cell gas turbine cycle systems have the highest efficiency among distributed generation technologies and offer superior emissions performance. This technology is still in the commercial development stage; there have been two successful demonstrations of this technology, and smaller (1-5 MW) systems for DG applications can be expected in the near term. Because early systems will integrate two emerging advanced generation technologies (high-temperature fuel cells and microturbines), the costs of these systems may prove to be very high initially. There are still gaps in current research efforts with hybrid fuel cell gas turbine cycles. Because these systems are complex and leverage emerging technology, the front-end risk with developing these systems is high; broad investment from industry, national laboratories, and university R&D programs is required to advance this technology. General advancement of SOFC and MCFC technology is required to enable the fuel cells to meet the demands that hybrid cycles might place on them, especially in understanding pressurized operation, increasing fuel cell power density, improving robustness, and reducing costs. Lastly, specialized turbines must be developed that can both handle the flow and thermal input features that a fuel cell can provide, as well as perform well under these conditions

Hybrid Fuel Cell Gas Turbine Cycles – Description

Other hybrid fuel cell systems exist such as fuel cell/steam turbine and fuel cell/reciprocating engine, but fuel cell/gas turbine systems are the most developed. Hybrid fuel cell gas turbine cycles integrate fuel cell technology with conventional gas turbine cycle technology. High temperature fuel cells such as SOFCs or MCFCs are typically used in these systems because they exhibit the operating and exhaust temperatures necessary to effectively power a gas turbine cycle. A myriad of potential configurations exists with hundreds of cycles proposed and investigated. In each case these hybrid cycles exhibit a synergistic energy and environmental performance enhancement through novel individual technology components, unique systems integration, advanced energy conversion devices, innovative pollutant mitigation approaches, and/or increased fuel flexibility and applicability. The primary design features of fuel cell gas turbine hybrid systems are:

- Convert most of the fuel to electricity in the fuel cell leading to low emissions and relatively high efficiency.
- Use high-temperature, high-pressure waste heat streams from the fuel cell and turbine to pre-heat air and reactants, provide energy for fuel processors and off-gas burners, and provide hot gas for the turbine.
- Use high pressure produced by gas turbine in a manner that improves fuel cell output and efficiency.
- Use separated fuel and oxidant streams of fuel cell to enhance other features of the hybrid cycle (HF3).

Hybrid systems have been developed and proposed for operation on natural gas, coal, biomass, and other fossil fuels (HF3).

Both experimental and theoretical analyses of such hybrid gas turbine fuel cell systems have indicated that such hybrid systems can achieve very high fuel-to-end-use efficiency. Integrated hybrid fuel cells exhibit fuel-to-electricity efficiencies higher than either the fuel cell or gas turbine alone and costs for a given efficiency that may become lower than either alone (HF3).

The future potential applications of fuel cell hybrid systems are diverse and include large power plants operated on a variety of fuel resources, distributed generation support of traditionally energy intensive industries, local commercial applications, and various distributed generation scenarios (HF3).

Smaller-sized systems for DG applications (1-5 MW) can be expected in the near term. Larger units 5-10 MW will be introduced later and will be more appropriate for large industrial and utility power plants (FC5). There are MCFC systems in development with target sizes of 14 and 40 MW (FC4).

Smaller (1-5 MW) commercial hybrid fuel cell gas turbine systems can be expected in the near term. Table 9 below lists key characteristics of hybrid fuel cell gas turbine systems. The primary driver for hybrid fuel cell systems is their superior efficiency and emissions performance (HF3).

Table 9. Hybrid Fuel Cell Gas Turbine Cycles Technology Characterization

Technology Characterization – Hybrid Fuel Cell Gas Turbine Cycles	
Description	**Size** – Smaller-sized systems for DG applications (1-5 MW) can be expected in the near-term. Larger units 5-10 MW will be introduced later and will be more appropriate for large industrial and utility power plants.(FC5) There are MCFC systems in development with target sizes of 14 and 40 MW.(FC4) **Efficiency** • The fuel-to-electricity efficiencies of MCFC systems are expected to be 51-68 percent(HHV).(FC:2,3) • The fuel-to-electricity efficiencies of SOFC systems are expected to be 50-77 percent(HHV).(HF3) • In general larger systems have the potential to exhibit higher efficiencies.(HF:2,3,5)
Emissions	Both experimental and theoretical analyses of such hybrid gas turbine fuel cell systems have indicated that such hybrid systems can achieve very low emissions.(HF3) **CO2**[12] • 630-800 lb/MWh depending on the efficiency of the system (FC2) **Criteria Pollutants** • The criteria pollutants of these systems will be negligible since most of the electricity is produced by a clean electrochemical process rather than combustion. FuelCell Energy's MCFC hybrid system is projected to produce less than 0.1ppm (17 lb/MM-yr) NOx emissions and emission monitoring tests of their alpha prototype system have shown compliance with the most stringent environmental regulatory standards.(HF2)
Benefits	**Reduced Emissions** – These systems use clean fuel cell technology and exhibit very high efficiencies; therefore they will also exhibit extremely low emissions. Additionally the exhaust streams will have high CO2 concentrations that can allow for cost effective CO2 separation, compression and sequestration to be added to these systems.(HF2) **Application Flexibility** – These systems are being designed at various sizes for applications that range from local commercial and DG applications to large power stations. **Reduced Fuel Use** – The high efficiencies of these systems means they have the potential to use less fossil fuel to produce the same amount of energy.(HF2) **Ease of Siting** – The low emissions, low noise, and potential for small footprints will allow local permitting in grid-congested areas and will open opportunities for siting in both rural and urban areas.(HF2) **Fuel Diversity** – In addition to the fossil based fuels such as natural gas and gasified coal, the hybrid system can use a variety of biomass-derived fuels including landfill gas and digester gas. **Utilizes Existing Technology** – Current fuel cell technology in a hybrid system do not require gas turbines which operate at high temperatures or pressure ratios; therefore, less sophisticated gas turbine technology may be all that is required for a hybrid system in the short-term.(HF3)
Potential	The initial market niche for the early product entry will likely be the distributed power market in city and urban areas that suffer severe air pollution. Future markets can include other power generating market segments.(HF5)

Source: Navigant Consulting, Inc.

Hybrid Fuel Cell Gas Turbine Cycles – Adoption Barriers

Barriers to widescale adoption of hybrid fuel cell gas turbine technology are outlined in Table 10 below. The most significant barriers to adoption are the high front-end risk and cost of developing these systems.

[12] The CO2 emissions assume that natural gas is used and assumes a carbon content of 34 lb/MMBtu.

Table 10. Hybrid Fuel Cell Gas Turbine Cycles Adoption Barriers

Adoption Barriers– Hybrid Fuel Cell Gas Turbine Cycles	
Technology	**Performance** • In the short-term improvements in gas turbine compressor and turbine efficiency are desirable.(FC3) • General advancement of SOFC and MCFC technology is required, especially in understanding pressurized operation and increasing fuel cell power density.(FC3) • Research is required to enable fuel cells to meet the demands that hybrid cycles might place on them. This will entail research about advanced materials (for increased current density and mechanical strength), decreasing the air to fuel ratio, improving the heat transfer to remove heat generated by the cell, and improving fuel flexibility.(FC3) • Integrating fuel cells and current turbines is challenging; existing turbines do not match the pressure ratios, mass flows, and other critical operating and performance parameters of the small high temperature fuel cells that are currently available.(FC3) • Specialized turbines must be developed that can both handle the flow and thermal input features that a fuel cell can provide, as well as perform well under these conditions.(FC3) • As fuel cells advance and scale-up and pressurization of MCFC and/or SOFC technology becomes viable, larger, and more sophisticated gas turbine engines (for example, axial compressors and turbines, higher pressure ratios, high turbine inlet temperature) will be required.(FC3) • Inverters and power electronics must be designed and manufactured specifically for fuel cell hybrids with the understanding that accepting input from both the heat engine and fuel cell would be preferred.(FC3) **Reliability** • Because this is a new technology, and involves the complex technical task of integrating two generation technologies, the barrier of demonstrating the reliability and availability of the technology must be overcome.
Regulatory	Since the initial market will likely be in the DG market, all of the regulatory barriers that exist for DG technologies will apply to hybrid fuel cell gas turbine technologies. These barriers involve interconnection standards, permitting, tax depreciation schedules, governmental rules and regulations regarding insuring, and certifying, etc.
Market	Because this hybrid technology leverages fuel cells, it faces similar market barriers **High Cost** Significant improvement of high temperature fuel cell technology robustness and cost is required for he development of hybrid gas turbine fuel cell systems.(FC3) The front-end risk associated with developing this technology is considerable. Broad investment in ndustry, at national laboratories, and in university research and development is required to advance ybrid gas turbine fuel cell technology.(FC3)

Source: Navigant Consulting, Inc.

Hybrid Fuel Cell Gas Turbines – Existing Research

There have been two major successful demonstrations of this technology that demonstrated its promise and that more research is required. Table 11 below lists current research on hybrid fuel cell gas turbine technology.

Table 11. Hybrid Fuel Cell Gas Turbine Cycle Research

Existing Research– Hybrid Fuel Cell Gas Turbine Cycles	
US DOE / National Labs	**NETL** - In partnership with private industries and others, NETL is leading the development and demonstration of high efficiency solid oxide fuel cells (SOFCs) and fuel cell/turbine (FCT) hybrid power generation systems. **National Fuel Cell Research Center (NFCRC) –** The NFCRC was part of a collaborative effort with Siemens to design and test a 220kW SOFC gas turbine hybrid prototype system.(HF8) **NETL's Hybrid Performance Simulation Facility** – Researchers at NETL have completed shakedown of an experimental facility capable of physically simulating the dynamic operation of a FCT hybrid system. The hardware-in-the-loop simulation facility enables researchers to identify dynamic issues related to the interdependencies of fuel cell and turbine technology integration without risk to expensive fuel cell stacks. (HF8) **Solid State Energy Conversion Alliance (SECA)** – The application of fuel cell systems and ultimately FCT hybrids is limited by the high cost of the fuel cell. To address the cost issue, the US DOE is implementing the SECA program. The SECA program is dedicated to developing innovative, effective, low-cost ways to commercialize SOFCs. NETL is partnering with Pacific Northwest National Laboratory in developing new directions in advanced materials, processing and system integration research under the SECA initiative for the development and commercialization of modular, low cost, and fuel flexible 3- to 10-kWe SOFC systems by 2010.(HF8)
California / PIER	**PIER –** The AG program has research plans for current and future micro and small gas turbine/fuel cell hybrid systems. Research activities focus on the resolution of thermal and gas flow integration issues, and system demonstrations for grid-connected operation of properly sized micro or small gas turbines and fuel cells for hybrid applications. The PIER AG program also sponsored the Siemens hybrid SOFC demonstration and commissioned the final report.(HF:10,11)
Universities	**Advanced Power and Energy Program, University of California Irvine –** Under sponsorship of the US DOE, this a multi-disciplinary team is defining the system engineering issues associated with the integration of key components and subsystems into large power plant systems that meet stretch performance and emission goals for both natural gas and coal fuel operation. This study determined that the only technology that could meet these goals is hybrid gas turbine fuel cell technology.(HF3)

Table 11 (Continued)

Existing Research– Hybrid Fuel Cell Gas Turbine Cycles	
Private Sector	**GE** – The Hybrid Power Generation Systems Division of General Electric SECA project includes the sub-MW design and test of a Solid State Energy Conversion Alliance (SECA) solid oxide fuel cell and a microturbine. The project evaluated several turbine cycle configurations, including topping, bottoming, direct and indirect, and allowed for the evaluation of integration and scale-up issues for SECA-based hybrid systems.(HF3) **Siemens/Ingersoll Rand** - The Siemens Power Corporation received funds from the SECA and PIER program to develop a hybrid design that included a 100 kW tubular SOFC integrated with a 60 kW Ingersoll Rand microturbine generator. This system was built and tested at the National Fuel Cell Research Center, in Irvine, California. Test included pressurization of the fuel cell to provide a total of 220 kW of power from the hybrid system. The system operated for 2900 hours with conversion efficiencies of 53 percent (HHV).Testing proved that high efficiency and ultra-low emissions was achievable with these types of hybrid cycles, but, that integration and operation is considerably difficult with such complex hybrid systems.(HF3) **Fuel Cell Energy/Capstone** – They are developing a MCFC/Gas turbine hyrbid system that leverages its commercially available Direct Fuel Cell (DFC) fuel cells. The system combines a non-fired gas turbine and a network of heat exchangers to transfer waste heat from the fuel cell to the turbine, resulting in extra electricity and adding 10 to 15 percentage points to the efficiency of the DFC (43 percent+10-15 percent HHV). In addition to the fossil based fuels such as natural gas and gasified coal, the hybrid system can use a variety of biomass derived fuels including landfill gas and digester gas. They completed a field demonstration of a packaged sub-megawatt (250kW FC/30kW microturbine) class alpha power plant unit. The power plant achieved a record-breaking electrical efficiency of 51 percent (HHV). Additionally it exhibited extremely low emissions and achieved an availability of greater than 91 percent over 8000 hours of operation. In addition they are one of six SECA industry partners and are receiving development money from the US DOE. They are in the process of investigating SOFC hybrid systems as well.(HF2) **Rolls-Royce** – They are developing a megawatt scale SOFC hybrid system. If testing goes according to plan, Rolls-Royce believes the generators will be ready for commercial sale in 2010.(HF7)

Source: Navigant Consulting, Inc.

Reciprocating Engines – Overview

Reciprocating engines have low first costs, proven reliability when properly maintained, and significant heat recovery potential. The major barriers facing reciprocating engines are high maintenance costs and frequent maintenance intervals. Current research is exploring technology improvements to reduce operating and maintenance costs. Reciprocating engines are limited to lower temperature cogeneration applications because full waste heat recovery is still being explored. There are still gaps in current research efforts with reciprocating engines. Research into using landfill gas and digester biogas is underway but can be expanded to address fuel flexibility for increased CHP potential. Also, the US DOE's target for fuel-to-electricity efficiency (Lower Heating Value [LHV]) for gas-fired reciprocating engines is 50 percent by 2010—a 30 percent increase over today's average efficiency. This goal needs to be supported by further research.

Reciprocating Engines – Description

Reciprocating engines are available from small sizes (for example, 5 kW for residential backup generation) to large generators (for example, 7 MW). A reciprocating, or internal combustion (IC), engine converts the energy contained in a fuel into mechanical power. This mechanical power is used to turn a shaft in the engine. A generator is attached to the IC engine to convert the rotational motion into power (RG18). Reciprocating engines are available in sizes from 10 kW to more than 5 MW (RG1).

Reciprocating engines primarily use natural gas or diesel, depending on the type of engine, but can also be run on propane, gasoline, or landfill gas (RG1). System efficiencies are 50 percent thermal, 80+ percent with CHP (RG6).

Potential distributed generation applications for reciprocating engines include standby, peak shaving, grid support, and CHP applications in which hot water, low-pressure steam, or waste-heat-fired absorption chillers are required. Reciprocating engines are also used extensively as direct mechanical drives in applications such as water pumping, air and gas compression, and chilling/refrigeration. (RG1)

Sub-technologies of reciprocating engines are:

- Spark Ignition – In spark ignition (SI), a spark is introduced into the cylinder (from a spark plug) at the end of the compression stroke (RG18).
- Compression Ignition – In compression ignition (CI), the fuel-air mixture spontaneously ignites when the compression raises it to a high-enough temperature (RG18).

Spark ignition reciprocating engines allow for fuel flexibility. Table 12 below lists key characteristics of SI engines.

Table 12. Reciprocating Engine Sub-Technology Characterization – Spark Ignition

Sub-Technology Characterization – Spark Ignition	
Description	**Size** – Spark ignition (SI) engines for power generation applications are primarily 4-stroke engines available in sizes up to about 5 MW (RG1) **Fuel** – SI engines for power generation use natural gas as the preferred fuel, although they can be set up to run on propane, gasoline, or landfill gas (RG1). **Efficiency** – Natural gas SI engine efficiencies range from about 28 percent for small engines (<50 kW) to 42 percent for the largest high performance, lean burn engines (RG1). Overall CHP system efficiencies (electricity and useful thermal energy) of 65 to 80 percent are routinely achieved with natural gas engine systems (RG1) **Applications** – Natural gas-fueled SI engine is now the engine of choice for the higher-duty-cycle stationary power market (RG1). The most prevalent on-site generation application for natural gas SI engines has traditionally been CHP (RG1).
Cost	**Total Installed Cost** • Installed cost depends on system size: ~$2,200 for a 100 kW system; $1,100 for a 5MW system (RG2) **O&M Cost** • Depending on system size: $0.02 for a 100 kW system; $0.01 for a 5 MW system (RG2)
Emissions	For a 5 MW natural-gas fueled spark ignition engine: **CO2** • 1,024 lbs/MWh (RG2) **Criteria Pollutants** • NOx: 1.24 lbs/MWh (RG2) • CO: 0.75 lbs/MWh (RG2)
Benefits	• Current generation natural gas SI engines offer low first cost, fast start-up, proven reliability when properly maintained, excellent load-following characteristics, and significant heat recovery potential (RG1) • Multiple SI engine units further increase overall plant capacity and availability (RG1) • Reciprocating engines have higher electrical efficiencies than gas turbines of comparable size, and thus lower fuel-related operating costs. In addition, the first costs of reciprocating engine gensets are generally lower than gas turbine gensets up to 3-5 MW in size (RG1)
Potential	• Spark-ignited engines fueled by natural gas or other gaseous fuels represent 84 percent of the installed reciprocating engine CHP capacity (RG1).

Source: Navigant Consulting, Inc.

Compression ignition reciprocating engines run primarily on diesel but can be operated in a dual-fuel configuration with natural gas. Table 13 below lists key characteristics of CI engines.

Table 13. Reciprocating Engine Sub-Technology Characterization – Compression Ignition

Sub-Technology Characterization – Compression Ignition	
Description	**Size** – High speed diesel compression ignition (CI) engines (1,200 rpm) are available up to about 4 MW in size. Low speed diesels (60 to 275 rpm) are available as large as 65 MW (RG1) **Fuel** – CI engines (often called diesel engines) operate on diesel fuel or heavy oil, or they can be set up to run in a dual-fuel configuration that burns primarily natural gas with a small amount of diesel pilot fuel (RG1). **Efficiency** – Efficiency levels increase with engine size and range from about 30 percent for small high-speed diesels up to 42 to 48 percent for the large bore, slow speed engines (RG1). **Applications** – Diesel CI engines have historically been the most popular type of reciprocating engine for both small and large power generation applications (RG1). Principal use is for stand-by or emergency power (RG16).
Cost	**Total Installed Cost** • $800/kW (RG12) **O&M Cost** • Fixed: $4/kW/yr (RG11) • Variable: $9.15/MWh (RG11)
Emissions	**CO2** • 1615 lb/MWh (RG11) **Criteria Pollutants** • Depending on the engine and fuel quality, diesel CI engines produce 5 to 20 times the NOx (on a ppmv basis) of a lean burn natural gas engine (RG1) • New diesel CI engines using low sulfur diesel will achieve rates of approximately 0.65 lb NOx/MWh (RG1) • Diesel CI engines also produce assorted heavy hydrocarbons and particulate emissions (RG1) • Diesel CI engines produce significantly less CO than lean burn gas engines (RG1) • NOx: 3-8 lbs/MWh (RG1)
Benefits	• Quick starting (RG16) • Runs on stored fuel (RG16)
Potential	• Diesel compression egnition engines make up about 9 percent of the reciprocating engine market (RG17).

Source: Navigant Consulting, Inc.

Reciprocating Engines – Adoption Barriers

Barriers to widescale adoption of reciprocating engine technology are outlined in Table 14 below. The most significant barriers to widescale adoption of reciprocating engines are high maintenance costs and frequent maintenance intervals.

Table 14. Reciprocating Engines Adoption Barriers

	Adoption Barriers– Reciprocating Engines
Technology	• Reciprocating engine maintenance costs are generally higher than comparable gas turbines (RG1) • Limited to lower temperature cogeneration applications (RG2) • Relatively high NOx emissions (RG2) • Must be cooled even if recovered heat is not used (RG2) • High levels of low frequency noise (RG2) • Full utilization of the varied heat sources is difficult (RG13) • Frequent maintenance intervals - every 600 to 1000 hours (RG13)

Source: Navigant Consulting, Inc.

Reciprocating Engines – Existing Research

Most reciprocating engine research focuses on spark ignition engines. Fuel flexibility with spark ignition engines is also being explored. Table 15 below lists current research on reciprocating engine technology.

Table 15. Reciprocating Engines Research

Existing Research– Reciprocating Engines	
US DOE / National Labs	• The US DOE's Distributed Energy Program conducts research on gas-fired reciprocating engines for distributed energy applications in industrial, commercial, and utility settings (RG5) • In September 2001, the US DOE announced that six universities had been selected for cost-shared grants covering seven reciprocating engine projects. US DOE is investing $3.6 million of the projects' combined value of $4.6 million (RG5) • The goals of the Advanced Reciprocating Engines Project are to increase the energy efficiency of medium-size natural gas engines from 34 percent-38 percent to 50 percent, reduce nitrogen oxides emissions from 1 gram per horsepower-hour to 0.1 gram per horsepower-hour, and reduce operating and maintenance costs by 10 percent (RG5) • NETL's reciprocating engine laboratory focuses on research to enable high efficiency, cleaner burning engines. Research includes diesel engine particulate studies. (RG12)

Universities	• Fiscalini Farms Renewable Energy Power Generation Project – University of the Pacific, Biogas Energy, Inc., and the University of California at Berkeley are researching a system that will use digester gas from an anaerobic digester located at the Fiscalini Farms dairy for power generation with a reciprocating engine. The project will provide power, efficiency, emissions, and cost/benefit analysis for the system and evaluate its compliance with federal and California emissions standards (RG9)
	  o Estimated Funding: $1,558,600 total; $779,300 from US DOE
	• Colorado State University - Fundamental Studies of Ignition Process in Large Natural Gas Engines Using Laser Spark Ignition (RG15)
	  o $736,839 Total Contract Value; $500,000 from US DOE

Private Sector	• Integrated Advanced Reciprocating Internal Combustion Engine System for Increased Utilization of Gaseous Opportunity Fuels – Gas Technology Institute will collaborate with Integrated CHP Systems Corporation, West Virginia University, Vronay Engineering Services, KAR Engineering Associates, Pioneer Air Systems, and Energy Concepts Company to recover waste heat from reciprocating engines. The project will integrate waste heat recovery along with gas clean-up technology system improvements. This will address fuel quality issues that have hampered expanded use of opportunity fuels such as landfill gas, digester biogas, and coal mine methane. This will enable increased application of CHP using renewable and domestically derived opportunity fuels (RG10) • Estimated Funding: $2,020,203 total; $1,284,709 from US DOE • Gas Technology Institute (GTI) is conducting research to develop waste-heat recovery/fuel-reforming technology to provide high-efficiency, clean combustion for reciprocating internal-combustion engines fueled with natural gas. Preliminary studies show a potential increase in thermal efficiency of 15 percent. Potential applications for the technology include reciprocating engines used in stationary power systems (RG14)

Source: Navigant Consulting, Inc.

Stirling Engines – Overview

Stirling engines have relatively high capital costs but can achieve low emissions compared to internal combustion engines. Stirling technology has not undergone a robust research and development phase, which contributes to its lack of proven operation and durability. Further, these engines are manufactured in very low quantities, resulting in their high capital cost. There isn't a large amount of research involving Stirling engines, but the little that is done surrounds using landfill gas as fuel, as well as using Stirling engines for concentrated solar. Stirling engines are typically used in small-scale applications such as residential and small commercial CHP, but research into creating pre-packaged systems and addressing costs and reliability is still lacking.

Stirling Engines – Description

Stirling engines are classed as external combustion engines. The Stirling cycle uses a working fluid (typically helium, nitrogen or hydrogen gas) in a closed cylinder containing a piston. Heated on one end and cooled on the other, the expansion and cooling of the gas drives the piston back and forth in the cylinder. The work performed by this piston-motion is used to drive a generator. In kinematic Stirling engines, two pistons are physically connected by a crank mechanism, whereas in free-piston Stirling engines, there is no physical linkage and the displacer oscillates resonantly (SE4).

Stirling engines are typically very small, ranging in size from <1 kW to 25 kW (SE1). They run primarily on natural gas, but broad fuel flexibility is possible (SE1). STM Power offers 55-kW units that are able to run on a variety of fuels, including natural gas, biogas, and palm oil (SE2). The efficiency of Stirling engines ranges from 12-30 percent, with a target efficiency of over 30 percent (SE1). Stirling engines are typically used in small-scale applications such as residential uses or portable power generation (SE1).

Sub-technologies of Stirling engines are:

- Free-piston – Free-piston engines are generally most applicable to DR applications where electric grid power is available to stabilize the operating frequency of the engine (SE8)
- Kinematic – Kinematic engines are applicable to both grid-parallel and stand-alone DR applications (SE8)

Stirling engines have relatively high capital costs but can achieve low emissions compared to internal combustion engines. Further, Stirling engines are small and quiet and are well-suited for microCHP. Table 16 below lists key characteristics of Stirling engines.

Table 16. Stirling Engines Technology Characterization

<table>
<tr><th colspan="2">Technology Characterization – Stirling Engines</th></tr>
<tr><td>Cost</td><td>Total Installed Cost ($/kW)
Capital costs of Stirling engines are relatively high ($2,000-$50,000/kW) and are generally not cost competitive with other DG technologies (SE1)
Stirling engine manufacturers target lower costs (~$2000/kW) if higher production volumes are achieved (SE1)
STM Power’s 55-kW product sells for $1,200/kW (SE2)

<b>O&M Cost ($/kWh)
Stirling engine developers estimate O&M cost of approximately 0.5-1¢/kWh (SE8)</td></tr>
<tr><td>Emissions</td><td>• Stirling engines can achieve low emissions of criteria pollutants relative to internal combustion engines (SE6)
• Stirling engines used with landfill gas have low emissions compared to reciprocating engines (SE7)
• The emissions from Stirling engines are typically low and easily controlled (SE8)
CO2
• CO2 emissions are a function of fuel used and engine efficiency.
Criteria Pollutants
• For a 4-120 natural gas burning Stirling engine:
o NOx – 1 lb/MWh (SE8)
o CO – 6 lbs/MWh (SE8)
o VOC – 1 lb/MWh (SE8)</td></tr>
<tr><td>Benefits</td><td>• Electrical efficiencies between 12-20 percent, low noise and vibrationless operation , low emissions, low maintenance, and high reliability, multi-fuel capability, long life(1)
• Quiet operation (2)
• Multiple fuels (natural gas, gasoline, solar, alcohol, wood, biofuels); low emissions potential; low noise compared to IC engines; combustion control (4)</td></tr>
<tr><td>Potential</td><td>• Small scale - residential or portable power generation. (SE1)
• MicroCHP</td></tr>
</table>

Source: Navigant Consulting, Inc.

Stirling Engines – Adoption Barriers

Barriers to widescale adoption of Stirling engines are outlined in Table 17 below. The most significant barrier to widescale adoption of Stirling engines is the lack of proven operation and durability.

Table 17. Stirling Engines Adoption Barriers

Adoption Barriers– Stirling Engines	

Technology	• Stirling technology has not undergone a robust research and development phase (SE1)
	• Low efficiencies (SE1)
	• Long start-up times (SE4)
	• Durability challenges have included:
	  • Shaft seals to separate the high pressure hydrogen space from the lubrication in the mechanical drive train (SE1)
	  • Low-leakage piston rings and bearings for operation in the unlubricated working engine space (SE1)
	  • Minimization of material stress and corrosion in the high temperature/high pressure heater head, which must operate at internal pressures of >2000 psi and 1300°F (SE1)
	  • Blockage of fine-meshed heat matrices used in the regenerator assemblies with particles/fines generated through the rubbing action of piston rings (SE1)
	• Lack of proven operation and durability is perhaps the largest hurdle in the way of Stirling engine commercialization (SE8)

Market	• Stirling engines are manufactured in very low quantities which results in the high capital cost (SE1) • Pricing and performance information is widely scattered among technology types and product sizes without a noticeable trend (SE8)

Source: Navigant Consulting, Inc.

Stirling Engines – Existing Research

Research on Stirling engines has focused on using landfill gas as fuel. Table 18 lists current research on Stirling engine technology.

Table 18. Stirling Engines Research

Existing Research– Stirling Engines	
US DOE / National Labs	• Army Research Laboratory's field power generation unit has a research program to assess the application of 1-2kW Stirling engines using JP-8 as fuel as silent mobile power. Approximately $12,000 funding over 2007-2009 (SE5) • US Climate Change Technology program conducts research to demonstrate Stirling-Cycle engines at landfills and evaluate technical, economic, and environmental performance (SE7) • Since January 2003, two 2-25 kW and 10-25 kW Stirling cycle engines using landfill gas are operational at two landfills in Michigan (SE7) • Since 1999, the Salt River Project (led by US DOE and a municipal utility located in Phoenix, Arizona) is demonstrating the operation of the first thermal hybrid-electric sundish. This technology combines solar thermal heliostats and a Stirling cycle engine using landfill gas (SE7)
Universities	University of Canterbury has a Stirling Cycle Research Group (SE3)
Private Sector	EPRI completed an industry assessment of Stirling Engines in 2002 (SE8)

Source: Navigant Consulting, Inc.

Microtrubines – Overview

Extensive microturbine research and demonstration are underway. In recent years, research has focused on using microturbines in CHP applications. Specific research needs focus on improving microturbine efficiencies and fuel flexibility. Microturbine manufacturers have promised cost reduction with higher rates of production and sales, but to date, significant cost reductions have not materialized. Despite the extensive research, there are still some research gaps. Research into cycle enhancement could address loss of power output and efficiency at higher ambient temperatures and elevation. Further, opportunities exist for improving microturbine efficiency by pairing microturbines with fuel cells.

Microturbines – Description

Most microturbines are single-stage, radial-flow devices with high rotating speeds of 90,000 to 120,000 revolutions per minute. While some early product introductions have featured unrecuperated designs, the bulk of developers' efforts is focused on recuperated systems. The recuperator recovers heat from the exhaust gas to boost the temperature of the air stream supplied to the combustor. Further exhaust heat recovery can be used in a cogeneration configuration. (MT27)

Microturbines are small combustion turbines, approximately the size of a refrigerator, with outputs of 25-500 kW (MT7). Microturbines can operate on a variety of primary fuels including natural gas, propane, diesel, and kerosene (MT1). As cogeneration units, the overall efficiency of microturbines can be 70-80 percent (MT1). The high heat-to-power ratio of microturbines yields electrical efficiencies of only 20 percent to 30 percent (MT6).

Microturbines are used in a wide variety of applications, including: peak shaving and baseload power (grid parallel), combined heat and power, stand-alone power, backup/standby power, ride-through connection, primary power with grid as backup, microgrid, and resource recovery (MT2).

Sub-technologies of microturbines are:

- Single- or two-shaft
- Simple cycle
- Recuperated

Microturbines are attractive due to their low emissions. Further, microturbines have high efficiencies and can serve large loads when connected in parallel. Table 19 below lists key characteristics of microturbines.

Table 19. Microturbine Technology Characterization

Technology Characterization – Microturbines	
Cost	**Capital Cost** The package cost ranges between $1,300 for a 30kW system to $1,400 for a 250kW system (MT2) **Installed Cost** The installed cost runs from $3,000 for a 30kW system to $2,500 for a 250kW system. (MT2) (Installed costs based on CHP system producing hot water from exhaust heat recovery) (MT2) **O&M Cost** O&M costs ($/kW) range from $0.015 - $0.025 for a 30kW system to $0.012 - $0.020 for a 250 kW system (MT2) The cost of a major overhaul can range from $550 to $800/kW (MT2)
Emissions	**CO2** • 1.34 to 3.9 lbs/kWh (MT23). **Criteria Pollutants** • Low inlet temperatures and high fuel-to-air ratios result in NOx emissions of less than 10 parts per million (ppm) when running on natural gas (MT2) • Commercial units have been certified to meet extremely stringent standards in Southern California of less than 4-5 ppmvd of NOx (15 percent O2.) CO and VOC emissions are at the same level (MT2)
Benefits	• Units may be connected in parallel to serve larger loads and provide power reliability (MT2) • ‘Black start’ capability, enabling the system to operate with or without a grid interconnection (MT6) • High overall efficiencies of up to 85 percent with heat recovery (MT6) • Small number of moving parts, compact size, lightweight, greater efficiency, lower emissions, lower electricity costs, and ability to use waste fuels (MT7) • Increased heat output for absorption chilling or other heat uses (MT12)
Potential	• The US DOE’s Energy Information Administration reports that approximately 380 gigawatts of new electric capacity will be added to the nation’s power fleet by 2020, including retirements of existing facilities. The market share for distributed energy resources has been estimated to range from 10 to 20 percent of these capacity additions, or 38 to 76 gigawatts. Because of their compact size, relatively low capital costs, and expected low operations and maintenance costs, microturbines are expected to capture a significant share of the potential distributed generation market. (MT18) • The DG market will continue to be dominated by gas and diesel engines for the next 10 years, with all other technologies, including fuel cells, small gas turbines and microturbines only supplying 10-15 percent. (MT22) • US Environmental Protection Agency (EPA) estimates the total installed capacity of microturbine/CHP systems should reach 55 MW by 2011 (MT23)

Source: Navigant Consulting, Inc.

Microturbines – Adoption Barriers

Barriers to widescale adoption of microturbine technology are outlined in Table 20 below. The most significant barriers to wide-scale adoption of microturbines are their high cost and their low efficiencies.

Table 20. Microturbines Adoption Barriers

Adoption Barriers– Microturbines	
Technology	• Microturbines will need to be demonstrated to verify manufacturer's claims of efficiency, emissions, and reliability (MT5) • Relatively low electrical efficiencies of 20-30 percent (MT6) • Efficiency is sensitive to changes in ambient conditions (MT6) • Loss of power output and efficiency with higher ambient temperatures and elevation (MT8)
Regulatory	• Uncertainty associated with permitting, installation, schedule (MT22)
Market	• Microturbine manufacturers have promised cost reduction with higher rates of production and sales, but to date, significant cost reductions have not materialized (MT2) • Microturbine manufacturers have made some progress in establishing a maintenance infrastructure, but to date they have not demonstrated the ability to dependably support this new technology (MT5) • Right now, microturbines generally cost 10-25 percent the price of fuel cells and about double the cost of reciprocating engines (MT12)

Source: Navigant Consulting, Inc.

Microturbines – Existing Research

The government has funded an extensive microturbine research program. Recent microturbine research has focused on microturbines in CHP applications. Further research is being done to monitor microturbine performance and emissions. Utilities are exploring microturbines used for CHP as well as hybrid microturbines. Table 21 below lists current research on microturbine technology.

Table 21. Microturbine Research

<table>
<tr><th colspan="2">Existing Research– Microturbines</th></tr>
<tr><td>US DOE / National Labs</td><td>
• On July 25, 2000, an award of $40 million for research, development, and testing of "next generation" microturbine systems was announced. The industrial partners share 40 percent of the total cost of US DOE funds awarded (most of these projects have been competed). The projects are as follows: (MT9)
o Capstone Turbine Corp. in Woodland Hills, California; awarded $10 million to achieve efficiency, emissions, and cost objectives. Capstone incorporates higher temperatures, advanced materials—including structural ceramics—and innovative designs for better performance.
o General Electric Corporate Research and Development in Schenectady, New York; awarded $4,765,994. GE's Advanced Integrated Microturbine System leverages recent advancements in large-scale turbines.
o Honeywell Power Systems Inc. in Albuquerque, New Mexico; awarded $9,993,489. Honeywell leads a multidisciplinary team to provide development, integration, and demonstration of critical components to achieve performance, emissions, and cost goals of advanced microturbine program. (no longer in business)
o Northern Research and Engineering Corp., Ingersoll-Rand Energy Systems Division in Portsmouth, New Hampshire; awarded $1,475,863. Under its PowerWorks line of industrial combined cooling, heating, and power products, Ingersoll-Rand works with ceramic suppliers to apply state-of-the-art ceramics technology to yield microturbine and air compressor products with increased efficiency and environmental benefits.
o Solar Turbines Inc. in San Diego, California; awarded $4,555,859. Solar Turbines seeks to improve the durability and cost performance of its primary surface recuperator (PSR) for microturbine systems applications. The work upgrades the temperature capability of the PSR while focusing on cost containment and reduction. The research team includes microturbine manufacturers who stress higher temperature and lower cost as critical needs for their products.
o United Technologies Research Center in East Hartford, Connecticut; awarded $8,621,434. The team, led by United Technologies Corp., demonstrates technologies which will substantially increase performance and reduce the cost and emissions of microturbines for electric utility distributed generation power systems.
• The Advanced Microturbine Program was a 6-year program for fiscal years 2000-2006 with a government investment of more than $60 million. End-use applications for the program include stationary power applications in industrial, commercial, and institutional sectors. (MT10)
• US EPA's Environmental Technology Verification program partnered with Southern Research Institute to measure emissions from 6 demonstration installations of microturbine CHP systems ranging from 30 to 75 kW (MT24)
• In May 2007, through the Federal Energy Management Program, ORNL's CHP Integration Test Facility conducted research on a 30 kW microturbine CHP system for performance, efficiency and emissions (MT25)
</td></tr>
<tr><td>California / PIER</td><td>• Microturbine Generator (MTG) Field Test Program (2002) – Research program to ascertain cost, performance, durability, reliability, and maintainability of microturbines in an actual customer environment (MT26)</td></tr>
</table>

Table 21. (Continued)

Existing Research– Microturbines	
Other States	• New York State Energy Research and Development Authority (NYSERDA) funds several microturbine research projects: o Installed 13 microturbine CHP units in Clinton Hill Apartments to supply approx. 90 percent of the apartments' electricity needs (600 kW), while the heat recovered is used for water heating. (MT14) o New York State Electric and Gas (NYSEG) microturbine demonstration at several commercial/industrial sites within the NYSEG utility service territory. The project will assess equipment installation, operating performance, and system reliability. (MT15) o Installation of two microturbines at a hotel in New York City and assessment of operating performance in day-to-day commercial service (MT16) o Demonstration of a propane-fueled microturbine cogeneration system to produce electric power and hot water for on-site processing equipment for the Old Chatham Sheepherders creamery and cheese production facility (MT17)
Universities	• Testing and validation of microturbines at the University of California-Irvine (UCI) Distributed Technologies Testing Facility; Southern California Edison is co-leading the project (MT10) o $2.1 million project, which was started in 1996, receives co-funding from the California Energy Commission and the Electric Power Research Institute (MT10) • UCI's combustion laboratory is doing research to quantify the criteria pollutants produce by microturbines (MT11) • In 2001, Cal Poly San Luis Obispo conducted a research project to explore the potential to use biogas from the Cal Poly Dairy to fuel a 30 kW grid-connected microturbine generator. The project cost $225,000. (MT19)
Utility	• Southern California Gas is demonstrating a combination microturbine and absorption chiller. (MT4) • Los Angeles Department of Water and Power (LADWP) is installing a 250 kW fuel cell at its headquarters. It is also operating fifty 30 kW microturbines at the Lopez Canyon Landfill. (MT4) • The city of Burbank is conducting a demonstration of ten 30 kW microturbines running on landfill gas. (MT4) • Southern California Edison has tested a 200kW "hybrid," combining a solid-oxide fuel cell and a microturbine to bring about significantly higher efficiencies. The project is at UC Irvine's National Fuel Research Center (MT12) • In 2004, Florida Power & Light worked with the Electric Power Research Institutes (EPRI) and the state's Tomoka Correctional Institution to study microturbine energy technology. The project placed a 60 kW Capstone microturbine at the Tomoka Correctional Institution in Daytona Beach. The project cost was $360,000 (MT13)
Private Sector	• General Electric funds an Advanced Integrated Microturbine System project to develop the next generation microturbine system that will advance the current generation system into a more efficient, cost effective, and environmentally friendly system. (MT20)

Source: Navigant Consulting, Inc.

Small Gas Turbines – Overview

Small gas turbines have proven to be reliable power generators given proper maintenance. Turbines under 3 MW cannot compete with the cost of reciprocating engines due to low production volumes and low commonality of parts among multiple turbine models. PIER has funded several small gas turbine demonstration projects to address catalytic combustion in small gas turbines. A significant number of simple-cycle gas turbine based CHP systems are in operation at a variety of applications including oil recovery, chemicals, paper production, food processing, and universities. Some research gaps for small gas turbines are surrounding improving the energy and environmental performance of small gas turbines to significantly lower capital costs. There is also a need for technology demonstrations, technical assistance in implementation, and reporting of lessons learned and best practices.

Small Gas Turbines – Description

Gas turbines can be used in power-only generation or in CHP systems. Gas turbines are successful in CHP applications because their high-temperature exhaust can be used to generate process steam at conditions as high as 1,200 pounds per square inch gauge (psig) and 900 degree Fahrenheit (°F) or used directly in industrial processes for heating or drying. (GT1)

Gas turbines are available in sizes ranging from 500 kW to 250 MW (GT1). Small gas turbines are typically < 20 MW. Gas turbines operate on natural gas, synthetic gas, landfill gas, and fuel oils (GT1). Efficiencies of small gas turbines range from 22-36 percent (GT2). Gas turbines produce high-quality exhaust heat that can be used in CHP configurations to reach overall system efficiencies (electricity and useful thermal energy) of 70 to 80 percent (GT1).

A significant number of simple-cycle gas turbine based CHP systems operate at a variety of applications including oil recovery, chemicals, paper production, food processing, and universities. Simple-cycle CHP applications are most prevalent in smaller installations, typically less than 40 MW (GT1). Gas turbines are often used for incremental capacity and grid support (GT1).

Sub-technologies of gas turbines are:

- Aeroderivative gas turbines for stationary power are available at a max of 50 MW capacity (GT1).
- Industrial or frame gas turbines are exclusively for stationary power generation and are available in the 1 to 250 MW capacity range (GT1).

Small gas turbines have low emissions and high reliability. Table 22 below lists key characteristics of small gas turbines.

Table 22. Small Gas Turbines Technology Characterization

Technology Characterization – Small Gas Turbines	
Cost	**Total Installed Cost ($/MW)** Installed cost ($/kW) depends on system size: $3,300 for a 1 MW system, and $1,300 for a 10 MW system (GT1) **O&M Cost ($/kWh)** O&M cost ($/kWh) depends on system size: $0.0111 for a 1 MW system, and $0.007 for a 10 MW system (GT1)
Emissions	**CO2** • Gas turbines emit substantially less CO2 per kWh generated than any other fossil technology in general commercial use. (GT1) **Criteria Pollutants** • Many gas turbines burning gaseous fuels (mainly natural gas) feature lean premixed burners (also called dry low-NOx combustors) that produce NOx emissions below 25 ppm, with laboratory data down to 9 ppm, and simultaneous low CO emissions in the 10 to 50 ppm range. (GT1)
Benefits	• Modern gas turbines have proven to be reliable power generators given proper maintenance. Time to overhaul is typically 25,000 to 50,000 hours. (GT1) • High reliability, low emissions, high-grade heat available, no cooling required. (GT2) • Gas turbines process more power-generation cycle air per unit size and weight of machine than do reciprocating engines and, consequently, are lighter weight and more compact (GT7)
Potential	• There were an estimated 40,000 MW of gas turbine-based CHP capacity operating in the United States in 2000 located at over 575 industrial and institutional facilities. Much of this capacity is concentrated in large combined-cycle CHP systems which maximize power production for sale to the grid. However, a significant number of simple-cycle gas turbine based CHP systems are in operation at a variety of applications, such as universities and food processing. Simple-cycle CHP applications are most prevalent in smaller installations, typically less than 40 MW. (GT3)

Source: Navigant Consulting, Inc.

Small Gas Turbines – Adoption Barriers

Barriers to widescale adoption of small gas turbine technology are outlined in Table 23 below. The most significant barrier to wide-scale adoption of small gas turbines is that they cannot compete with the cost of reciprocating engines.

Table 23. Small Gas Turbines Adoption Barriers

Adoption Barriers– Small Gas Turbines	
Technology	• Require highpressure gas or in-house gas compressor. (GT2) • Poor efficiency at low loading. (GT2) • Output falls as ambient temperature rises. (GT2)
Market	• Natural gas prices have increased substantially and been highly volatile. This has contributed to the recent slow adoption of CHP systems (GT6) • However, small gas turbines are not generally sufficiently economically attractive at the present time for intermediate-duty, daily cycling applications in competition with deregulated grid prices or reciprocating engine generators (GT7) • Very small gas turbines, 3 MW or less, are noticeably higher priced per kilowatt than competing reciprocating engines, due principally to low production volumes and low commonality of parts among multiple turbine models (GT7) • In sizes above 5 MW, gas turbines have an inherent economic advantage over reciprocating engines that they process more air per unit volume of machine, and their power generation efficiencies begin to approach those of reciprocating engines (GT7)

Source: Navigant Consulting, Inc.

Small Gas Turbines – Existing Research

PIER has funded several small gas turbine research projects. Table 24 below lists current research on small gas turbine technology.

Table 24. Small Gas Turbine Research

Existing Research– Small Gas Turbines	
US DOE / National Labs	• The US DOE's Distributed Energy Program sponsors programs and initiatives for the advancement of many DG technologies. In 2000, the US DOE spent $24 million on combustion turbine research (GT4) • ORNL investigated small gas turbines for CHP in a 2008 research report (GT11)
California / PIER	• PIER: Catalytic Combustor-Fired Gas Turbine for Distributed Power & Cogeneration. PIER Funding: $815,000 / Match Funding: $773,000. Develop the component technologies and engineering design of a multi-can catalytic combustion system for use in 5.2 MW and 4.6 MW gas turbines. (GT9) • PIER: Durability of Catalytic Combustion Systems. PIER Funding: $1,316,000 / Match Funding: $3,030,000. One-year reliability and durability demonstration of catalytic combustion technology on a 1.5 MW gas turbine. (GT9) • PIER: Catalytic Combustor-Fired Industrial Gas Turbine. PIER Funding: $3,000,000 / Match Funding: $1,623,000. Implement cost-effective, low-emission, catalytic combustion in a 5.3MW gas turbine (with applicability to a 4.6 MW turbine). (GT9)
Other States	• NYSERDA cost-shared a 5.5 MW Gas Turbine CHP System installed in 2004 at Turning Stone Casino (GT8)
Universities	• In 2003, University of California, Berkeley's Energy & Resources Group (ERG) received $300,000 from US DOE to study the feasibility of CHP for small businesses and encourage its use in commercial and industrial as well as residential settings. (GT10)
Private Sector	• Missouri Joint Municipal Electric Utility Commission (MJMEUC) and Missouri Ethanol, LLC, installed a 14.4 MW gas turbine CHP system in 2006 in the ethanol plant (GT6)

Source: Navigant Consulting, Inc.

3.1.2. Cooling

Key takeaways from profiles of absorption cooling technologies are:

- Absorption chillers are currently the primary technology used in CCHP systems.
- Electric driven chillers are another important technology used in CCHP systems.
- High cost, relative to the efficiency benefits, is the main barrier for wide-scale adoption of CCHP.
- While overall CHP efficiency is generally lower for systems paired with absorption chillers, the primary benefits of using the technology in warmer climates are around more effective usage of waste heat.

Absorption Cooling – Overview

Absorption chillers are most cost-effective in large facilities with significant heat loads. The most significant barrier to widescale adoption of absorption chillers is high cost of equipment. CCHP research involves pairing absorption chillers with reciprocating engines and microturbines. Research in creating prepackaged CHP systems with absorption chillers will reduce costs. Further research to improve efficiencies of CHP with absorption chillers is also needed.

Absorption Cooling – Description

The rejected heat from power generation equipment (for example, turbines, microturbines, and engines) may be used with an absorption chiller to provide the cooling in a CHP system. (AC1) An absorption chiller transfers thermal energy from the heat source to the heat sink through an absorbent fluid and a refrigerant. The absorption chiller accomplishes its refrigerative effect by absorbing and then releasing water vapor into and out of a lithium bromide or ammonia solution (AC7)

Commercially proven absorption cooling systems, ranging in size from 3 to 1,700 tons are widely available. These systems come as stand-alone chillers or as chillers with integral heating systems (AC5). Absorption chillers primarily use heat energy with limited mechanical energy for pumping. These chillers can be powered by natural gas, steam, or waste heat (AC7).

Efficiencies of absorption chillers are described in terms of coefficient of performance (COP), which is defined as the refrigeration effect, divided by the net heat input (in comparable units such as kBtu). Typically, COPs range from 0.65-1.2 (AC5). The greater the number of stages for absorption chillers, (single, double or triple-stage), the higher the overall efficiency of the chiller (AC7). In the CHP application, overall CHP efficiency decreases when paired with absorption chillers. One study found a decrease in system heating efficiency from 75 percent to 60 percent (AC 15). In southern climates absorption technology can increase the effective use of waste heat by 30 percent to 40 percent (of fuel input) in many building types (office, retail, etc) (AC6). Single-effect chillers can produce 70 to 80 percent as much cooling as double-effect when used with microturbines. While the COP of the double-effect machine can be twice that of single-effect, a single-effect machine can extract useful energy from the microturbine exhaust down to a much lower temperature (typical minimum activation temperature of 170°F versus 340°F) (AC3).

Absorption cooling minimizes or flattens the electric peaks in a building's electric load (AC5).

Sub-technologies of absorption chillers are:

- Absorption chiller systems are classified by single-, double- or triple-stage effects, which indicate the number of generators in the given system (AC7).
- Cooling technologies:
    - Lithium bromide-water absorption
    - Advanced ammonia-water absorption

Costs of absorption chillers vary based on the number of generators in use. Further, absorption chillers eliminate the use of chlorofluorocarbons (CFCs) in cooling systems. Table 25 below lists key characteristics of absorption chillers.

Table 25. Absorption Chillers Technology Characterization

Technology Characterization – Absorption Chillers	
Cost	Double-effect absorption chillers typically have a higher first cost, but a significantly lower energy cost, than single-effects, resulting in a lower net present worth (AC7) Absorption chillers generally become economically attractive when there is a source of inexpensive thermal energy at temperatures between 212°F and 392°F. (AC7) **Total Installed Cost** • Electric--$300/ton (AC6) • Single-Effect--$500/ton (AC6) • Double-Effect--$650/ton (AC6) • Additional Cooling Tower Cost for Absorption $50/ton (AC6) • Additional cost for waste heat recovery only for engine: $220/kW (AC6) • The target factory price for an ammonia-water absorption heat pump is ~$700/ton. End-user installed cost will be at least 2 times higher. This estimate is for commercial production volumes of 50,000 units per year and higher (AC6) **O&M Cost** • $10-30/ton annually, for single-effect chillers (AC8)
Emissions	• When combined with CHP systems, absorption chillers can increase energy efficiency dramatically, improve power reliability, and reduce greenhouse gas emissions (AC7) • Cool buildings without the use of ozone-depleting chlorofluorocarbons (CFCs) (AC7)
Benefits	• Can be modularized into larger systems (AC1) • The primary energy benefit of absorption cooling systems is reduction in operating costs by avoiding peak electric demand charges and time-of-day rates (AC5) • Elimination of the use of CFC and HCFC Refrigerants (AC5) • Quiet, vibration-free operation (AC5) • Lower pressure systems with no large rotating components (AC5) • High reliability (AC5) • Low maintenance (AC5) • Most cost-effective in large facilities with significant heat loads (AC7) • Waste-heat fired LiBr-Water absorption can improve DG economics, especially when DG electric efficiency is marginal (AC6)
Potential	• Machines based on aqueous lithium bromide are widespread today and account for approximately 5 percent of the U.S. commercial cooling market and as much as 50 percent of the markets in Japan, Korea, and China (AC1) • The most promising markets for absorption chillers are in commercial buildings, government facilities, college campuses, hospital complexes, industrial parks, and municipalities (AC7)

Source: Navigant Consulting, Inc.

Absorption Chillers – Adoption Barriers

Barriers to wide-scale adoption of absorption chiller technology are outlined in Table 26 below. The most significant barriers to wide-scale adoption of absorption chillers are high costs of equipment.

Table 26. Absorption Chillers Adoption Barriers

Adoption Barriers– Absorption Chillers	
Technology	• The key technical barrier to air-cooled operation is the increased tendency for LiBr solutions to crystallize in the absorber when heat-rejection temperatures rise (AC3) • Absorption systems also require greater pump energy than electric chillers (AC5) • Absorption chillers require larger cooling tower capacity than electric chillers, due to the larger volume of water (AC5)
Market	• Key factors in the lack of market success for air-cooled LiBr chillers/coolers are the general down turn in the overall absorption chiller market and the high projected costs for air-cooled designs (AC3) • High first cost (AC6) • Complicated economic story and utility rate uncertainty increases risk (AC6) • Not compatible for buildings which would conventionally be using unitary AC (water-cooled, cost higher for low capacities, perception of maintenance issues) (AC6) • None of the large U.S. HVAC industry companies are involved in ammonia-water absorption system development or manufacture (AC6) • Reality or Perception of flammability/toxicity issues with ammonia systems (AC6) • There is, however, another formidable design challenge for light-commercial CHP applications in the U.S., namely, operation at high ambient air temperatures (AC3)

Source: Navigant Consulting, Inc.

Absorption Chillers – Existing Research

Research is focused around pairing absorption chillers with microturbines. NYSERDA funds absorption chiller demonstration projects. Table 27 below lists current research on absorption chiller technology.

Table 27. Absorption Chiller Research

Existing Research– Absorption Chillers	
US DOE / National Labs	• US DOE's Energy Efficiency and Renewable Energy (EERE) program funds ammonia-water absorption chiller and heat pump development -- The objective of this project is to develop commercially viable thermally activated residential and light commercial cooling and heating appliances capable of using natural gas, propane, or on-site-generated exhaust heat as a primary energy source. (AC2) • US DOE's EERE program funds the Absorption Chillers for Buildings program to make chillers more efficient in their engineering and more prominent in the marketplace. One general goal is to compare thermally activated chillers with conventional heating, cooling, and air conditioning (HVAC) systems. (AC7) • Working with York International, the program is developing, testing, and marketing an advanced Double Condenser Coupled (DCC) commercial chiller, which is expected to be 50 percent more efficient than conventional chillers. The US DOE-patented DCC technology uses a LiBr/H20 refrigerant solution and is targeted for near-term commercialization. (AC7) • US DOE's Distributed Energy Resources program funded in 2002-2004 a Research, Development, and Demonstration of Packaged Cooling, Heating, and Power Systems for Buildings (BCHP) program. The program goal was to develop a waste-heat driven absorption chiller in a microturbine CHP system (AC10)
California / PIER	• Energy Commission funded DE solutions \$1.2 million of a \$2 million Cooling & CHP research project to create a pre-packaged CHP system with an absorption chiller and reduce installation costs of integrating it with the HVAC system. The project ran from 2004-2006. (AC11) • Energy Commission funded CMC Engineering \$1.5 million of a \$1.9 million Microturbine CHP Waste Heat project from 2004-2007 to create a pre-packaged CHP system with an absorption chiller and to develop a packaged boiler that supplies 80 kW of power. (AC11)
Other States	• In 2004, NYSERDA funded half of a \$1.12 million CHP with absorption cooling demonstration project (AC12) • In 2004, NYSERDA assisted in an installation of four reciprocating engines coupled with a 250 ton absorption chiller at an elementary school (AC13) • In 2001, NYSERDA provided \$300,000 to fund supplementing two of a hospital's electric chillers with a 400 ton absorption chiller and additional heat recovery equipment (AC14)
Universities	• In 2003, University of Maryland, partnered with ORNL, researched a 60 kW microturbine with a 20 ton absorption chiller. (AC9)

Source: Navigant Consulting, Inc.

3.1.3. Advanced Gas Turbine Cycles

The key takeaways from profiles on advanced gas turbines are:

- Most of the advanced gas turbine cycle technologies are mature, and most new power plant projects typically incorporate these technologies.
- There is a significant opportunity to improve efficiency from existing power plants by retrofitting them with advanced gas turbinecycle technologies.
- In recent years, there has been limited research on developing new gas turbine cycle technologies; most of the research in these technologies was performed over 10 years ago.
- There has been limited effort to demonstrate the benefits of the technologies in retrofit applications.
- Recent research has been primarily focused on materials, by the OEMs.
- There has been a significant amount of research outside the United States on hybrid renewable systems that address the intermittency of renewables.
- While there are significant incentives in place for renewable systems, hybrid systems do not qualify for these incentives, and there are few incentives available for hybrid renewable systems.
- There is a large technical potential for industrial cogeneration and heat recovery that has not been realized.

Industrial Cogeneration – Overview

Industrial cogeneration provides one of the most costeffective means to boost generation efficiency and reduce emissions. It is a mature technology that has been used for many years in industrial, large commercial, and institutional applications. There is a large technical potential for industrial cogeneration in California that has not been realized, but a barrier to industrial cogeneration is that Rule 21 applies only to DG up to 10 MW so many potential industrial cogeneration applications are still plagued by burdensome interconnection issues. Further, ambiguous tax depreciation policies may discourage industrial cogeneration project ownership arrangements, increasing the difficulty of raising capital and discouraging development. Improvement in the fuel flexibility and efficiency of industrial CHP systems is necessary to improve the life-cycle cost/benefit ratio of this technology. Because California state emissions regulations are so restrictive, near-term R&D needs to focus on low emission gas turbines and reciprocating engines and NOx emission controls for these technologies.

Industrial Cogeneration – Description

Industrial cogeneration (or CHP) is the combined production of electricity and useful heat energy from a single source of energy. In cogeneration waste heat from the electricity generation can be used in a direct heating or drying application; it can be used to produce hot water; it can be used in a heat recovery steam generator (HRSG) to create usable steam; or it can be used to provide energy for cooling. Gas turbines are ideally suited for CHP applications because their high-temperature exhaust can be used to generate process steam at conditions as high as 1,200 pounds per square inch gauge (psig) and 900 degree Fahrenheit (°F) or used directly in industrial processes for heating or drying. Gas turbines continue to be the preferred generation technology for CHP systems, representing 50-80 percent of annual additions since 1990.(FC9) A typical industrial CHP application for gas turbines is a chemicals plant with a 25 MWe simple-cycle gas turbine supplying baseload power to the plant with an unfired heat recovery steam generator (HRSG) on the exhaust. Approximately 29 MW thermal (MWt) of steam is produced for process use within the plant. A significant number of simple-cycle gas turbine-based CHP systems operate in a variety of applications including oil recovery, chemicals, paper production, food processing, and universities.(CO5) Simple-cycle CHP applications are most prevalent in smaller industrial installations, typically less than 40 MW.

Applications that use industrial cogeneration can run on a wide variety of fuels including biomass, digester gas, land fill gas (LFG), coal, natural gas, propane, fuel oil, kerosene, wood, and waste products (petroleum coke, blast furnace gas). Natural gas fules most of the industrial CHP in California (CO8).

The typical efficiencies for gas turbines in industrial CHP applications, assuming an unfired HRSG with exhaust temperatures of 280°F, producing dry, saturated steam at 150 psig, for variously sized systems are:

- Net electric efficiency (HHV) – 10MWe/14MWt gas turbine = 57 percent; 25MWe/26MWt gas turbine = 63 percent; 40MWe/38MWt gas turbine = 66 percent (CO5).
- Total CHP efficiency (HHV) – 10MW/14MWt gas turbine = 68 percent; 25MW/26MWt gas turbine = 71 percent; 40MW/38MWt gas turbine = 72 percent (CO5).

The applications for industrial cogeneration are vast, but it has the most potential in states with large industrial sectors, stringent air quality requirements, and effective policies to encourage adoption.(CO9) It can be used in the following industries: refining, food processing, oil/gas extraction, colleges and universities, pulp and paper, wood products, hospitals, chemical, military bases, airports, metal manufacturing, government buildings, warehouses, and mineral and glass manufacturing (CO8).

Industrial cogeneration provides one of the most cost effective means to boost generation efficiency and reduce emissions. The main benefits of industrial cogeneration are increased end-user reliability, potentially lower energy cost, and reduced emissions. Table 28 below lists the key characteristics of industrial cogeneration.

Table 28. Industrial Cogeneration Technology Characterization

<table>
<tr><th colspan="2">Technology Characterization – Industrial Cogeneration</th></tr>
<tr><td>Cost</td><td>The basic installation cost does not include extra systems such as the fuel-gas compressor, heat-recovery system, water-treatment system, or emissions-control systems such as selective catalytic reduction (SCR) or continuous emission monitoring systems (CEMS). The basic cost estimates do include dry low emissions (DLE) control, unfired heat recovery steam generators (HRSG), water treatment for the boiler feed water, and basic utility interconnection for parallel power generation. A complex installation might be what one would expect for a retrofit installation at an existing facility with access constraints, special customer conditions, and other factors. (CO5)
Total Installed Cost
• Basic Installation – 10MWe/14MWt gas turbine = 1300$/kW ; 25MWe/26MWt gas turbine = 1100$/kW percent; 40MWe/38MWt gas turbine = 970$/kW(CO5)
• Complex installation with SCR (for NOx reduction) and natural gas compression – 10MWe/14MWt gas turbine = 2000$/kW ; 25MWe/26MWt gas turbine = 1500$/kW; 40MWe/38MWt gas turbine = 1300$/kW(CO5)
O&M Cost
• 10MWe/14MWt gas turbine = 0.0070$/kWh ; 25MWe/26MWt gas turbine = 0.0042$/kWh; 40MWe/38MWt gas turbine = 0.0042$/kWh(CO5)
Incentives
• A 10 percent Federal ITC for the first 15MW of CHP up to 50MW has recently been enacted at the Federal level under the Energy Improvement and Extension Act of 2008. This ITC requires a minimum 60 percent efficiency and is valid through December 31, 2016.(CO:9,20)
• CHP units up to 10MW are covered under “Rule 21”—DG tariffs by the California Public Utility Commission. California was the first state to have a standard practice for interconnection for every utility in the state’s jurisdiction.(CO14)
• CHP systems meeting minimum thermal use and efficiency standards outlined by California Public Utilities Code Section 218.5 receive an incentive gas price based on the electric generation rate.(CO6)
Total Levelized Cost
These cost don’t include SGIP incentives.
• For 5-20 MW gas turbines net power cost: 7 ¢/kWh (CO6)
• For >20MW gas turbines net power cost: 6.5 ¢/kWh (CO6)</td></tr>
<tr><td>Emissions</td><td>It is important to note that the gas turbine operating load has a significant effect on the emissions levels of the primary pollutants of NOx, CO, and VOCs.(CO5)
CO2[13]
Assuming that the turbines operate on natural gas with a carbon content of 34 lb/MMBtu the CO2 emissions are: 10MWe/14MWt gas turbine = 750 lb/MWe; 25MWe/26MWt gas turbine = 675 lb/MWe; 40MWe/38MWt gas turbine = 650 lb/MWe(CO5)
Criteria Pollutants – Gas turbines are among the cleanest fossil-fueled power generation equipment commercially available. Many new gas turbines for industrial CHP applications feature lean pre-mixed combustion systems. These systems, sometimes referred to as dry low NOx (DLN) or dry low emissions (DLE), operate in a tightly controlled lean (lower fuel-to-air ratio) premixed mode that maintains modest peak flame temperatures. The most advanced commercial turbines for industrial CHP exhibit NOx emissions of 0.5-0.9 lb/MWh and CO emissions of 0.51-0.66 lb/MWh.(CO5) The use of SCR can further reduce NOx levels by 80-90 percent.(CO16) Furthermore, because of their high efficiencies CHP systems will use less fuel and emit less emissions than separate generation of electricity and thermal energy.(CO9)</td></tr>
</table>

[13] CO2 emissions calculations use the net electric efficiencies of the most current simple-cycle gas turbine industrial CHP systems.

Table 28. (Continued)

Technology Characterization – Industrial Cogeneration	
Benefits	**Energy Savings** - Overall CHP efficiency generally remains high under part load conditions. The decrease in electric efficiency from the gas turbine under part load conditions results in a relative increase in heat available for recovery under these conditions. This can be a significant operating advantage for applications in which the economics are driven by high steam demand.(CO5) Furthermore, because the overall efficiency of industrial CHP is so high it results in less overall fuel use and thus results in fuel cost energy savings. **Reduced Emissions** – Because of their high efficiencies industrial CHP systems will use less fuel and emit less emissions than separate generation of electricity and thermal energy.(CO9) Furthermore, many new gas turbines used for industrial CHP utilize emission reducing technology such as DLE and exhibit some of the cleanest emissions of any commercial generating technology. **Mature Technology** – CHP has been used for many years in industrial, large commercial and institutional applications. **Avoided Generation Costs** – A 2007 study by McKinsey & Company on reducing US GHG emissions shows that under proper market conditions, CHP can deliver CO2 reductions at a negative marginal cost for both the commercial and industrial sectors (CO2 abatement cost with industrial CHP = -15 $/ton). This means that investing in CHP generates positive economic returns over the technology's life cycle.(CO9) Additionally, since industrial CHP is located close to the point of consumption transmission and transformer losses are avoided and therefore less generation is required to meet load. **End-user Reliability** – Industrial CHP is capable of keeping facilities running when local or regional electrical grids fail. For an industrial manufacturing facility a 1 hour outage can cost the company over $50,000.(CO9)
Potential	In California there is over 3800 MW worth of simple cycle gas turbine CHP (>20MW) installed, and an additional 3200 MW worth of combined cycle CHP (>20MW) installed.(CO8) The remaining potential for "traditional" CHP in the industrial sector of California is 6418 MW (2005-2020). There is a total technical CHP "export" potential of 5,270 MW (2005-2020), this export potential describes the excess electricity that could be produced by the largest industrial facilities which exhibit large steam demands. Most of this export potential resides at facilities larger than 20 MW. (CO:6,7)

Source: Navigant Consulting, Inc.

Industrial Cogeneration – Adoption Barriers

Technology barriers have impeded full market deployment of industrial cogeneration systems. These barriers include system and component capital costs, emissions control, and fuel costs and flexibility (CO9). Major regulatory and market barriers to industrial cogeneration have also limited market deployment. These barriers include non-uniform interconnection standards, high system costs, and volatile gas prices. Other barriers to widescale adoption of industrial cogeneration technology are outlined in Table 29 below.

Table 29. Industrial Cogeneration Adoption Barriers

Adoption Barriers– Industrial Cogeneration	
Technology	**Performance** • Improving the energy and environmental performance of CHP and thermal energy recovery technologies (gas turbines, microturbines, engines, fuel cells, desiccants, chillers, and heat recovery systems) will significantly lower capital costs.(CO9) • Increasing fuel flexibility of combustion systems with no degradation of emissions profile, performance, or reliability, availability, maintainability and durability will reduce operating costs and fuel risk.(CO9) • Because California state emissions regulations are so restrictive, near term R&D needs to focus on low emission gas turbines and reciprocating engines and NOx emission controls for these technologies.(CO6) • Controlling all pollutants simultaneously at all load conditions is difficult. At higher loads, higher NOx emissions occur due to peak flame temperatures. At lower loads, lower thermal efficiencies and more incomplete combustion occur, resulting in higher emissions of CO and VOCs. Furthermore, achieving low levels of CO has become more difficult because techniques used to engineer DLN combustors had a secondary effect of increasing CO emissions.(CO5) **Reliability** • CHP system limitations with reliability, availability, maintainability, and durability that at times can adversely affect life-cycle costs. (CO9) **Other technology** • Improper installation or lack of coordination between developers and utilities in the planning and installation process of CHP systems can result in technical complications related to grid operations.(CO9) • Utilizing alternative fuels requires modifications to a CHP system's prime mover (for example,turbine, reciprocating engine, fuel cell, etc.). It also requires investment in fuel gathering, handling, treatment, and storage equipment, which often adds a parasitic load to the system. All of these elements affect the life-cycle cost/benefit analysis.(CO9) • Standardized fully integrated CHP systems could be further developed and the capital and installation costs could be reduced. (CO6) • Electric and thermal energy storage systems need to be integrated into CHP systems to increase the value proposition to end-users. (CO6)
Regulatory	**Interconnection Issues** • To be successful in the market, CHP systems must be able to safely, reliably, and economically interconnect with the existing utility grid system. The lack of uniformity in application processes and fees as well as the enforcement of current interconnection standards makes it difficult for equipment manufacturers to design and produce modular packages, and reduces economic incentives for onsite generation. Adoption of technical interconnection standards, including their application within interconnection agreements, varies by state, limiting industrial CHP's deployment.(CO9) **Permitting** • The Clean Air Act's New Source Review (NSR) is a permitting barrier to installation of CHP systems. NSR requires large, stationary sources of air pollutants to install state-of-the-art pollution control equipment at the time of construction or whenever major modifications are made that can increase net emissions. CHP systems increase the emissions of a facility but significantly reduce total gross emissions because of their high efficiencies.(CO9) **Other regulatory** • Rate structures that link utility revenues to kWhs-sold serve as a disincentive for utilities to encourage customer-owned industrial CHP.(CO9) • CHP systems do not fall into a specific tax depreciation category, and their depreciation periods can range from 5 to 39 years. These disparate depreciation policies may discourage CHP project ownership arrangements, increasing the difficulty of raising capital and discouraging development.(CO9) • Industrial CHP systems usually require back-up service from the utility. The structure and make-up of the charges for this service are usually a

	point of contention between the utility and the consumer and can create an unintended barrier to industrial CHP(CO9). • Renewable portfolio standards/energy efficiency resource standards that include CHP exist in only 14 states (CO9).

Table 29. (Continued)

Adoption Barriers– Industrial Cogeneration	
Market	**High cost** • Investment in industrial CHP is fundamentally a business decision; since industrial CHP systems cost more than a non-cogen turbine and represent a significant investment, the cost of the system must be justified by its benefits. To date the lack of cost-competitive options in this size range (5-40 MW) has been a barrier to adoption. Reducing operating cost and capital cost are key to reducing this cost barrier. • Financial incentives such as investment tax credits, production tax credits are needed to encourage the development of industrial CHP. • Payback times of longer than 3 years will limit adoption.(CO6) **Natural Gas Price** • Natural gas has been the fuel of choice for CHP. Natural gas prices have increased substantially and been highly volatile. This has contributed to the recent slow adoption of CHP systems.(CO9)

Source: Navigant Consulting, Inc.

Industrial Cogeneration – Existing Research

Research being carried out and planned focuses on making industrial CHP more efficient, clean, and fuel-flexible. Table 30 below lists current research on industrial cogeneration technology.

Table 30: Industrial Cogeneration Research

Existing Research–Industrial Cogeneration	
US DOE / National Labs	**US DOE/NETL** – Recently it released a funding opportunity that seeks applications for cost-shared research, development, and demonstration projects for combined heat and power (CHP) applications. They seek application for small (5kW to <1MW), medium (1 MW to 20 MW) and large (>20 MW) CHP systems, in addition to applications which will substantially improve the energy efficiency of the U.S. industrial sector through funding cost-shared R&D projects in developing innovative technologies which are: (1) highly efficient, (2) meet future emission requirements, and (3) replace or mitigate natural gas usage. Medium and large systems must have thermal efficiencies of ≥75 percent(HHV) and ≥80 percent(HHV) respectively, and NOx, CO, and VOC emissions of less than or equal to 0.07, 0.10, and 0.02 lb/MWh respectively (taking a credit of 1 MW-Hr for each 3.4 MMBtu of waste heat recovered). Potential fuel sources should include, but are not limited to: natural gas, landfill gas, digester gas, coal or biomass derived synthetic gas, oil field waste gas, waste heat sources, biomass or other alternative fuels. Approximately $15,000,000 of US DOE funding is expected to be available for new awards in FY 2009 and an additional $25,000,000 of US DOE funding is expected to be available for awards under this announcement in out years. (CO10) **US DOE Industrial Distributed Energy Program** - The Industrial Distributed Energy activity provides R&D cost-shared support for collaborative R&D to accelerate the deployment, testing, and validation of novel distributed energy applications for industry. They are sponsoring CHP R&D projects which are related to automated monitoring and control of CHP, small scale microturbine/chiller CHP systems, reciprocating engine CHP combined with gas clean-up and expanded fuel flexibility, and low-temperature waste heat adsorption chiller modules as well as sponsoring CHP integrated energy demonstration projects at major industrial corporations such as Frito Lay and IBM.(CO11) **US DOE Distributed Energy Program** – This program is sponsoring seven industry teams in cost-shared CHP demonstration projects. The projects all focus on small scale CHP systems (<5MW) however the lessons learned stand to benefit industrial CHP. All of the projects either demonstrate microturbine or adsorption chiller CHP technology.(CO12) They are also sponsoring eighteen application projects to support implementation of the CHP Roadmap in the areas of raising CHP awareness, eliminating regulatory and institutional barriers, and developing CHP markets and technologies.(CO13)
California / PIER	**PIER** – They have funded multiple reports on CHP market potential, policy options, and recommendations for adoption. In 2008 the Competitive Solicitation and Small Grants program awarded $3.8 million for combined heat and power (CHP) and combined cooling, heating, and power (CCHP) systems research.(CO21) Additionally the AG program has research plans to reduce the emission levels of industrial gas turbines emission levels to a point at least comparable to large gas turbines by preventing formation of pollutants as opposed to post-combustion cleanup.(CO22) **PIER** – ICF is completing an industrial CHP market potential study, where they have determined that the maximum potential for industrial CHP is 5,268 MW of electricity for export to the California power grid (CO23) **PIER –** ICF is also updating the 2005 EPRI study on CHP market potential (CO24)
Universities	**Institute of Electrical and Electronic Engineers (IEEE)** - Approved the IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems. The standard, which was reaffirmed in 2008, details the technical and functional requirements relevant to the performance, operation, testing, safety, and maintenance of the interconnection of distributed resources.

Inlet Cooling – Overview

Inlet cooling provides a cost-effective, energy-efficient, and environmentally sound way to enhance peak gas turbine capacity and efficiency in hot ambient conditions. Inlet cooling systems tend to be fundamentally limited by ambient conditions, and the cost-effectiveness of these systems also highly depends on ambient conditions. These systems can pose risks to the compressor section and other parts of the turbine. The lack of awareness about these systems and their benefits, in addition to dated negative perceptions, pose a large barrier to adoption. Of all the inlet cooling sub-technologies, fog intercooling shows the greatest promise in providing significant and cost-effective power boosts, even in high humidity conditions. There are a lot of unknown reliability, corrosion, and pitting risks associated with fog intercooling. The performance enhancement limits of fog intercooling need to be investigated further.

Inlet Cooling – Description

During hot weather, combustion turbines (CT) suffer degradation of turbine generation capacity and efficiency. The typical CT on a hot day produces up to 20 percent less power than on a cold day. This is because the output of a turbine depends on the mass flow though it, so at a given shaft speed hot air is less dense and therefore produces less power. The basic theory of inlet cooling is to cool the inlet air so it becomes more dense , increasing the mass flow and thus maintaining a high level of power output from the turbine. Additionally, the work to compress air is directly proportional to its temperature, so cooling the inlet air reduces the work of the compressor so there is more work available at the turbine output shaft.(IC1) Cooling the inlet air also has the secondary effect of increasing turbine efficiency.(IC2) This technology can be applied to industrial and utility power plants, CHP generation applications, and mechanical drive turbines.

Sub-technologies of inlet cooling are:

- Inlet Air Chillers – This technology includes various types of refrigerant type air chilling systems, ranging from compressor-type chillers to adsorption chillers, which use "waste" heat as an energy source for the chilling process (IC1).
- Evaporative Coolers – These coolers use the energy absorbed by water when it evaporates to cool inlet air. They typically consist of a wetted honeycomb-like pad of material (the medium) through which inlet air is pulled through. The inlet air is cooled as the water in the medium absorbs heat and evaporates (IC1).
- High Pressure Fogging – This is the most recent cooling technology and is similar to evaporative coolers in that they cool by evaporating water, but instead of using an evaporative medium, the water is atomized into billions of micro-fine fog droplets that evaporate quickly. Pressurized water is fed to fog nozzle manifolds, which are installed in the air stream (IC1).

- Fog Intercooling – This is an innovative application of high pressure fogging technology. The basic concept is to inject more fog into the air stream than will evaporate. Unevaporated droplets are carried into the compressor where they evaporate with the heat from compression further cooling the air. Since the energy to compress air is proportional to its temperature, the evaporation of fog inside the compressor can result in a substantial increase in the net output of the turbine.

The primary benefit of inlet cooling is an increased power output in hot ambient conditions; a secondary benefit is reduced emissions. Table 31 lists the key characteristics of inlet cooling.

Table 31. Inlet Cooling Technology Characterization

Technology Characterization – Inlet Cooling	
Benefits	**Increased Power Output -** The primary benefit of inlet cooling is that it allows the plant owners to reduce or prevent loss of CT power output, compared to the rated capacity, when ambient temperature rises above 59°F or if the plant is located in a warm/hot climate region.(IC2) **Reduced emissions** – A significant secondary advantage of inlet cooling technology is a reduction in turbine heating rate (compared to an uncooled system) in hot ambient conditions. A more efficient turbine operation translates to lower emission rates. Emissions reductions also result from the very high heat-rate peakers (consuming as much as 20,000 Btu/kWh operating on boilers and steam turbines), which are displaced by inlet cooling technology.(IC2) The amount of heat rate reduction depends on the ambient conditions and the temperature drop achieved by the cooling technology. **Reduced Fuel Costs–** Inlet cooling can increase the heat rate of turbines leading to improved fuel efficiency.(1) **Lower fuel costs** – More efficient turbine operation results in lower fuel costs. **Avoided peak-capacity costs** – If lost capacity due to increases in ambient temperatures needs to be made up, inlet cooling offers a much lower capital cost per MW capacity gain produced than installing another combustion turbine for peaking.(IC2) **Attractive Economic Return –** These systems exhibit fast capital cost payback (high return on investment) (IC:2,7)
Potential	This technology has market potential in areas which exhibit high or growing peak demand and/or in areas which exhibit high ambient temperatures.

Source: Navigant Consulting, Inc.

Inlet air chillers provide the largest potential power boost but also have the highest capital costs. The capital cost and O&M cost of air chillers are still lower than the costs of additional peaking gas turbines. Table 32 below lists the key characteristics of inlet air chillers.

Table 32. Inlet Air Chiller Technology Characterization

Sub-Technology Characterization – Inlet Air Chiller	
Description	**Cooling Potential –** The most powerful method of inlet air cooling. There are chillers capable of keeping inlet air at 45°F throughout the year. Overall they are capable of achieving greater drop in inlet air temperature than other technologies. (IC1) **Power Boosting Potential** • The amount of power boost that this technology provides depends on the ambient conditions (for example,temperature) and the design of turbine being cooled. Given hot ambient temperatures >85°F chillers can provide a 13-30 percent power boost. This power boost allows the turbine to operate at or above its rated capacity even after accounting for the large parasitic losses.(IC2)
Cost	**Total Installed Cost** The cost of these systems on a per kW enhancement basis also depends on ambient conditions and the design of the turbine being cooled. • At 87°F ambient temperature the cost for a air chiller system for a moderately sized turbine (40-80MW) is 90-190 $/kW turbine capacity enhancement in a hot environment(IC2) • The cost of this system averaged over a hot day is about 200-300 $/kW turbine capacity enhancement depending on the ambient conditions.(IC:5,7)
Emissions	Inlet air chillers are capable of achieving the highest reduction in emissions because they can decrease inlet temperatures the most. Decreasing inlet temperatures will decrease the heat rate of the turbine (especially compared to an uncooled turbine on a hot day) and therefore reduce fuel use and emissions. Decreasing temperatures from 100F to 45F can increase efficiency by 6 percent for a typical aeroderivative combustion turbine.(IC2)
Benefits	**Low O&M Cost –** This technology is capable of boosting power for one-tenth of the O&M cost of a gas turbine, but higher than all other cooling technologies.(IC:5,6,9) **Ambient Independent Performance –** Cooling potential is not restricted by ambient humidity and can increase turbine performance better than evaporative cooling and fogging systems.(IC:1,6)
Potential	The potential market for this technology is areas which not only exhibit high peak demand and hot ambient conditions, but areas which also exhibit high humidity.

Source: Navigant Consulting, Inc.

Evaporative coolers can provide a cost effective method to increase turbine output in hot, dry environments. Additionally, evaporative coolers are the most mature and most cost-effective inlet cooling technology. Table 33 below lists the key characteristics of evaporative coolers.

Table 33. Evaporative Cooler Technology Characterization

Sub-Technology Characterization – Evaporative Cooler	
Description	**Cooling Potential –** The amount of cooling this technology can achieve is dependent on the ambient temperature and humidity. Evaporative coolers can cool the inlet to within 85 percent to 95 percent of the difference between the ambient dry-bulb and wet-bulb temperature. Depending on the humidity, 10-25°F of cooling can be accomplished on a hot day.(IC:1,7) **Power Boosting Potential** The amount of power boost that this technology provides depends on the ambient conditions (for example,temperature and humidity) and the design of turbine being cooled. Given hot ambient temperatures >85°F chillers can provide a 8-17.5 percent power boost. This power boost allows the turbine to operate at or near its rated capacity.(IC2) **Applications –** Best suited for hot dry climates. On an overall basis, this is the most widely used technology.
Cost	**Total Installed Cost** • A system for a 25MW turbine costs about $125,000.(IC9) • The cost of this system averaged over a hot day is about 100$/kW turbine capacity enhancement depending on the ambient conditions. If the conditions are humid this cost can rise to above 300 $/kW(IC7)
Emissions	Evaporative coolers are capable of achieving a reduction in emissions because they can decrease inlet temperatures; decreasing inlet temperatures will decrease the heat rate of the turbine (especially compared to an uncooled turbine on a hot day) and therefore reduce fuel use and emissions. Decreasing temperatures from 100F to 59F can increase efficiency by 4 percent for a typical aeroderivative combustion turbine.(IC2)
Benefits	**Low Capital Cost –** The capital cost of this system is comparable to fogging (slightly lower) but is much cheaper than chillers.(IC2) **Low O&M Cost –** The O&M cost of this technology is the lowest among all of the technologies. It requires a media change every 3 years.(IC6) **Limited Power Interruption for Retrofit**– Quick delivery and installation time. Turbine downtime is 7-10 days.(IC6) **Improved Turbine Air Quality –** Operates as an air washer and cleans the inlet air.(IC6) **Simple Operation** – No integration with gas turbine control system is required; there is low risk for overspray, and potable water can be used.(IC9)

Source: Navigant Consulting, Inc.

High-pressure fogging provides power boosting potential and efficiency benefits that are slightly better than evaporative cooling. Although similar in cost to evaporative cooling, high-pressure fogging exhibits better performance. Table 34 below lists the key characteristics of high-pressure fogging.

Table 34. High-Pressure Fogging Technology Characterization

Sub-Technology Characterization – High Pressure Fogging	
Description	**Cooling Potential –** The amount of cooling this technology can achieve depends on the ambient temperature and humidity. Fogging systems can cool the inlet air by 95 percent to 98 percent of the difference between ambient dry-bulb and wet-bulb temperature and is, therefore, slightly more effective than the evaporative cooling. Depending on the humidity, 12-30°F of cooling can be accomplished on a hot day (IC:1,7). **Power Boosting Potential** The amount of power boost that this technology provides depends on the ambient conditions (for example,temperature and humidity) and the design of turbine being cooled. Given hot ambient temperatures >85°F chillers can provide a 9-18 percent power boost. This power boost allows the turbine to operate at or near its rated capacity (IC2). **Applications –** These systems have been installed on both base-loaded and peaking gas turbines and are used in both simple-cycle and combined-cycle plants.(IC1) Best suited for hot dry climates. On an overall basis, this is the second most widely used technology (IC2).
Cost	**Total Installed Cost** • A system for a 25 MW turbine costs about $75,000 (IC9). • The cost of this system averaged over a hot day is about 100$/kW turbine capacity enhancement depending on the ambient conditions. If the conditions are humid this cost can rise to above 300 $/kW (IC7).
Emissions	Fogging is capable of achieving a reduction in emissions because they can decrease inlet temperatures; decreasing inlet temperatures will decrease the heat rate of the turbine (especially compared to an uncooled turbine on a hot day) and therefore reduce fuel use and emissions. Decreasing temperatures from 100F to 59F can increase efficiency by 4 percent for a typical aeroderivative combustion turbine.
Benefits	**Low O&M Cost –** The O&M cost of this technology is lower than chillers. It requires nozzle replacement every 2 years (IC:6,9). **Low Capital Cost–** In the right conditions (hot and dry) this is a much cheaper inlet cooling option than chillers (IC2). **Limited Power Interruption for Retrofit** – Quick delivery and installation time. Turbine downtime is about 2-3 days (IC:6,9). **Comparative Performance Benefits –** Higher cooling efficiency in humid climates than evaporative coolers and achieve more cooling compared to evaporative coolers. They also exhibit lower energy demands than chillers (IC1). **Application Flexibility –** These systems exhibit the fastest start up times requiring only a few minutes to achieve full power boost (IC1).

Source: Navigant Consulting, Inc.

While the limits of this technology have not been fully studied, it shows great promise in providing large, cost effective power boosts even in high humidity. Fog intercooling is more ambient independent than evaporative and fogging systems and offers superior performance enhancement. Table 35 below lists the key characteristics of fog intercooling.

Table 35. Fog Intercooling Technology Characterization

Sub-Technology Characterization – Fog Intercooling	
Description	**Power Boosting Potential –** Theoretically it is possible to inject enough fog to cause a power boost that is as high as that obtained by air chillers. This is because in addition to gaining a power boost from cooling the inlet air, additional power boost is gained by substantially reducing the amount of energy required to compress air in the compressor. However, the limits of fog intercooling have not been fully investigated (IC1,9). **Applications –** This technology is in the commercial growth stage with over 60 fog systems with fog intercooling installed on turbines in the US to date.(IC1) Well suited for turbines in hot climates, these systems work equally well during moderate ambient conditions as well (IC7).
Cost	**Total Installed Cost** • A system for a 25 MW turbine costs about $375,000 (IC9). • The cost of this system averaged over a hot day is about 65-80$/kW turbine capacity enhancement depending on the ambient conditions. (IC7) If the conditions are humid this cost can rise to aboout100$/kW (IC8).
Efficiency	Fog intercoolers are capable improving (under moderate temperatures) or regaining efficiency by 1-3 percent efficiency (IC9), this efficiency gain will result in reduced emissions.
Benefits	**Low Capital Costs –** Theoretically capable of achieving similar power boost to air chillers at a fraction of the cost (IC1). **Low O&M Costs –** They require nozzle replacement every 2-3 years (IC9). **Ambient Independent Performance –** These systems are more independent of ambient conditions than fogging or evaporative coolers (IC9).
Potential	The market for this technology is similar to that of inlet air chillers; the market may even be more broad since these systems offer benefits even at moderate temperatures.

Source: Navigant Consulting, Inc.

Inlet Cooling – Adoption Barriers

If the risks of fog intercooling can be reduced, it will be the best alternative.(IC9) The main market barrier for these technologies is lack of awareness. Other barriers to widescale adoption of inlet cooling technology are outlined in Table 36 below.

Table 36. Inlet Cooling Adoption Barriers

<table>
<tr><th colspan="2">Adoption Barriers– Inlet Cooling</th></tr>
<tr><td>Technology</td><td>Performance
• For evaporative coolers and fogging systems, the amount of cooling they create is fundamentally limited by the amount of moisture present in the air. As a result their cooling potential is limited in humid areas to about 10 to 15°F (IC:1,6).
• Evaporative coolers and fogging systems have inherent limitations on potential capacity improvement (6).
• Evaporative coolers require about 30 minutes to achieve full power boost and therefore cannot provide maximum power for peaking turbines right away (IC1).
• Evaporative coolers consume large amounts of water.
• Chillers require startup time before coming online and therefore cannot provide maximum power for peaking turbines right away (IC1).
• Chillers have higher parasitic loads than the other technologies (IC:2,6).
• Gas turbine adjustments might be needed to adapt to new operating conditions for compressor and combustor when implementing fog intercooling (IC9).
Reliability
• Water striped from the medium of an evaporative cooler can cause fouling of the compressor blades (IC1).
• The medium of evaporative coolers require frequent replacement (IC1).
• If the water droplets in fogging and fog intercooling are too large they have the potential for erosion of the compressor section (IC:1,9).
• There are a lot of unknown reliability, corrosion, and pitting risks associated with fog intercooling.
Other technology
• Fogging, fog intercooling require integration with turbine controls system (IC9).
• Chillers exhibit a large footprint, bulky construction, and a water tower (IC9).
• Demineralized water is required with fogging and fog intercooling systems.</td></tr>
<tr><td>Market</td><td>High cost
• For inlet air chillers high first costs and high operating and maintenance costs are large barriers.(IC:1,6,9)
• For evaporative coolers the high cost of retrofitting and installing them is a barrier as they tend to require duct enlargement to maintain low air velocities (IC1).
Equipment supply
• Chillers have long delivery and installation times (IC6).
Other market
• Lack of awareness of the benefits of inlet cooling. In some cases it is still considered a new technology. This is combined negative stigmas resulting from with past problems with crystallization in air chiller systems</td></tr>
</table>

Source: Navigant Consulting, Inc.

Inlet Cooling – Existing Research

There is lack of government sponsored research into inlet cooling technologies. Table 37 below lists current research on inlet cooling technology.

Table 37: Inlet Cooling Research

Existing Research–Inlet Cooling	
Private Sector	Turbine Inlet Cooling Association (TICA) – promotes the development and exchange of knowledge related to gas turbine inlet cooling (TIC) for enhancing power generation worldwide. TICA members gather several times per year, usually at major industry conferences, to exchange ideas and conduct TICA business.

Source: Navigant Consulting, Inc.

Source: Navigant Consulting, Inc.

Recuperated Gas Turbine Cycles – Overview

The recuperated cycle gas turbines currently available exhibit higher efficiency and lower emissions than other simple-cycle turbines of a similar size (around 5MW). Large, high pressure gas turbines are generally not suited to use the recuperated cycle since the optimal pressure ratio (~10) of this cycle is too low for these types of turbines. Additionally this cycle cannot generally be retrofit to an existing turbine. Gas turbines that use this cycle produce less power and have less waste heat for CHP applications than comparable simple cycle turbines. Most microturbines use the recuperated cycle to achieve acceptable efficiency levels. There isn't an intense research effort into the recuperated gas turbine cycle underway; most of the current research focuses on more complex cycles such as the humid air turbine (HAT) cycle and the intercooled, recuperated, reheat cycle. The success of this cycle will rely on improving the cost, durability, and reliability of the recuperator section.

Recuperated Gas Turbine Cycles – Description

This advanced turbine cycle uses the turbine exhaust gas to preheat turbine inlet air after the air exits the compressor but before it enters the combustion chamber. The exhaust gas and turbine inlet air are run through a special heat exchanger, called a recuperator, where the exhaust gas transfers it heat to the inlet air. Preheating the inlet air increases the overall efficiency as less fuel is required to heat the gas to the proper turbine inlet temperature. The increased efficiency of the turbine cycle results in lower fuel costs, reduced exhaust emissions, and reduced cost of power compared to a simple-cycle.

Recuperated gas turbine cycles are used in micro (up to 1 MW) to small turbines (4-15MW) (RE:1,3,7). Large, high-pressure gas turbines are generally not recuperated (RE9). Solar's Mercury 50 (4.6 MW) recuperated gas turbine is available only in a natural gas-fired version, but there are plans for a dual-fueled version.(RE1) Honeywell's AGT1500 gas turbine runs on diesel, jet fuel, gasoline, and marine diesel.(RE15) Microturbines with recuperated cycles can run on natural gas, liquid fuels, propane, and low Btu gas.(RE7).

Approximately 1 percentage point efficiency improvement to simple-cycle per each ~70 °F increase in temperature (RE5) . The recuperated cycle can double the efficiency of microturbines compared to simple cycle (RE:7,12). This cycle results in a 13-27 percent increase in efficiency compared to simple cycle at optimum pressure ratio (RE11).

The efficiency of recuperated microturbines are ~23-29 percent (HHV) and up to 70-80 percent in CHP applications.(RE7) Solar's Mercury 50 exhibits an electrical efficiency of 38.5 percent and up to 70-90 percent in CHP applications. This efficiency rating is 6-8 percentage points higher than most turbines of this size (RE1).

Recuperated gas turbine cycles were implemented extensively in the 1950s and '60s to improve turbine efficiency from ~18 percent to ~23 percent. Today applications are restricted to medium and micro gas turbines (RE6,1). Almost all microturbines employ a recuperated cycle to achieve acceptable efficiency levels. The small turbines can be used in industrial cogeneration or CHP applications in addition to commercial CHP or building cooling heating and power (BCHP) applications. The AGT1500 is used to power the US M1 Abrams tank. Turbines such the AGT1500 have been proposed to be used as the propulsion plant for diesel locomotives to achieve lower emissions (RE14). Recuperated gas turbines are also being pursued as the turbines of choice for fuel cell/gas turbine hybrid systems (RE10).

The recuperated cycle is an intermediate step on the path to intercooled recuperated gas turbines and humid air turbines (HAT cycle) (RE:7,3). The primary benefits of the recuperated cycle are increased efficiency, reduced emissions, and lower fuel costs. Table 38 below lists the key characteristics of recuperated gas turbines.

Table 38. Recuperated Gas Turbine Cycle Technology Characterization

<table>
<tr><th colspan="2">Technology Characterization – Recuperated Gas Turbine Cycle</th></tr>
<tr><td>Cost</td><td>Total Installed Cost
• Installed cost for Mercury 50 = 1200-1300 $/kW (RE17)
• Target for microturbine systems = 500 $/kW(RE12)
Total Levelized Cost
• 7 cents/kWh (RE17)</td></tr>
<tr><td>Emissions</td><td>All emissions values depend on the efficiency of the device, the type of fuel used, and the loading.
CO2
CO2 emissions assume natural gas with a carbon content of 34 lbs/MMBtu is used.
• Microturbine: ~1450 lb/MWh and ~600lb/MWh in CHP applications.
• Solar's Mercury 50 : ~1100lb/MWh and ~550 lb/MWh in CHP applications.
Criteria Pollutants
• Microturbine with recuperation: NOx = 25-50 ppm(RE7). For a more complete analysis of microturbine emissions see the microturbine technology profile.
• Solar's Mercury 50: NOx = 0.12 kg/MWh (5ppm), CO = 10ppm, VOC = 10ppm(RE1). This turbine also employs a special ultra-lean premix combustion system.</td></tr>
<tr><td>Benefits</td><td>Reduced Costs of Power[14] – more efficient turbine operation and lower fuel costs translates into a lower overall cost of power.
Lower Fuel Costs – Because the recuperated cycle is more efficient than the simple-cycle, it results in lower fuel consumption per unit of power produced.
Reduced Emissions
• Recuperated cycle turbines exhibit lower emissions compared to simple cycle turbines because they are more efficient.
Recuperated cycle microturbines exhibit very low emissions without any type of after-treatment devices. Reciprocating engines on the other hand have trouble meeting NOx and particulate emissions standards.(RE12)</td></tr>
<tr><td>Potential</td><td>The target potential market for the small recuperated turbines are the industrial and commercial CHP markets, especially where fuel prices are high, emissions standards are strict, and the turbine is needed to provide a baseload.</td></tr>
</table>

Source: Navigant Consulting, Inc.

[14] Even though commercially available microturbines do not result in these benefits because their costs are too high and efficiency levels too low, if one was to compare a hypothetical microturbine that use a simple cycle to the current turbines that use a recuperated cycle, the current turbines would have these benefits over the non-recuperated turbines.

Recuperated Gas Turbine Cycles – Adoption Barriers

The most significant adoption barriers of this cycle for stationary power are lack of suppliers and the difficulty in retrofitting existing turbines. Other barriers to widescale adoption of recuperated gas turbine cycle technology are outlined in Table 39 below.

Table 39. Recuperated Gas Turbine Cycle Adoption Barriers

Adoption Barriers– Recuperated Gas Turbine Cycles	
Technology	**Performance** • The recuperated turbine cycle produces about 10 percent less power than a simple-cycle of the same compressor pressure ratio and turbine inlet temperature. This is because an inherent pressure drop is associated with the recuperator and with its connections to the engine and gas turbine exhaust.(RE6) • The exhaust of recuperated turbines gas turbines is lower in temperature, which can negatively impact CHP performance of the turbine.(RE6) • At a given peak temperature there is an optimum overall pressure ratio for the cycle, at higher ratios recuperation capability is reduced by the narrowing gap between exhaust temperature and compressor discharge temperature (this temperature rises with pressure ratio).(RE3) • The lower pressure ratios (10 or less) required by this cycle restrict its application to small and mid-sized turbines.(RE13) • The level of success in applying this technology has primarily been dictated by the cost and durability of the recuperator.(RE3) **Reliability** • Because recuperators are subject to large temperature differences, they are subject to significant thermal stresses. Cyclic operation in particular can fatigue joints, causing the recuperator to develop leaks and lose power and effectiveness.(RE16) **Other technology** • More advanced cycles such as intercooled recuperated, and humid air turbines (HAT) are being pursued over the simply recuperated cycle.
Market	**High cost** • Microturbines costs are too high for significant market penetration and the recuperators are the largest, and one of the most expensive components of these systems(accounting for 25 to 30 percent of the cost).(RE12) • The additional cost of the recuperator must be outweighed by the additional benefits of the recuperated cycle.(RE13) **Equipment supply** • Only one company offers a small-sized turbine (Solar's 4.6MW Mercury 50) for power applications that uses this cycle and there are no large turbines which utilize this cycle. • It is too complicated and expensive to retrofit this cycle for an existing turbine, a turbine must be specifically designed and built to operate using this cycle. **Other market** • Lack of awareness of the benefits of inlet cooling. In some cases it is still considered a new technology. This is combined negative stigmas resulting from with past problems with crystallization in air chiller systems.

Source: Navigant Consulting, Inc.

Recuperated Gas Turbine Cycles – Existing Research

Much of the research into recuperated gas turbine cycles focuses on its application in high-efficiency microturbines. Table 40 below lists current research on recuperated gas turbine cycle technology.

Table 40. Recuperated Gas Turbine Cycle Research

Existing Research – Recuperated Gas Turbine Cycle	
US DOE / National Labs	**ORNL** – In 2000 ORNL conducted a study into high-temperature materials for microturbine recuperators. They also investigated technology needs and development priorities for the production of cost-effective recuperators for high-efficiency microturbines. **US DOE Advanced Turbine System Program** – One of the fruits of this program was Solar's Mercury 50 recuperative cycle gas turbine. However, the focus of this program wasn't recuperative cycles. The focus was to foster the development of more efficient, cleaner, cost-effective, and reliable turbines using any technology suitable.
California / PIER	**PIER** – The program is funding a significant amount of microturbine R&D, which tends to use recuperated cycles; however there doesn't appear to be any research focused specifically on the cycle itself.

Source: Navigant Consulting, Inc.

Intercooled Recuperated Cycle – Overview

The intercooled recuperated gas turbine cycle (IRC) improves the efficiency of simple-cycle turbines more than the recuperated cycle and improves the power output of the turbine rather than reducing it. The latest commercial intercooled recuperated gas turbine is designed for use in marine propulsion applications, not stationary power applications. A barrier is that this cycle cannot be retrofit to an existing turbine; therefore entirely new turbines must be designed to specifically use this cycle. As a result of optimal pressure ratio of around 10, this turbine cycle is limited for use in small to medium-sized turbines (5-25 MW). There doesn't seem to be extensive research into using this cycle for stationary power applications, although microturbines using this cycle are being developed for vehicle applications and may have stationary applications as well. The addition of two high-temperature, high-pressure heat exchangers (recuperator and intercooler) to the turbine cycle adds significant cost and complexity to the cycle. The success of this cycle will rely on reducing the cost of these heat exchangers and proving the reliability of the cycle.

Intercooled Recuperated Cycle – Description

This advanced cycle uses intercooling and recuperation technology.(IR2) The intercooled recuperated (ICR) cycle uses two stage compression in which the air is cooled by an intercooler after exiting the first low-pressure compression stage before entering into the second high-pressure compression stage. Next the turbine inlet air is preheated using the exhaust gas just as it is in the recuperated cycle. This cycle improves the performance of turbines more than just the recuperated cycle because in addition to getting the efficiency improvement from the preheated inlet air, the work of compression is reduced by reducing the temperature of the air being compressed. Additionally, the energy lost from intercooling is then recovered by the recuperator.(IR2) The intercooler also enhances recuperator effectiveness, as the inlet temperature is reduced thereby increasing exhaust heat recovery.(IR3)

This cycle is used in small turbines (4-25MW) (IR:2,3). Large, high-pressure gas turbines are not suited for this cycle because this cycle operates best at lower pressure ratios. Whereas the recuperated cycle improved efficiency while decreasing the maximum power output, the ICR cycle improves both the specific power and efficiency of the turbine compared with the simple cycle.(IR2) At a turbine inlet temperature of 1100°F, the ICR cycle shows an improvement of 3 percentage points in efficiency compared to the recuperated cycle (IR2).

Early ICR turbines of the 1950s achieved efficiencies of 28 percent at turbine inlet temperatures of 815°F and a pressure ratio of 8. Considering the technological constraints and low temperatures of these turbines this was a large improvement over simple-cycles (IR2). The latest ICR (the 25MW Rolls-Royce WR-21) achieves an efficiency of 42 percent (IR2).

Because this cycle exhibits optimum pressure ratios of 10 or less, it is best suited for small to mid-sized turbines. The most suitable applications of turbines with these cycles are those that require low fuel use under varying loads, high efficiency, and low emissions. These ICR turbines are being used power the latest naval surface combat ships (IR3). Their low fuel use under varying loads makes them suitable for mechanical drive applications.

The most important characteristics of this cycle are the increased efficiency and power output, these characteristics lead to most benefits. Table 41 below lists the key characteristics of intercooled recuperated cycle technology.

Table 41. Intercooled Recuperated Cycle Technology Characterization

Technology Characterization – Intercooled Recuperated Cycle	
Emissions	All emissions values depend on the efficiency of the device, the type of fuel used, and the loading. **CO2** • ~1000 lb/MWh **Criteria Pollutants** • Because these systems tend to use natural gas and they exhibit high efficiencies the criteria pollutants will be low. Additionally these cycles will probably use advanced combustion technology such as lean premix combustion to control NOx.
Benefits	**Increased Turbine Output** – Because this cycle reduces the energy of compression, it results in an increase in turbine output compared to the simple cycle. **Reduced Costs of Power**– More efficient turbine operation and increased power output translate to lower fuel costs and lower overall cost of power. **Lower Fuel Costs** – Because the ICR cycle is more efficient than the simple-cycle, it results in lower fuel consumption per unit of power produced. The 25 MW Rolls-Royce WR-21 provides a 25-27 percent fuel savings under varying loads over simple-cycle turbines.(IR3) **Reduced Emissions –** The ICR cycle turbines exhibit lower emissions compared to simple-cycle turbines because they are more efficient. **Small Footprint –** Because the ICR cycle improves the specific power of turbines, an ICR turbine takes up a similar amount of space as a comparable simple-cycle turbine (IR:2,3).
Potential	The initial market for turbines with these cycles is marine propulsion. Once cost come down the market for these cycles will be similar to that of the recuperated cycle.

Source: Navigant Consulting, Inc.

Intercooled Recuperated Cycle – Adoption Barriers

The most significant adoption barriers of this cycle for stationary power are lack of suppliers and the high costs of the two heat exchangers. Other barriers to widescale adoption of intercooled recuperated cycle technology are outlined in Table 42 below.

Table 42. Intercooled Recuperated Cycle Adoption Barriers

Adoption Barriers– Intercooled Recuperated Cycles	
Technology	**Performance** • The exhaust of ICR gas turbines is lower in temperature, which can negatively impact CHP performance of the turbine. • The two heat exchangers (the intercooler and the recuperator) lead to pressure drops (IR2). • The lower pressure ratios (10 or less) required by this cycle restrict its application to small and mid-sized turbines (IR2). **Reliability** • The introduction of an intercooler and a recuperator adds complexity to the turbine cycle and can potentially decrease the reliability.
Market	**High cost** • The two heat exchangers lead to increased equipment costs.(IR2) • The additional cost of the recuperator and intercooler must be outweighed by the additional benefits of the ICR cycle. • Designing new turbines that use this cycle is very expensive because of the high pressure and high temperature materials and heat exchanger units that must be designed. **Equipment supply** • Rolls-Royce is the only major producer of commercial ICR turbines. The turbine it makes is for naval surface ship propulsion. • Capstone Turbine Technologies, Agile Turbine Technology & Brayton Energy are developing an ICR microturbine for vehicle use that may have stationary applications as well (IR4). • It is too complicated and expensive to retrofit this cycle for an existing turbine; a turbine must be specifically designed and built to operate using this cycle

Source: Navigant Consulting, Inc.

Intercooled Recuperated Cycles – Existing Research

The most extensive research into ICR has focused on its application in marine propulsion, there does not seem to be extensive research for its application in stationary power. Table 43 below lists current research on intercooled recuperated cycle technology.

Table 43. Intercooled Recuperated Cycle Research

Existing Research– Intercooled Recuperated Cycle	
US DOE / National Labs	**Naval Surface Warfare Center/French Navy/British Navy** – The latest ICR turbine (WR-21) was developed under a nine-year, $400 million contract by the NSWC with support from the British and French Navy. One of the goals of the R&D program was to decrease the total ownership cost of ship power plants through improved efficiency, fuel consumption, and maintenance and improved reliability.
Private Sector	**Joint Venture between Capstone Turbine Technology, Agile Turbine Technology & Brayton Energy –** In 2006 these companies formed a joint venture to the further development, production, marketing and sales of a family of inter-cooled recuperated gas turbine commercial vehicle engines, the first of which will be called the ICR 225. This unit will be designed to provide 225kW – 75 kW of power at up to 42 percent efficiency, with negligible particulate emissions and only 0.06-0.13 kg/MWh NOx emissions. Though the initial design of the ICR 225 is for transportation uses, it may also be adapted for used in the stationary market (IR4).

Source: Navigant Consulting, Inc.

Heat Recovery – Overview

If moderate waste heat cannot be used within the process itself or within the plant boundaries, heat recovery becomes a clean, cost-effective, and attractive method to use waste heat to produce 2-6.5 MW of power. The technology behind heat recovery is mature, and the barriers to adoption are mostly market-based. Even though the economics and operation of these systems resemble renewable projects (large upfront cost, minimal fuel costs), they lack similar incentives necessary to encourage adoption. There is a large unrealized technical potential for the production of electricity from heat recovery in California. Successful implementation of this technology is highly site-specific; limited target market characterization and uncertain waste heat temperature and throughput have slowed adoption.

Heat Recovery – Description

Heat recovery is the process of using waste heat from various sources such as geothermal, industrial processes, and power applications, to generate additional electricity. There are a number of different cycles that can be used to turn the waste heat into electricity. Two advanced heat recovery cycles include the organic Rankine cycle and the Kalina cycle. These systems do not use fuel as they run on waste heat. The net efficiency of these systems in converting waste heat to electric power is 8-17 percent.

Potential applications for heat recovery will exhibit a relatively moderate waste heat stream temperature (at least 200°F, but >600°F is preferred) at a constant or predictable value that is relatively clean and contamination-free. Additionally the application will probably exhibit an inability to find or justify the use of waste heat within the application or heating equipment itself, and an inability to find or justify alternate heat recovery methods within the plant boundaries (plant utilities, steam, hot water, cascading, etc.).(HR11)

Sub-technologies of heat recovery are:

- **Organic Rankine Cycle** – In the organic Rankine cycle (ORC), superheated, high-pressure vapor is generated in a boiler and then expanded in a turbine. The turbine drives a generator to convert the work into electricity. This process involves a closed-loop cycle, allowing the continual reuse of the working fluid. The detail that makes it a organic cycle, as opposed to simply a Rankine cycle, is that it uses organic working fluids such as pentane or butane instead of water and steam. The organic Rankine cycle is effectively a refrigeration unit working in reverse, using the expanding working gas to power a scroll expander (compressor) (HR1).
- **Kalina Cycle** – A closed-loop process used for heat recovery that uses a working fluid composed of water and ammonia. By varying the ratio of this mix, the fluid's boiling point can be controlled (known as temperature glide) to provide higher levels of exergy. Because ammonia has a much lower boiling point than water, the Kalina cycle is able to begin spinning a steam turbine at much lower temperatures than typically associated with the conventional steam boiler/turbine systems (HR7).

ORC heat recovery systems can provide 30 kW to 6 MW of energy with absolutely no emissions. ORC heat recovery systems are a relatively mature technology, with a significant market, and an attractive likely levelized cost of electricity (LCE). Table 44 below lists the key characteristics of organic Rankine cycle technology.

Table 44. Organic Rankine Cycle Technology Characterization

Sub-Technology Characterization – Organic Rankine Cycle	
Description	**Size –** Sizes range from 30 kW to 6 MW (HR4). **Fuel –** These systems do not use any fuel, they run on waste heat. ORC cycles can generally recovery waste heat at minimum temperatures of about 200-300°F, but there are systems that can use temperatures as low as 165°F. **Efficiency –** These systems are able to recover about 8-15 percent of the energy in the waste heat (HR:4,12). **Applications –** Heat recovery using ORC has target applications in the following industries: food processing, cement, refineries, oil & gas extraction, and pipeline compressor stations. This cycle can also be used to recover waste heat from solar heat power plants and 1-15 MW distributed power generators as well (turbines, fuel cells, reciprocating engines).(HR4) It has an established reputation in the geothermal sector (HR5).
Cost	**Total Installed Cost** • 2,500-3500 $/kW capacity (HR:4,12). **O&M Cost** • 47-98 $/kW/yr (HR4). **Incentives** • Economics of the projects are still very typical of renewable energy projects (large upfront costs, minimal fuel costs), however no subsidies or tax breaks are applicable. • California does not provide any incentives to encourage this technology even though it has a very high upfront cost. • Stakeholders are looking to lobby for "renewable" status, as well as investigating the economic feasibility of using RECs or other GHG credits to improve the bottom line (HR4). **Total Levelized Cost**[15] • ≤ $70/MWh.
Emissions	There is no combustion, no fossil fuels are used, the whole system is a closed loop self-contained system,so all electricity generated is emission-free.

[15] Levelized cost of electricity assumptions: 12-year lifetime (discounted from ElectraTherm's claim of 20 years), 12-year loan period, and 7.49 percent rate (E3 Calculator); $2,529/kW first cost; $47/kW/yr O&M (ElectraTherm), 10.09¢/kWh avoided cost of electricity (EIA, 2006).

Table 44 . (Continued)

Sub-Technology Characterization – Organic Rankine Cycle	
Benefits	**High Technical Potential –** Accepts and rejects heat over a broad temperature range (temperature glide).(5) Has an attractive technical potential of 13-20 Mth/yr.(HR4) **Low production costs –** Generation units using the organic Rankine cycle are able to use off the shelf standard components (similar to those found in refrigerators) for the majority of the appliance, leading to low production costs.(HR:1-3) Additionally it utilizes readily available working fluids. **Low levelized cost of electricity–** The LCE is likely to be under $70/MWh.(HR4) **Reliability –** Generation units using the organic Rankine cycle are expected to have long lifetimes. One manufacturer claims a lifetime of 20 years.(HR4) **Mature technology** – This cycle has an established reputation in the geothermal sector. Because this cycle uses many components from traditional refrigeration appliances, it is a well-understood technology and there are several existing installations.(HR4) **Developed supplier base** – Five vendors offer this technology: UTC, Ormat, ElectraTherm, WOW Energies, and Barber-Nichols. UTC and Ormat are trusted brands. Some vendors already have existing relationships with California industry.(HR4) **Reduced emissions** – This technology has no emissions and it improves the efficiency of its parent process
Potential	California Technical potential = 13-20 Mth/yr. The potential market segments included in this range are the food processing industry, cement manufacturing, oil refineries, oil and gas extraction, and pipeline compressor stations.(HR4)

Source: Navigant Consulting, Inc.

The Kalina cycle can provide 2-6.6 MW of power, with no emissions, for a wide range of processes and applications. The Kalina cycle has the potential to be more efficient and cost-effective than ORC; however the technology is not as developed. Table 45 below lists the key characteristics of Kalina cycle technology.

Table 45. Kalina Cycle Technology Characterization

Sub-Technology Characterization – Kalina Cycle	
Description	**Size –** Sizes range from 2.0 MW to 6.5 MW (HR5). **Fuel –** These systems do not use any fuel, they run on waste heat. Kalina cycles can recovery waste heat at minimum temperatures of about 200°F up to temperatures of about 930°F. **Efficiency –** The thermal efficiency improvement provided by using the Kalina Cycle is up to 20 percent for high temperature heat sources and up to 40 percent for low heat energy sources (150-200°C).(HR:6,10) This cycle is 15-25 percent more efficiency than the ORC at the same temperature.(HR12) The net electrical efficiency of the Kalina cycle is between 12 percent and 17 percent; the gross electrical efficiency is between 14 percent and 19 percent (HR9). **Applications –** Heat recovery using Kalina cycles have applications in the following target waste heat industries: gas compressor stations, metal, glass, cement, chemical, and incineration plants, diesel plants, geothermal and solarthermal plants, pipelines, and gas turbines.(HR5) There have been three demonstration projects using the Kalina cycle. In general, the Kalina Cycle System 11 (a system that most suited for low-temperature geothermal plants) has better overall performance at moderate pressures than that of the organic Rankine cycle (HR11).
Cost	**Total Installed Cost** • Typically lower than ORC cycle.(HR5) It is likely that Kalina plants will cost less than Rankine cycle (water/steam) plants, with up to 30 percent savings for low temperature applications and 10 percent savings for high temperature applications (HR10). • 2000-3000 $/kW capacity (HR12). **Incentives** • Economics of the projects are still very typical of renewable energy projects (large upfront costs, minimal fuel costs), however no Federal or California subsidies or tax breaks are applicable.
Emissions	There is no combustion. No fossil fuels are used. The whole system is a closed-loop, self-contained system, so all electricity generated is emission-free (HR6).
Benefits	**Lower capital cost –** The Kalina cycle working fluid exhibits excellent thermodynamic and transport properties, better than hydrocarbons (HR:5,10). This means that the size and cost of heat exchangers will be less. Additionally it uses a readily available working fluid (water & ammonia) and off the shelf, commonly used hardware components (HR5). All of these features contribute to potentially lower future capital costs compared to ORC. **Higher relative efficiency –** Compared to ORC, the Kalina cycle is 15-25 percent more efficient at the same temperature. **Limited R&D Needed –** Since no special materials required for ammonia-water mixtures there isn't a need for advanced material research; in general there are no major equipment developmental hurdles (HR10). **Application Flexibility –** Accepts and rejects heat over a broad range of temperatures (temperature glide).(HR5) This allows the cycle to be used in a broad range of applications. **Reduced emissions/low environmental impacts –** This technology has no emissions; it improves the efficiency of its parent process, and in the event of an accidental system leak, ammonia is considered a biodegradable fluid (HR6).
Potential	The market potential for the Kalina cycle is similar if not greater than that of the ORC since it is a more efficient process, will likely cost less, and can be used over a similar temperature range. However, this technology is not as developed as the ORC, so its penetration may be delayed compared to ORC.

Source: Navigant Consulting, Inc.

Heat Recovery – Adoption Barriers

The most significant barriers for heat recovery are the high upfront costs, lack of incentives, and uncertain market potential. Other barriers to widescale adoption of heat recovery technology are outlined in Table 46 below.

Table 46. Heat Recovery Adoption Barriers

Adoption Barriers– Heat Recovery	
Technology	**Performance** • Heat recovery cycle technology is highly site-specific (HR4). • The Kalina cycle has failed to reach commercial success over a 20-year period due to the fact that ammonia cannot be separated from steam; if this problem can be solved, then technology becomes very competitive with Organic Rankine Cycle (HR5). • The Kalina cycle is complex to operate since water/ammonia proportions must be continuously varied according to ambient and heat source temperatures. **Reliability** • The Kalina cycle has a total evaporation step (100 percent evaporation of working fluid), which leads to corrosion from dissolved solids (HR5). **Other technology** • ORC's large footprint may pose a barrier (HR4). • ORC's may have environmental impacts and restrictions by using organic substances. • The Kalina cycle exhibits high cost and complexity due to equipment necessary to provide glide-matching; water/ammonia proportions must be continuously varied according to ambient and heat source temperatures to achieve optimum cycle efficiency (HR5).
Regulatory	Regulatory barriers of this technology will likely be similar to DG technologies. **Interconnection rules** • California interconnection requirements may pose a barrier.(HR4) **Other Regulatory** • Does not qualify for incentives which are typical of renewable energy projects.(HR4)
Market	**High cost** • ORC's high capital cost and buyback periods of 3-5 years may limit market penetration.(HR4) • Kalina cycle system's high capital costs and buyback period of 5-7 years may limit market penetration.(HR5) • ORC has significant cost uncertainty due to limited experience and site-specific nature of the technology.(HR4) • A large percentage of the Kalina cycle cost stems from the heat exchanger costs.(HR12). **Equipment supply** • ORC vendors are not currently interested in the California market because they are uncertain of the California market potential, there is no Renewables Portfolio Standard (RPS) or Renewable Energy Credit (REC) credit, and there is uncertain economic value (HR4). **Other Market** • Limited target market characterization; waste heat temperature and throughput uncertain (HR4).

Source: Navigant Consulting, Inc.

Heat Recovery – Existing Research

Aside from research in the private sector, there has been very little R&D or demonstration projects that specifically address heat recovery cycles. Table 47 below lists current research on heat recovery technology.

Table 47. Heat Recovery Research

Existing Research– Heat Recovery	
US DOE / National Labs	**US DOE** – In 1994 the US DOE awarded Exergy a $7 million grant for a geothermal Kalina cycle plant in Steamboat, Nevada.(7) **US DOE Geothermal Technologies Program** – This program has the broader goal of tapping into geothermal power for electricity, space and water heating needs. Some of the funding opportunities however, could be used to advance hear recovery cycle technology. For example,the Recovery Act: Geothermal Technologies Program has funding up to $350 million and one of the topic areas is Geothermal Energy Production from Low Temperature Resources, Coproduced Fluids from Oil and Gas Wells, and Geo-pressured Resources. The Enhanced Geothermal Systems Demonstration program has $49 million in funding and seeks projects in a variety of geologic formations which will quantitatively demonstrate and validate stimulation techniques that successfully sustain sufficient fluid flow and heat extraction rates for 5-7 years and produce at least 5 MWe per year per project site or geothermal reservoir.(HR14) **US DOE Industrial Technologies Program, Energy Intensive Processes** – They are funding GE to research to modify and optimize the ORC for industrial heat recovery. The research team will leverage previous research in advanced ORCs to develop a new direct evaporator technological solution that will reduce the ORC cost by up to 20 percent, enabling the rapid adoption of ORCs for industrial engines and turbines (HR15).
California / PIER	**California Energy Commission Energy Technology Advancement Program** – In 1992, the ETAP awarded $2.25 million to co-fund a pilot Kalina cycle plant in Canoga Park, California. Under the terms of a royalty agreement, Exergy will pay back total royalties of $6.75 million over a period based on its gross revenues. The plant operated until 1997. **PIER Energy Innovations Small Grants Program** – In 2008 it distributed $1 million worth of grants for waste heat recovery from industrial processes in California (HR13).
Universities	**Oregon Institute of Technology Renewable Energy Center –** The purpose of the waste heat power generation lab at OIT is to demonstrate and perform applied research on low temperature waste heat recovery systems. The center has produced a number of small lab bench waste heat engines.
Other Countries	**GERD** – Owned by NEDO (Japan's Department of Energy) as well as 18 major Japanese corporations, including the country's largest electric utilities and industry groups such as Sumitomo and Mitsubishi, GERD is a leader in Japan's efforts to develop and deploy advanced renewable energy generation technology. Recurrent Engineering is executing engineering contracts with GERD for a pre packaged design to generate power from remote low temperature hot springs using the Kalina cylce.
Private Sector	**United Technologies (UTC)** – Their PureCycle280® system (ORC) is a closed-cycle process that uses water to generate 225 kW of net electrical power. The system is currently available, and they have two demo projects in Alaska (HR4). **Ormat** – The Ormat Energy Converter (OEC) utilizes a hermetically sealed organic Rankine cycle generating system, which contains only one smoothly rotating part—the shaft driving the turbine's alternator rotor. It will provide 0.2 MW to 6 MW of continuous electrical power with minimal maintenance or repairs. They have installations worldwide and several in Southern California (HR4).

Source: Navigant Consulting, Inc.

Advanced Simple-Cycle for Peaking – Overview

Advanced simple-cycle turbines offer high efficiency and high reliability operation and feature fast start-up times and low emissions, which make them ideal for use as clean, peaking to mid-range dispatch generators. Advanced simple-cycle turbines can incorporate advanced cycle technology to enhance their performance such as intercooling, recuperation, inlet cooling, reheat, and steam injection. Commercially available advanced simple-cycle peaking turbines have high, proven availabilities and reliabilities. The high cost of these turbines compared to baseload technologies limits their broader adoption for power generation. Lack of fuel flexibility for these turbines is a significant barrier to adoption. Most of these turbines use natural gas, and the perceived scarcity and volatility of this fuel source can limit adoption.

Advanced Simple-Cycle for Peaking – Description

Advanced simple cycle peaking turbines are latest generation turbines characterized by high turbine inlet temperatures (1280-1500°C), high pressures (pressure ratios of 30-60), and high efficiencies. They are moderate in size (generally <100 MW) and exhibit high reliabilities and availabilities as well as quick start-up and ramp-up times. They commonly incorporate aero-derivative technology in addition to the most advanced large-frame-based technologies. These turbines can incorporate advanced cycle technology to enhance their performance such as intercooling, recuperation, inlet cooling, reheat, and steam injection (SC3).

Typically, these turbines generate 40-100 MW. The GE LMS100 can burn natural gas or distillate fuels. The Siemens LGT6-5000F can operate on natural gas, LNG, syngas, and high hydrogen content fuel (SC10). Alstom advanced turbines can operate on diesel oil, high hydrogen content synthetic fuel, blast furnace gas, and natural gas. Cycle efficiencies are 38-46 percent (HHV). The efficiencies of these turbines are still lower than combined-cycle plants based on large-frame industrial gas turbines (SC3). If used in a CHP application, these turbines could reach more than 85 percent thermal efficiency (SC2).

The primary applications envisioned for these types of turbines are peaking and mid-range dispatch power generation. Other possible applications for these turbines include CHP and using them in coal plants as a boiler feedwater heat source to boost overall efficiency (SC2).

Advanced simple-cycle turbines offer cutting edge performance and operational flexibility at a competitive cost. The primary benefits of advanced simple-cycle turbines are excellent reliability and availability, operational flexibility, high efficiency operation, and low emissions. Table 48 below lists the key characteristics of advanced simple-cycle technology.

Table 48. Advanced Simple Cycle for Peaking Technology Characterization

Technology Characterization – Advanced Simple Cycle for Peaking	
Cost	**Total Installed Cost** • 1300-1580 $/kW (SC7) **O&M Cost**[16] • Variable = 3-4.5 $/MWh(SC:8,9) • Fixed = 0.75 $/MWh(SC8)
Emissions	**CO2**[17] • 920-1100 lb CO2/MWh. **Criteria Pollutants**[18] • Because of their high efficiencies, use of natural gas, and lean premixed combustion systems (DLN/DLE), which pre-mix the gaseous fuel and compressed air so that there are no "hot spots" where high levels of NOx would form, these turbines exhibit low criteria emissions. The GE LSM100 has a NOx emissions of 25 ppm. The Siemens SGT6-5000F has NOx and CO emissions of <9ppm.(SC10) In general these turbines have NOx emissions of <25ppm.
Benefits	**Operational Flexibility –** The same characteristics that make these turbines suited for peaking applications – high efficiencies, low emissions, fast start-up and cool-down times, cycling capabilities, load-following capabilities, low fuel consumption, and fuel flexibility – also give them good operational flexibility. System Reliability – Advanced peaking turbines such as the Siemens SGT6-5000F have over 180 peaking units in operation with 2.5 million cumulative operating hours, demonstrating an availability of 95 percent and reliability of 99 percent.(SC10) The GE LMS100 has a target availability and reliability of 97.5 percent and 98.5 percent respectively. Many of these turbines exhibit modular designs that allow for rapid maintenance with minimal downtime. In general reliability and availability of these turbines are greater than 95 percent. **Low Emissions –** Using these high-efficiency, low-emission turbines in peaking applications will contribute to low marginal emission rates. **Energy Saving –** These advanced turbines exhibit high efficiencies over broad load profiles, leading to energy savings.

Source: Navigant Consulting, Inc.

16 Based on the O&M cost of GE's LMS100 and LM6000.

17 Based on an a turbine operating on natural gas with an assumed carbon content of 34lb/MMBtu.

18 Emissions are based on natural gas-fired operation.

Advanced Simple Cycle for Peaking – Adoption Barriers

The most significant barriers to adoption are volatile natural gas prices since many of these turbines operate on natural gas. Other barriers to widescale adoption of advanced simple-cycle technology are outlined in Table 49 below.

Table 49. Advanced Simple-Cycle Adoption Barriers

Adoption Barriers– Advanced Simple Cycle for Peaking	
Technology	**Performance** • Due to the strict emissions standards in certain areas, advance simple-cycle turbines would be restricted as to how many hours a year they could operate unless a costly SCR system was installed (SC8). • Lack of fuel flexibility, many advanced turbines for peaking operate on natural gas.
Market	**High cost** • The high cost of these turbines compared to baseload large-frame turbines limits their broader adoption as a baseload generating technology. **Natural Gas Volatility and Availability** • The potentially volatile nature of the natural gas market and the limited availability of natural gas research limit the market adoption of all gas turbines.

Source: Navigant Consulting, Inc.

Advanced Simple Cycle for Peaking – Existing Research

The most significant research into advanced simple-cycle turbines is being conducted by private companies. Table 50 below lists current research on heat recovery technology.

Table 50. Advanced Simple Cycle Research

Existing Research–Advanced Simple Cycle for Peaking	
US DOE / National Labs	**US DOE Advanced Turbine Systems** – This program has focused research on creating highly efficient and clean advanced baseload turbines such as the Siemens W501G and the GE H System Turbine. However, they have also funded research that can be incorporated into advanced gas turbines for peaking, which can make them more efficient and clean. For example, they funded ($900k) a project to develop a catalytic pilot technology that will make feasible simultaneous achievement of higher efficiency and ultra-low NOx for natural gas turbine engine systems operating with reduced after treatment requirements, or without SCR after treatment. They also funded ($1.5 million) a project to develop a prototype combustor that will reduce smog-causing nitrogen oxide emissions by 50 percent or more compared to state-of-the-art lean premixed gas turbine combustors (SC14). **NETL** – Although the Turbine Program goals are geared toward IGCC plants, oxy-fuel turbines, hydrogen turbines, and CO2 compression, they have completed research that can contribute to advanced simple-cycle turbines for peaking. In October 2003, NETL entered into a Cooperative Agreement (NETL share $250k) with General Electric Power Systems to achieve low-NOX emissions in a fuel flexible gas turbine through the integration of fuel composition control and combustor design. In September 2003, NETL entered into a cooperative agreement (NETL share $250k) with Siemens Westinghouse Power Corporation to develop and demonstrate a cost effective catalytic based turbine combustor for a fuel-flexible turbine. In September of 2003, NETL entered into a cooperative agreement (NETL share $107k) with Pratt & Whitney to conduct research and development of rich catalytic combustion technology for rapid deployment in industrial gas turbines. The resulting combustion systems will provide fuel flexibility for gas turbines to burn coal-derived synthesis gas or natural gas and achieve cost-effective, ultra-low NOx emissions, without exhaust stack cleanup (SC15).
California / PIER	**PIER** – PIER has sponsored a number of research projects on advanced simple-cycle turbine designs. For example, a 2005 project investigated the potential of an innovative gas turbine cycle using augmented combustion inside the turbine (turbine-burner) and heat regeneration for electricity generation. This turbine was designed for increased efficiency and power. A 2001 study investigated improved operational turndown of an ultra-low emission gas turbine combustor. The emissions targets for this design were sub-5 ppm NOX (referenced to 15 percent O2), sub-10 ppm CO and sub-10 ppm unburned hydrocarbons under partial load operating conditions.

Table 50. (Continued)

Existing Research–Advanced Simple Cycle for Peaking	
Private Sector	**Siemens –** The SGT6-5000F is Siemens 200MW advanced simple cycle turbine for peaking. It is a proven (2.5 million hours) large frame design that exhibits high efficiency (38.1 percent), low emissions, high reliability, and availability (99 percent and 95 percent respectively), and high operational flexibility (load following, cycling, and quick start capabilities). The SGT6-5000F provides economical, rapid on-line generation for peaking duty, intermediate operation, or continuous service. **GE –** The LMS100 aero-derivative/large frame hybrid design turbine represents GE's latest advanced simple-cycle peaking technology. This 100MW turbine exhibits extremely high efficiency (46 percent) and low emissions and is the first commercial turbine to use intercooling. It has very high operational flexibility and can reach full power in 10 minutes. Because of its high operational flexibility, this turbine can also serve mid-merit and baseload applications. Its modular construction allows for replacement of components without complete disassembly. The LM600 aero-derivative 44MW gas turbine is their other advanced simple-cycle turbine for peaking (over two-thirds of the installed turbines are serving peak load). It also exhibits high efficiency (38 percent) , low emissions, and a modular design. This turbine is well-proven in the field with over 10 million operating hours and an availability of 97.7 percent. **Alstom –** The 56MW GT8C2 and 115MW CT11N2 gas turbines are Alstoms advanced simple-cycle turbines for peaking. The Alstom GT8C2 gas turbine is designed for operation under severe operating conditions, with special emphasis given to high unit availability and reliability. The turbine has an of efficiency 34 percent, needs minimal maintenance, can reach full power in 16 minutes, and has low emission (NOx emissions of <25ppm). The CT11N2 is suited to a variety of applications, ranging from simple-cycle peaker operation, through industrial co-generation applications, to combined cycle power generation. The turbine has and efficiency of 33 percent, can operate on a wide range of fuels, has low emissions (NOx emissions of <25ppm), and has 1.5 million hours of operation at 99 percent reliability.

Source: Navigant Consulting, Inc.

Hybrid Renewable Cycles – Overview

Hybrid renewable cycles offer more efficient, cleaner operation compared to conventional gas turbines and overcome the intermittency issues associated with purely renewable systems. Hybrid renewable cycle gas turbines are an emerging technology still in the commercial development stage; there have been some small-scale demonstrations, but larger scale demonstrations are still in the planning stage. These systems are expensive and require large amounts of money to develop and there are few funding opportunities or incentives within the United States for hybrid projects that use fossil fuel contributions above 30 percent. There isn't a large amount of researched in the United States focused on hybrid renewable systems, although research focused on concentrated solar power will promote these systems. Exploiting the full efficiency potential of these systems will require the integration with combined-cycle plants, which requires that they be scaled up to power levels of above 50 MW. Research on small-scale demonstration solar gas turbine systems is needed to further understand and optimize the integration of concentrated solar and turbine technology. Further, research aimed at increasing the solar share of these systems is needed.

Hybrid Renewable Cycles – Description

Hybrid renewable power systems combine renewable and conventional energy conversion devices, or renewable and conventional fuels for the same device, that, when integrated, overcome limitations inherent in either. Combining renewable generating technologies with conventional back-up generation technologies is not what is meant by hybrid renewable cycles. These combinations have completely separated system technology leading to economic drawbacks. Real hybrid plants integrate renewable and conventional technologies; that is, they share much of their system, hence leading to economic advantages (HC1).

Sub-technologies of hybrid renewable cycles are:

- **Solar Gas Turbine Cycles** – Solar gas turbine systems use concentrated solar power to heat the pressurized air in a gas turbine cycle (Brayton cycle) before it enters the combustion chamber. In this sense these systems operate on the same principles as a recuperated cycle except the sun, rather than waste heat, is preheating the compressed air and a solar receiver, rather than a recuperator, is the device in which the preheating takes place. The solar receivers are heated by a field of concentrating mirrors and can achieve outlet temperatures of 800-1000°C; the combustion chamber then closes the gap between the receiver outlet temperature and the turbine inlet temperature (950-1399°C) and provides constant turbine inlet conditions despite fluctuating solar input.

- **Integrated Solar Combined Cycle System (ISCCS)** – In the ISCCS thermal power from solar troughs is integrated into the bottom cycle of a combined-cycle power plant. Essentially, the ISCC system uses the CSP element as a solar boiler to supplement the waste heat from a gas turbine to augment power generation in the steam Rankine bottoming cycle. The main difference between this technology and solar gas turbines (besides the use of solar troughs instead of receivers) is the heat in this system is added to the bottoming steam cycle, instead of the topping gas turbine cycle; this favors the lower temperature trough design.(HC2)

Solar gas turbine cycles are an immature technology; however they may have the long-term potential to produce abundant, clean, cheap energy. The main benefit of this technology compared to conventional systems is reduced emissions as a result of reduced fuel use. Table 51 below lists the key characteristics of solar gas turbines.

Table 51. Solar Gas Turbine Cycles Technology Characterization

Sub-Technology Characterization – Solar Gas Turbine Cycles	
Description	**Size/Applications –** These systems have been successfully incorporated into a 250 kW gas turbine as part of a test project. Ultimately these systems become most economic when they are incorporated into larger units (>10-15 MW), especially if they are able to exploit the full potential high efficiencies of combined cycle plants (>50 MW). These systems are most applicable in areas with high annual direct solar irradiation.(HC1) **Fuel/Cycles –** This system uses a combination direct solar irradiation and gas turbine fuel (natural gas, liquid natural gas [LNG], etc.). Depending on how much direct normal irradiation (DNI) is available, the system will use more or less conventional fuel to power the cycle. These hybrid systems have been studied for use in combined-cycles, recuperated cycles, and recuperated intercooled reheat (ICR) cycles. However, theoretically they can be incorporated into the simple-cycle. **Efficiency –** Moderately sized (5-15 MW) solar gas turbines, located in Daggett, California, operating for a 24-hour period may exhibit incremental solar to electric efficiency ranges of 14.6-19.0 percent[1]. Compared to similar conventional gas turbine systems using the same amount of fuel, the hybrid systems produce 9.6-38.4 percent more electricity annually (HC1).
Cost	**Total Installed Cost** • The specific investment cost of a moderately sized (5-15 MW) "first-of-its-kind" plant is 2,200-3,150 $/kW.(HC1) Of this total investment cost, 26-40 percent is expected to be from solar equipment (HC1). • The specific investment cost of a moderately sized (5-15 MW) second generation plant is 1,800-2,400 $/kW.(1) Of this total investment cost, 34-47 percent is expected to be from solar equipment (HC1). **O&M Cost** • The fixed O&M cost of a moderately sized (5-15MW) "first-of-its-kind" plant is 1.7-3.1 million $/year. Of this annual cost, 54-59 percent is expected to be from personnel expenses (HC1). • The fixed O&M cost of a moderately sized (5-15MW) second generation plant is 0.9 – 2.5 million $/year. Of this annual cost, 34-51 percent is expected to be from personnel expenses (HC1). **Total Levelized Cost ($/kWh)** • For a "first-of-its-kind" plant : 0.08-0.13 $/kWh, which is 33-75 percent more expensive than the levelized electricity cost (LEC) for the reference plant (HC1). • For a second generation plant: 0.06-0.09 $/kWh, which is 20-31 percent more expensive than the LEC for the reference plant (HC1).
Emissions	**CO2 –** A of a moderately sized (5-15 MW) solar gas hybrid plant can result in 1,600-15,500 metric tons of avoided CO2 emissions annually at a cost of 140-460 $/metric ton (HC1). **Criteria Pollutants –** Because the overall power cycle efficiencies of these systems are relatively high, and less fuel needs to be burned to produce electricity, and the system uses natural gas the criteria pollutants should be low.

Table 51 (Continued)

Sub-Technology Characterization – Solar Gas Turbine Cycles	
Benefits	Benefits of solar gas turbine cycles compared to gas turbine only systems: **Reduced Emissions** – These systems use less fuel to produce the same amount of electricity as reference conventional systems. **Avoided peak-capacity costs** – Because peak demand usually occurs in mid-day and at the hottest temperatures, the DNI at peak times will tend to be high; the hybrid system can capitalize on this fact and provide peak power at reduced fuel costs. **Fuel diversity** – These systems are less susceptible to natural gas price hikes because they can adjust their operation to drastically reduce their gas fuel usage. Operating at a capacity factor of 40 percent, these systems can operate on 70 percent solar power in Daggett, California (HC1). Benefits of Solar Gas Turbine Cycles compared to solar-only systems include: **Higher system reliability and availability** –as a result of having fully dispatchable power (HC1). **Reduced economic risk** – as a result of having fully dispatchable power and low additional investment due to an adaptable solar share.(HC1) **Higher efficiency** – These systems may exhibit solar to net electric efficiencies of up to 19 percent, this value is among the highest conversion efficiencies for solar electric technologies (HC1). Benefits of Solar Gas Turbine Cycles compared to ISCCSs: **Lower Emissions –** Higher conversion efficiency combined with a larger solar share leads to lower emissions. **More Flexible Power –** Because these systems use higher temperatures they may exhibit faster start up times, and therefore may be able to be used even in peaking applications. • **Lower cost of energy –** These systems may ultimately exhibit lower installation and operating expenses, and perhaps smaller, more modular systems (HC2).
Potential	Until the technology is mature enough to be scaled to the >50MW level there may be a market for these systems to be incorporated into smaller scale units (<5-10 MW) in distributed markets using cogeneration. Furthermore, cost predictions indicate potential competitive applications in the green power market (HC1).

Source: Navigant Consulting, Inc.

ISCCS technology is more mature than solar gas turbines with greater short-term perspective. The main advantage of this system over solar gas turbine cycles is its technological maturity; demonstration projects are already planned. Table 52 below lists the key characteristics of integrated solar combined-cycle technology.

Table 52. Integrated Solar Combined-Cycle Technology Characterization

Sub-Technology Characterization – Integrated Solar Combined Cycle System	
Description	**Size/Applications –** ISCCSs are seen as a technology that can be adopted in the near term (HC:1,2). They have applications in mid- to baseload applications. Initial projects plan to use 25-40 MW of solar capacity in combined-cycle plants, which range from 140-290 MW of total capacity (HC2). **Fuel/Cycles –** This system uses a combination direct solar irradiation and fossil fuel, depending on what conventional fuel is used in the combined-cycle plant. Depending on how much direct normal irradiation (NDI) is available, the system will use more or less conventional fuel to power the cycle. **Efficiency –** Designs for near-term ISCCS plants indicate an annual solar to electric efficiency of 13.7 percent for a 130 MWe plant with 30 MWe of solar capacity (HC2). Compared to similar conventional gas turbine systems using the same amount of fuel, the hybrid systems may produce 4-10 percent more electricity annually (HC1).
Cost	**Total Installed Cost** • The “first-of-its-kind” cost is expected to be 3,100 $/kWh for a 130 kWe plant with 30 kWe equivalent solar capacity (HC2). • The medium term cost is expected to be 1,370 $/kWh for a 130 kWe plant with 30 kWe equivalent solar capacity (HC2). **O&M Cost** • The “first-of-its-kind” cost is expected to be 0.11 $/kWh for a 130 kWe plant with 30 kWe equivalent solar capacity (HC2). **Total Levelized Cost** • The “first-of-its-kind” LEC is expected to be 0.148 $/kWh for a 130 kWe plant with 30 kWe equivalent solar capacity (HC2). • For a 310MW ISCCS in California the LEC of electricity with storage is expected to be 0.114 $/kWh without thermal storage and 0.095 $/kWh with storage (HC1). • In the medium term the LEC is expected to be 0.076-0.089 $/kWh; in the long term the LEC is expected to be ~0.064 $/kWh (HC2).
Emissions	**CO2 –** CO2 emissions will be avoided as the solar share of energy produced increases. **Criteria Pollutants –** Because the overall power cycle efficiencies of these systems are relatively high, and less fuel needs to be burned to produce electricity, and the systems tend to use natural gas the criteria pollutants should be low.

Table 52. (Continued)

Sub-Technology Characterization – Integrated Solar Combined Cycle System	
Benefits	Benefits of ISCCS compared to gas turbine-only systems: • **Reduced Emissions** – These systems use less fuel to produce the same amount of electricity as reference conventional systems. • **Avoided peak-capacity costs** – Because peak demand usually occurs in mid-day and at the hottest temperatures, the DNI at peak times will tend to be high; the hybrid system can capitalize on this fact and provide peak power at reduced fuel costs. • **Fuel diversity** – These systems are less susceptible to natural gas price hikes because they can adjust their operation to reduce their gas fuel usage. Benefits of ISCCS compared to solar-only systems include: • **Higher system reliability and availability** –as a result of having fully dispatchable power (HC1). • **Reduced economic risk** – as a result of having fully dispatchable power and low additional investment due to an adaptable solar share (HC1). • **Higher efficiency –** as a result of reduced part load operation and fewer start-up and shutdown losses. • **More Favorable Market Application** - They would allow mid-load to base-load operation, as opposed to the peak-load use, which is the primary market for concentrated solar power plants. • **Lower cost of energy** - Although yet to be built, studies have shown that operating costs would be reduced, cutting the overall cost of solar thermal power by as much as 22 percent compared with a conventional CSP trough plants (25 percent fossil) of similar size (HC2). Benefits of ISCCS compared to other solar-hybrid systems: • **Near term application**– These systems are more mature than other solar hybrid systems. There are four planned demonstration projects of greater than 130 MW. Additionally, these systems leverage solar troughs that are the most mature CSP technology with over 350 MW of capacity installed in California since the 1980s (HC2).

Source: Navigant Consulting, Inc.

Hybrid Renewable Cycles – Adoption Barriers

The most significant barriers to widescale adoption of renewable hybrid cycles are high cost, lack of incentives, and lack of research. Other barriers to widescale adoption of hybrid renewable cycles are outlined in Table 53 below.

Table 53. Hybrid Renewable Cycles Adoption Barriers

Adoption Barriers– Hybrid Renewable Cycles	
Technology	**Performance** • The solar gas turbine system lacks long-term operational testing, and the demonstrated power levels (250 kW) are too small for power plants. The technology is currently not mature enough to define a demonstration plant (HC9). • The solar share of solar gas turbine cycles needs to increase (current designs are calculated to have 9-28 percent annual solar share for baseload applications). • The solar share of ISCCSs needs to increase (current designs are calculated to solar shares of have 4 percent without storage and 9 percent with storage) (HC1). • The conversion efficiency of ISCCSs is limited by its low temperature operation. **Other technology** • Exploiting the full efficiency potential of combined-cycle plants with solar gas turbine cycles requires high power levels greater than 50 MW. Efforts to scale the technology to this size have not been attempted. • Because this solar gas turbine cycles are a new technology, they have a technological risk associated with them. Therefore, financing for these projects will be more expensive to account for this risk (HC9).
Market	**High cost** • Solar gas turbine cycle power production costs are still higher than with conventional fossil fuel options. The cost of solar components (for example, heliostats, receiver modules) need to be reduced. An emphasis should be placed on reducing the costs of heliostats (largest single capital investment in a central receiver plant) (HC2). • ISCCS power production costs are still projected to be higher than conventional fossil fuel options in the near term. An emphasis should be placed on reducing the cost of parabolic troughs. **Equipment Supply** • During the last years, some of the industrial knowledge on power tower technology was lost (for example, heliostat component supplier left business). Therefore the industrial experience has to be gained again.(HC9) **Other Market** • Few funding possibilities or incentives exist for hybrid systems with fossil contributions above 30 percent.(HC1) • The incentive programs available in both Spain and Nevada apply only to plants that operate on 85-100 percent solar power (HC2). • More attention is being paid to entirely solar-based systems; this is taking focus away from hybrid systems (HC2).

Source: Navigant Consulting, Inc.

Hybrid Renewable Cycles – Existing Research

There is little R&D in the United States focused specifically on hybrid systems; much of the research and funding comes from the international community. Table 54 below lists current research on hybrid renewable cycle technology.

Table 54. Hybrid Renewable Cycle Research

Existing Research–Hybrid Renewable Cycles	
US DOE / National Labs	**US DOE NREL/Sandia National Lab** – These two labs cooperate through SunLab—a partnership developed by the U.S. Department of Energy to administer its concentrating solar power R&D and analysis activities. The goals of SunLab include increasing the use of CSP in the United States, making CSP competitive in the intermediate power market, and developing advanced technologies that will reduce systems and storage costs. US DOE plans to achieve these goals through cost-shared contracts with industry (minimum 25 percent cost share), advanced research at its national laboratories, and working with other government agencies to remove barriers to the deployment of the technology. The objectives of the industry contracts include the development of storage solutions, manufacturing approaches, advanced optical materials, and new system concepts for large-scale CSP plants. US DOE is providing as much as $35 million over several years under this effort, and although it will not directly address hybrid systems, the technical and market gains achieved for solar trough and solar tower technology will benefit solar hybrid systems. **US DOE Solar Energy Technology Program (SEPT)** – The Solar program is US DOE's broader solar resource development program. In addition to advancing CSP under SunLab, the program also concentrates on breaking down the regulatory, technical, and economic barriers to integrate solar electricity into the electric grid, and identifying/breaking down market barriers beyond cost. While these activities don't directly affect hybrid solar systems they do provide some benefit.
International	**Plataforma Solar de Almería** – The REFOS receiver was tested. In 2002 three modules were coupled in series and achieved a series temperature of up to 800°C (Sugarmen et al., 2003). Tests at the PSA were continued until the summer of 2004 within the HST project funded by the German Ministry of Environment (BMU). As part of this project, one receiver was tested with outlet temperatures of up to 1030°C. **European Commission** – In its SOLGATE Project three solar receivers were connected in series and integrated into a 250 kW gas turbine engine. Two REFOS receiver modules were used in this project. **Global Environment Facility (GEF)** – The GEF has provided important grants ranging from $43-50 million for the development of 3 large (150-270 MW) ISCCS plants in Mexico, Egypt, and Morocco.
Private Sector	Since heliostats represent the largest single capital investment in a central receiver plant, efforts continue to improve their design with better optical properties, lighter structure and better control. Activities include the 150 m^2 heliostat developed by **Advanced Thermal Systems (USA)**, the 170 m^2 heliostat developed by **Science Applications International Corporation (USA)**, and the 150 m^2 stretched-membrane ASM-150 heliostat from **Steinmüller (Germany)**.

Source: Navigant Consulting, Inc.

Integrated Gasification Simple Cycle – Overview

This cycle may be a promising way to reduce the emissions and improve the efficiency of IC engines so they can meet ARB emission standards for DG applications. The extra components and complexity associated with this cycle can result in potentially expensive generation technologies. Older studies have shown that the efficiency gains from using this cycle in gas turbines may not be sufficient to compete with combined-cycle plants. A lack of industry champions willing to develop this cycle for gas turbines is a major market hurdle to adoption. A more current comprehensive paper study on the potential efficiency gains that result from using this cycle with the latest turbine technology could justify further research efforts. Similarly an engineering analysis of current cost and benefits of using this cycle with a gas turbine could spur further research efforts as well. Significant demonstrations and verification of system components are required to commercialize this cycle. Research on combustion of hydrogen-rich fuel in advanced gas turbine and IC engines is necessary to develop this cycle.

Integrated Gasification Simple-Cycle – Description

The integrated gasification simple-cycle uses exhaust heat to chemically reform fuel feedstock (typically natural gas) into a higher calorific flow fuel stream containing a significant concentration of hydrogen. This technique of recycling the engine exhaust heat increases the specific power and can reduce fuel use by increasing the efficiency of the generation technology. In addition, the hydrogen enhanced combustion also allows stable operation at a higher air-fuel ratio (leaner combustion) or greater amounts of exhaust gas recuperation for very low NOx production (IGSS:1,2). Typically this cycle will use natural gas as a fuel feedstock. The process used to reform the natural gas is catalytic methane-stream reforming. This endothermic reaction is one of the most mature chemical engineering processes and has been used extensively to produce hydrogen necessary for ammonia or methanol production. This reaction takes place in a heat recovery steam reformer and results in efficient heat recovery and clean fuel production (IGSS2).

The recovery of thermal energy is accomplished more efficiently by chemical means compared to recovering the heat by producing steam. (IGSS:2,3) Therefore, this cycle can be expected to produce significant gains in natural gas-to-electricity efficiency. Furthermore, specific power output is increased with this cycle due to increased turbine mass flow.(IGSS:2,4) The use of this cycle in a IC engine is expected to result in an efficiency increase of 5 percentage points (system efficiency of 42 percent).(IGSS:1) Early studies predicted that gas turbines using this cycle will exhibit efficiencies of 55-60 percent (HHV).

This cycle can be used in applications that require high efficiency and low NOx production. It has been primarily explored for use in gas turbines for base-load power applications. PIER has recently explored this cycle for use with reciprocating internal combustion engines to improve efficiency and reduce NOx emissions to levels that will allow this technology to meet ARB limits for distributed generation (IGSS1). Table 55 below lists the key characteristics of integrated gasification simple-cycle technology.

Table 55. Integrated Gasification Simple Cycle Technology Characterization

Technology Characterization – Integrated Gasification Simple Cycle	
Emissions	This cycle has the potential for low emissions due to its use of natural gas and its high efficiency. Additionally it has the potential for low NOx production due to the lower temperature burning hydrogen-rich fuel used[19] and the presence of steam in the reformate gas (IGSS:2,3). **CO2 –** CO2 emissions will be low if natural gas is used and efficiency is high. **Criteria Pollutants** • Sulfur compounds must be removed prior to entering the reformer so this cycle exhibits no SOx emissions. As discussed above NOx emissions are expected to be low as well. The high-efficiency burning hydrogen fuel will result in low CO emissions. Particulate emissions are expected to be insignificant (IGSS2).
Benefits	**Fuel Savings** – The high efficiency of this cycle can result in significant fuel savings, especially if these turbines displace older, less efficient prime movers (IGSS2). **Low Emissions** – NOx and other criteria emissions are expected to be low and high efficiencies can result in low CO2 emissions. **Ease of siting** – The siting flexibility is due to the ultra-low emissions, compact equipment configuration, lack of cooling requirement, and incorporation of a high level of silencing.(IGSS2) **High Availability** – With the exception of catalyst changeover (8 hours) the availability factor of the heat recovery steam reformer is expected to be the same as that of a heat recovery steam generator. This means that the overall availability of these cycles can be very competitive with conventional technology.(IGSS2) **Mature Technology** – Steam reformation of natural gas is an extremely mature technology.

Source: Navigant Consulting, Inc.

[19] Hydrogen is burns very efficiently allowing the fuel mixture to be diluted significantly to reduce to the adiabatic flame temperature below the temperature at which Zeldovich NOx forms.

Integrated Gasification Simple Cycle – Adoption Barriers

The most significant barriers for this cycle are its complex design and lack of an industry champion willing to develop it. Other barriers to widescale adoption of integrated gasification simple-cycles are outlined in Table 56 below.

Table 56. Integrated Gasification Simple-Cycle Adoption Barriers

Adoption Barriers– Integrated Gasification Simple Cycle	
Technology	**Performance** • Studies have shown that gas turbine integrated gasification simple cycle plants result in efficiencies only slightly higher than combined-cycle plants but require major modifications to the combustion turbine equipment and adds major additional equipment and complexity to the power plant.(IGSS4) **Reliability** • Efficient cleaning of the recycle flue gas may be required to eliminate the accumulation of fuel contaminant and equipment corrosion/wear products to protect the compressor and turbine.(IGSS4) **Other technology** • The sensitivity of nickel-based catalysts (in the HRSR) to sulfur species requires that the fuel be desulfurized to very low sulfur levels, using commercial zinc-based sorbent or activated carbon contacting methods.(IGSS4) • Significant demonstration and verification of system components are required to commercialize this cycle. • As a fuel, hydrogen behaves differently than a hydrocarbon in many ways, as a result the presence of hydrogen creates issues for combustion that require a different perspective than would a hydrocarbon fuel. Further, mixtures of gases often exhibit non-linear behavior and little data are available on the types of mixtures found in syngas. Two major areas that require continued research regarding hydrogen and syngas combustion are stability and reaction location.(IGSS5)
Market	**High cost** • Because of the extra components and complexity associated with this cycle, gas turbines using this cycle will require significant development effort and may be potentially expensive.(IGSS4) **Other Market** • Major turbine manufacturers may be reluctant to invest significant R&D into developing these cycles because they are expensive to develop and may compete with the combined-cycle systems they already offer

Source: Navigant Consulting, Inc.

Integrated Gasification Simple Cycle – Existing Research

Aside from research being funded by PIER, there has been little research recently on the integrated gasification simple-cycle. Table 57 below lists current research on integrated gasification simple-cycle technology.

Table 57. Integrated Gasification Simple-Cycle Research

Existing Research–Integrated Gasification Simple Cycle	
US DOE / National Labs	NETL – While they aren't investigating integrated gasification simple-cycles directly, they are engaging in research that can indirectly benefit these cycles. For example, research is being conducted to optimize the operation of current engines and turbines to use hydrogen and hydrogen-natural gas mixtures and to minimize emissions of NOx using this type of fuel.
California / PIER	PIER – PIER is funding the development of a integrated gasification simple-cycle for use in a 331 kWe reciprocating engine. The use of this cycle will allow the engine to meet CARB standards for DG applications and improve the efficiency of the engine by at least 5 percent. Almost two decades ago PIER investigated the use of the integrated gasification simple-cycle in gas turbine cycles for baseload stationary power applications.
Universities	There has been limited university research into integrated gasification simple cycles, especially in recent years.

Source: Navigant Consulting, Inc.

3.1.4. Replacement for Once-Through Cooling

The key takeaways from profiles on replacements for once-through cooling are:

- Equipping power plants that currently use once-through cooling with any of the alternative technologies may be expensive and may impact the plant efficiency.
- Older, Rankine cycle power plants will likely shut down as a result of the policy to eliminate once-through cooling.
- The cost of power plant cooling systems is highly dependent on the site.
- Typically, dry cooling is the most expensive alternative, followed by hybrid cooling, then closed-cycle wet cycle cooling towers.
- Even though wet cooling towers can use sea water, they still represent a significant improvement over OTC since they use only a small percentage of the amount of water used in OTC.
- Space (for example, for cooling tower) could be a limiting factor in retrofitting some plants with an alternative cooling system.

Alternatives to Once-Through Cooling

Once-through cooling (OTC) with seawater is an effective and relatively inexpensive cooling method for coastal power plants. However, California coastal power plants that rely on surface seawater intakes from oceans, bays, estuaries, and coastal wetlands for once-through cooling impinge 1,400 fish and other organisms per billion gallons of cooling water intake and entrain 13 million fish and other organisms per billion gallons of cooling water intake (overall cumulative entrainment mortality rate is probably between 1-2%); the ecological impact of OTC is large in California as coastal power plants are authorized to withdraw and discharge 17 billion gallons of ocean water daily.(OC:1,2) This cooling water also negatively impacts bay and estuarine environments by raising the temperature of the water. Alternative cooling technologies that avoid these negative environmental impacts include closed-cycle wet cooling towers, dry cooling towers, hybrid cooling towers, and the use of alternative cooling water sources such as recycled and treated waste water. Other entrainment and impingement reduction methods such as changes in intake location or physical or behavioral barriers have not proved to be a feasible and/or effective long-term solution for most California power plants (OC3).

Additionally, the potential California State Water Resources Control Board (SWRCB) policy on once-through cooling plants is anticipated to require the retrofit of all OTC plants, including the two nuclear plants, to recirculating cooling on a staggered schedule. Thus, plant operators will not invest in the use of screens, etc. until the policy is adopted or dropped or until they are required to use screens. Screens and other barriers may be a possible interim measure until plants must retrofit or retire.

The adverse environmental impacts of OTC can be avoided by using alternative cooling technologies such as dry cooling, wet cooling towers, hybrid cooling towers, and alternative cooling water. Sub-technologies for once-through cooling alternatives are:

- **Closed-Cycle Wet Cooling Towers –** This cooling process recycles the ocean cooling water as it passes the condenser several times with the heat dissipated to the atmosphere in cooling towers. This leads to a large reduction in cooling water demand that results in a similar reduction in entrainment and impingement impacts as well as thermal discharge levels (OC3).
- **Dry Cooling –** Air-cooled condensers (ACC) or direct dry cooling can eliminate the use of seawater entirely. Instead of transferring the heat to cooling water as in once-through cooling, an ACC radiates the heat from the stream in the condenser directly to the atmosphere. An ACC consists of flanged tube bundles arranged in an "A" frame configuration. To ensure adequate air movement through the ACC, numerous large fans are used (OC3).
- **Alternative Cooling Water Sources –** This alternative uses treated wastewater rather than ocean water for cooling. The substantially reduced flow levels of a wet cooling tower system make alternative sources of cooling water, such as treated wastewater effluent, feasible. If an appropriately sized treatment plant is available, treated wastewater can be used in a OTC configuration as well. Other, less prevalent sources of alternative cooling water include contaminated or brackish ground water, which may require varying levels of treatment before it can be used (depending on the contaminant level and local policy). Treated wastewater effluent to be used for cooling towers must be treated to meet tertiary treatment standards accordance with California Title 22.
- **Hybrid cooling towers –** Water-conserving hybrid cooling towers use both ACCs and wet cooling towers to provide a combination of evaporative and dry cooling. There are different ways to design a hybrid system. The wet and dry systems can be operated either in parallel or in sequence. The amount of water to be saved depends on the design and how the system is operated but ranges from 30 to 80%.

While dry cooling systems are most effective at reducing OTC environmental impacts, this benefit comes at the price of high capital costs, high power costs, and reduced plant performance.

Table 58 below lists the key characteristics of dry cooling technology.

Table 58. Dry Cooling Technology Characterization

Sub-Technology Characterization – Dry Cooling	
Description	**Size –** There are several large power plants in California using this cooling technology that are greater than 500 MW as well as many elsewhere. **Fuel –** If the plant doesn't operate at full capacity, it may increase its fuel consumption to make up for the lost power production due to the reduced efficiency of dry cooling compared to OTC. **Efficiency[20]–** These systems negatively impact the heat rate of the plant compared to a plant cooled with OTC, leading to approximate efficiency penalties of 8 percent reduced efficiency for a steam turbines and 2-6.5 percent reduced efficiency for combined cycle. These efficiency penalties are dependent on ambient conditions.(OC:2,14) A larger ACC can reduce the heat penalty but increases capital and operating costs. **Applications –** Plants that use steam turbines to generate electricity can use this technology as cooling is required to condense the steam. These systems become favorable in areas with water restrictions.
Cost	**Total Installed Cost ($/MW)** • The costs for these systems are highly site and application specific, depending highly on the ambient temperature and plant design. The cost of these systems can be optimized to minimize the efficiency penalty. These systems are generally the most expensive of the sub-technologies profiled. **O&M Cost ($/kWh)** • These systems have high parasitic load requirements due to the dependence on fans to move air through the ACC. These systems also affect the heat rate, leading to efficiency losses and therefore higher fuel costs. • Other O&M costs of these systems are low owing to their dry operation. They have been described as trouble free and easy to operate and require only regularly scheduled cleaning and no additional staff to maintain (OC14).
Emissions	To make-up for the energy loss from utilizing dry cooling as opposed to OTC, additional fuel will be required to maintain existing capacity factors. This results in increased emissions compared to the same plant cooled with OTC. **CO2[21]** • 9.4 percent increase in emissions for a steam turbine plant, 2.1 percent increase for a combined-cycle plant.(OC2) **Criteria Pollutants[1]** • Approximately 9 percent increase in NOx, SOx, CO, and PM2.5 emissions for a steam turbine plant (OC2). • Approximately 2 percent increase in NOx, SOx, CO, and PM2.5 emissions for a combined-cycle plant (OC2).

[20] Approximations based on national averages for nuclear plants operating at 67 percent of maximum capacity as reported by the US EPA.

[21] Emission increase percentages based on a hypothetical 300 MW simple-cycle steam plant and a 540 MW combined-cycle plant, both cooled with OTC.

Table 58. (Continued)

Sub-Technology Characterization – Dry Cooling	
Benefits	**Reduced Water Use –** These systems use absolutely no water for steam condensation. The only water use these systems require is for boiler make-up, other cooling applications, and the so-called "hotel load." This use amounts to about 0.3 percent of the OTC cooling water requirements. **Reduced Environmental Impact –** This technology totally eliminates both impingement and entrainment marine life and thermal impacts of cooling since there is no water use.

Source: Navigant Consulting, Inc.

Wet cooling tower technology negatively impacts plant performance much less than dry cooling. Further, wet cooling tower technology is a proven technology and significantly reduces the environmental impacts of OTC by using less water. Table 59 below lists the key characteristics of wet cooling technology.

Table 59. Wet Cooling Tower Technology Characterization

Sub-Technology Characterization – Wet Cooling Tower	
Description	**Size –** These systems can be deployed in a large variety of plants ranging from small plants (<25 MW) to large baseload plants (>500 MW). **Fuel –** If the plant doesn't operate at full capacity it may increase its fuel consumption to make up for the lost power production due to the reduced efficiency of wet cooling towers compared to OTC. **Efficiency**[22] **–** Recirculating wet cooling reduces plant efficiency, compared to plants which are cooled with OTC, by approximately 1.7 percent for steam turbines and 0.4% for combined cycle(OC:2,14). These losses are dependent on ambient conditions. **Applications –** Plants that use steam turbines to generate electricity can use this technology as cooling is required to condense the steam.
Cost	**Total Installed Cost** • New system and retrofit cost are site and application specific. The cost of the system can be optimized to reduce auxiliary power requirements and temperature effects (OC14). • EPA estimates suggest the retrofit cost for OTC plants are approximately $229/gpm of circulating water flow and a Stone & Webster Engineering Company study report calculates that retrofit costs average $113/kW (OC11). These systems are typically the most cost-effective of the sub-technologies profiled. **O&M Cost**[23] • The parasitic losses of these systems can be as high as 1.4 percent of plant capacity.(OC3) These systems also affect the heat rate leading to efficiency losses and therefore higher fuel costs. • O&M costs for these systems are highly site specific and depend upon fan/pump power, water treatment, and tower fill/condensate cleaning (OC14). • Typical O&M cost, excluding reduced capacity and efficiency costs are 1.5 $/MWh (OC3).
Emissions	To make-up for the energy loss by using wet cooling as opposed to OTC, additional fuel will be required to maintain existing capacity factors. This results in increased emissions compared to the same plant cooled with OTC. **CO2**[1] • 1.7 percent increase in emissions for a steam turbine plant, 0.4 percent increase for a combined-cycle plant (OC2). **Criteria Pollutants**[24] • Approximately 1.7 percent increase in NOx, SOx, CO, and PM2.5 emissions for a simple-cycle plant (OC2). • Approximately 0.4 percent increase in NOx, SOx, CO, and PM2.5 emissions for a combined-cycle plant (OC2).

[22] Approximations based on national averages for nuclear plants operating at 67 percent of maximum capacity as reported by the US EPA.

[23] Based on a $2 million O&M cost of a 500 MW plant with a CUR of 30 percent (OC3).

[24] Emission increase percentages based on a hypothetical 300 MW simple-cycle steam plant and a 540 MW combined-cycle plant, both cooled with OTC.

Table 59. (Continued)

Sub-Technology Characterization – Wet Cooling Tower	
Benefits	**Reduced Water Use –** Conversion from OTC to wet cooling towers can reduce cooling water demand by up to 95 percent (OC3). **Proven Technology –** Most inland California power plants use wet cooling towers (OC3). **Reduced Environmental Impact –** This technology substantially eliminates impingement and entrainment marine life since water requirements are reduced by 95 percent, and substantially reduces thermal impacts of cooling since most of the water is evaporated in this process. **Energy Savings –** The capacity and efficiency penalties of these systems are much lower than dry cooling and less sensitive to ambient conditions.
Potential	Given the environmental restrictions being imposed on California power plants using OTC, and the cost and effectiveness of these systems in at typical California sites, the market for this technology is promising.

Source: Navigant Consulting, Inc.

The costs, feasibility and performance impacts of using of alternative cooling water are highly dependent on site conditions. The use of alternative cooling water is a proven technology and significantly lowers the environmental impacts of OTC. Table 60 below lists the key characteristics of alternative cooling water technology.

Table 60. Alternative Cooling Water Technology Characterization

Sub-Technology Characterization – Alternative Cooling Water	
Description	**Size** – The size of the plant that can utilize alternative cooling water is limited by the volume of cooling water needed and the availability of the necessary volume of alternate cooling water. **Efficiency** – If the alternate cooling water is warmer than the ocean cooling water it replaces it can result in efficiency penalties of around 1-2 percent. **Applications** – Plants that use OTC, wet cooling towers or hybrid cooling towers can use treated wastewater, or other alternate cooling water sources, rather than ocean water for cooling purposes. Because of their reduced water needs, it is easier to incorporate treated wastewater and other sources of alternate cooling water into a wet cooling tower system than a OTC system. Because the feasibility of this option is dependent on many site-specific variables, its application is extremely limited.
Cost	**Total Installed Cost ($/MW)** • Cost can vary significantly given the amount of water treatment required, the proximity of the treatment plant or source of alternate cooling water to the power plant, and the geography between the plant and source of cooling water. Additionally, the cost of reclaimed water varies greatly from jurisdiction to jurisdiction. Some cities/districts charge 90% of potable water costs for reclaimed water. • Treated alternate cooling water is less corrosive than ocean water, so cooling tower construction materials may be less costly than is the case with salt water. • In the situation where the sewage plant, or source of cooling water, is close and piping costs are reasonable, the capital cost may be lower than for an ocean water cooling tower. **O&M Cost ($/kWh)** • Additional O&M for a plant using treated wastewater was may be incurred if the plant becomes less efficient as a result of the waste water being slightly warmer than the ocean water. • If contaminated or brackish groundwater is used, O&M cost stemming from water treatment will vary depending on what type and the level of contamination the water exhibits.
Emissions	If using waste water decreases efficiency, then more fuel must be burned to generate the same amount of electricity, this will effectively increase emission rates by approximately the same percentage that efficiency is decreased.

Table 60. (Continued)

Sub-Technology Characterization – Alternative Cooling Water	
Benefits	**Proven Technology** – There is substantial experience using this concept, especially in using treated waste water as alternate cooling water (OC3). **Reduced Environmental Impact** – This technology totally eliminates impingement and entrainment marine life and can eliminate the thermal impacts of cooling if treated waste water is used since most of the time used cooling water is routed back to the treatment plant. Using treated waste water can also have the added benefit of eliminating sewage flow to the ocean. **Politically Favored** – If alternate cooling water can be cost-effectively used, it is a politically favored option since it can completely eliminate or substantially reduce the use of ocean water. Additionally, if the used alternate cooling water is routed back to the treatment plant permits to discharge cooling water into the ocean can be avoided. **Reduced Capital Costs** – Depending on site conditions, the use of alternative cooling water can be more cost effective than using ocean cooling water (OC3). **Energy Savings** – The efficiency penalties of these systems are much lower than dry cooling and less sensitive to ambient conditions.
Potential	The market potential for this technology is primarily limited by the number of wastewater treatment plants, or sources of alternative cooling water, which are ideally located near power plants.

Source: Navigant Consulting, Inc.

Hybrid cooling systems are suited for applications where there is water scarcity and where freezing temperatures occur.

Table 61. Hybrid Cooling Tower Technology Characterization

Sub-Technology Characterization – Hybrid Cooling Tower	
Description	**Size** – These systems can be deployed in a variety of plants ranging from small plants (<25MW) to large base-load plants (>500MW). **Fuel** – If the plant doesn't operate at full capacity it may increase its fuel consumption to make up for the lost power production due to the reduced efficiency of hybrid cooling compared to OTC. **Efficiency** – These systems will reduce plant efficiencies compared to plants that use OTC, the exact percentage reduction of efficiency depends on the site conditions and how the system is operated and optimized. If the dry cooling portion of the system is used more the efficiency losses will be larger. In general the losses should be less than those of a purely dry cooling system however (OC12). **Applications** – These systems are used in areas that exhibit water scarcity (OC:7,8). They are an attractive choice in freezing climates as well since the dry cooling portion can be relied on more heavily.(OC14) Ideal for chemical and power plants where large water flows are required for cooling. There are few hybrid cooling towers installed in the United States however.
Cost	Installed costs and operating cost are dependent on how the system is optimized and designed(for example, how much water savings are desired) and ambient conditions. **Total Installed Cost ($/MW)** • Costs depend on the design but since the dry portion of a hybrid system is smaller than in a 100% dry system, they usually will cost less than these systems. The more the hybrid cooling tower relies on the dry system (for example, systems which are designed to save less water) the more expensive the systems can become. Systems designed to save low amounts of water may potentially cost more than purely dry systems. • Total system cost including power costs vary greatly depending on how the system is operated and designed and ambient conditions. Power costs are typically lower than those of a purely dry system.(OC14) **O&M Cost ($/kWh)** • O&M costs besides efficiency penalties and power costs are similar to the O&M costs of dry cooling systems.(OC14)
Emissions	Hybrid cooling decreases plant efficiency compared to OTC, therefore more fuel must be burned to generate the same amount of electricity; this effectively increases emission rates by approximately the same percentage that efficiency is decreased by.
Benefits	**Reduced Water Use** – Because some of the cooling load is handled by dry cooling, these systems reduce the water use compared to both OTC and wet cooling towers. Systems can be designed to handle 30% of the cooling load with dry cooling at peak operating conditions, reducing water use by the same amount compared to closed-cycle wet cooling. There are examples of installations on large power plants which reduce water consumption by 70% compared to wet cooling towers (OC9). **Energy Savings** – Automated control systems ensure optimal cooling performance while minimizing power consumption of dry cooling fans. This results in energy savings compared to purely dry cooling. **Improved Reliability** – Systems can be designed to operate 100% on dry cooling or 100% on wet cooling leading to high availability and reliability. Additionally, these systems can use lower quality water than wet systems without increased corrosion.(OC14) **Developed Technology** – This technology was developed in the early 1970s (OC9). **Operational Flexibility** – These systems can be designed and operated to achieve varying levels of water saving and plant performance optimization. They also exhibit improved characteristic in freezing conditions than pure wet cooling technologies.

Source: Navigant Consulting, Inc.

Alternatives to Once-Through Cooling – Adoption Barriers

The most significant barriers to widescale adoption of alternative to OTC are higher capital costs and reduced plant performance. Other barriers to widescale adoption of alternatives to once-through cooling are outlined in Table 62 below.

Table 62. Alternatives to Once-Through Cooling Adoption Barriers

Adoption Barriers– Alternatives to Once-Through Cooling	
Technology	**Performance** • Dry cooling tends to result in the most reduced plant production capacity (up to 25-95 MW on a hot day for a 500 MW plant [OC:3,14]), the highest increased parasitic load, and the most reduced plant efficiency. The exact amount of lost production capacity, parasitic load, and reduced efficiency depend on plant design and local conditions. • Other barriers of dry cooling compared to OTC cooling are increased noise (if low noise fans are not used) and visual impacts (OC3). • Compared to a plant with OTC, wet cooling towers result in slightly increased parasitic losses, and slightly reduced plant efficiency. • Other barriers of wet cooling towers compared to OTC cooling are increased noise and visibility of the cooling tower and plume. • Hybrid cooling results in efficiency and capacity penalties which are less than dry cooling but more than wet cooling. These penalties are highly dependent on mode of operation and ambient conditions (OC14). • Using treated waste water can decrease plant efficiency if the waste water is hotter than the ocean water it replaces. • Dry cooling and hybrid cooling operation and performance is highly dependent on plant design and ambient conditions. **Other technology** • The availability of sufficient space can be the most limiting factor in a wet cooling tower retrofit analysis (OC:2,4). • Alternative cooling water for wet cooling towers require increased condenser pressure compared to ocean water wet cooling towers. • Retrofitting these technologies for existing plants can be technically challenging requiring potentially significant installation and plant offline times. • Hybrid systems can be the most complex to control, if cooling water and air flow rates must be adjusted in accordance with cooling needs and ambient conditions. **Reliability** • Plant operators are hesitant to adopt hybrid cooling systems because there are too few examples of plants that have successfully adopted this technology.
Regulatory	**Permitting** • Wet cooling towers and the use of recycled waste water that involve intake of ocean water and/or discharge of water into the ocean and require a National Pollutant Discharge Elimination System (NPDES) permit. **Other regulatory** • Treated wastewater must be treated in accordance with California Title 22 before it is used in cooling applications. • The implementation of these technologies can be hindered by regulation related to land use planning, noise, visual impacts, water quality, cultural resources, and aesthetics.(OC2)

Table 62. (Continued)

Adoption Barriers– Alternatives to Once-Through Cooling	
Market	**High cost** • Dry cooling exhibits the highest installation and operating costs. • Wet cooling towers exhibit higher installation costs and operating cost compared to OTC, and depending on conditions the additional use of alternative cooling water can further increase these costs. • Hybrid cooling exhibits installation costs and operating cost, which are less than dry cooling but more than wet cooling. • The cost of using alternative cooling water is highly site-specific and can be prohibitive if the distance between the source of cooling water and the plant is large or the treatment requirements are high. **Other Market** • The practicality of alternative cooling water depends on the distance to a source of alternate cooling water of adequate size for the application, the geography between the source and the plant, and, in the case of using treated wastewater, the willingness of a treatment plant to sell its wastewater to the power plant.(OC3)

Source: Navigant Consulting, Inc.

Alternatives to Once-Through Cooling – Existing Research

The US DOE and NETL are responsible for much of the research and demonstrations in recent years concerning enhancements to OTC alternative technologies. Table 63 below lists current research on alternatives to once-through cooling.

Table 63. Alternatives to Once-Through Cooling Research

Existing Research–Alternative to Once-Through Cooling	
US DOE / National Labs	**US EPA –** Researched the efficiency and emissions penalties of OTC and developed analysis that can be used to assess the value of environmental impacts from OTC. **US DOE/NETL** – In 2003 the Innovations for Existing Plants program was broadened in 2003 to include research directed at coal-fired power plant related water management issues resulting in the Water Management Program. The program is built around four specific areas of research: 1) Non-Traditional Sources of Process and Cooling Water, 2) Innovative Water Reuse and Recovery, 3) Advanced Cooling Technology, 4)Advanced Water Treatment and Detection Technology. The short-term goal is to have technologies ready for commercial demonstration by 2015 that, when used alone or in combination, can reduce freshwater withdrawal and consumption by 50 percent or greater for thermoelectric power plants equipped with wet recirculating cooling technology, while achieving a levelized cost savings of at least 25 percent compared to state-of-the-art dry cooling technology. The long-term goal is to have technologies ready for commercial demonstration by 2020 that, when used in combination, can reduce freshwater withdrawal and consumption by 70 percent or greater, while achieving a levelized cost savings of at least 50 percent compared to state-of-the-art dry cooling technology. They are sponsoring three projects on advanced technologies which reduce cooling water requirements, and they are sponsoring 10 projects that investigate alternative cooling water sources. In total they are sponsoring 19 projects related to water-use at power plants.(OC17)
California / PIER	**The California Ocean Protection Council –** The OPC sponsored a study conducted by Tetra Tech that evaluates the logistical, regulatory, and economic factors that arise when a facility modifies its cooling water system by implementing technology-based measures designed to achieve the OPC performance benchmark. **PIER –** PIER has sponsored feasibility studies regarding alternatives to OTC for California coastal power plants. Additionally, PIER has funded research on alternatives to OTC technology such as spray-enhancement of air-cooled condensers (ACC), which will improve performance of these systems in hot weather, and the effects of wind conditions on ACCs. They have also conducted a study that investigates the cost and barriers associated with using spray-enhanced ACCs. They have conducted computational fluid dynamic studies to understand the effects of wind conditions on ACCs as well as field studies which collected valuable data and identified key effects of wind conditions on performance. A computation fluid dynamic model is also being created to investigate how to break up crosswinds, which negatively impact performance.
Universities	• **Improved heat exchanger geometries** – Research papers and reports published in 1995, 1998, and 1999 explained enhanced heat exchanger geometries which result in more efficient operation (OC14). • **Improved ACC performance with use of limited water** – Analyses performed about 18 years ago (Conradie and D. G. Kröger, 1991) illustrated that substantial performance enhancements could be achieved with a limited use of water in a dry cooling system. System analyses were been conducted in 2002 at the National Renewable Energy Laboratory (NREL) on four approaches to hot-day performance enhancement for a small dry-cooled geothermal plant. • **Optimization techniques** - There was some activity on computational procedures for system optimization and for determining wind effects on cooling systems (Conradie et al., 1998; Eldredge, 1995; Kintner-Meyer and A. F. Emery, 1994) in the mid to late '90s. • **Drexel University,** with funds from the US DOE, is conducting research with the overall objective of developing technologies to reduce freshwater consumption at coal-fired power plants. The goal of this research is to develop a scale-prevention technology based on a novel filtration method and an integrated system of physical water treatment in an effort to reduce the amount of water needed for cooling tower blowdown.

Table 63. (Continued)

Existing Research–Alternative to Once-Through Cooling	
Private Sector	• NETL is funding **SPX Cooling Technologies** in developing physical enhancements for air-cooled condensers (ACC) to improve fan airflow in windy conditions. By removing cross-wind effects on ACC fans, the SPX wind guides will increase ACC performance, thereby increasing the overall efficiency of the power plant. NETL is funding **Ceramic Composites, Inc.** and **SPX Cooling** to conduct research to develop high thermal conductivity foam to be used in an air-cooled steam condenser for power plants. The foam could significantly decrease energy consumption while enhancing water conservation within the power industry. Researchers are evaluating a variety of fin width to channel width ratios. Additionally, researchers are evaluating and testing Wavy, Chevron, Straight, and Harmon fin designs, comparing air velocity, the overall heat transfer coefficient, and performance ratios. Examples of possible benefits of the project include minimization of: water withdrawal and consumption; thermal impacts from warm water discharge; and impacts to aquatic life from water intake. Air2Air® condensing technology for wet cooling tower applications was previously investigated by **SPX Cooling Technologies** under a U.S. Department of Energy grant. SPX Cooling Systems lists a design annual average water recovery rate of 20 percent for its Air2Air™ condenser. In a current project SPX Cooling Technologies will further enable Air2Air® to become a commercially viable water saving technology by addressing cost issues as they relate to cooling tower superstructure volume, packing design, ducting details, heat transfer efficiency, and watertight wet path seals.

Source: Navigant Consulting, Inc.

3.1.5. Carbon Reduction

The key takeaways from profiles on pre-combustion capture systems are:

- Costs of pre-combustion capture systems vary widely between new plants and retrofits.
- Cost of retrofitting existing plants with pre-combustion carbon capture systems is typically prohibitive.
- Cost of these systems depends on the amount of carbon in the fuel source; however, the cost/ton of carbon is still lower with a dirtier fuel (for example, coal), while the cost per MWh is lower with a cleaner fuel (for example, natural gas).
- Lack of utility-scale demonstrations has limited the adoption of this technology; the Recovery Act has allocated funding for utility-scale demonstrations.
- US DOE expects that new research on this technology could lead to significant cost reductions.
- IGCC plants with pre-combustion capture have the lowest energy requirements for capture, 0.194 kWh/kg of CO2 processed, compared to 0.317 kWh/kg of CO2 processed for NGCC plants with post-combustion capture (PR21).
- IGCC with pre-combustion capture shows the most long-term promise for CCS (PR20).
- The success of pre-combustion carbon capture technologies will depend on the success of carbon sequestration technologies.

Pre-combustion capture is more suited for IGCC plants, and post-combustion capture is more suited for retrofits and NGCC plants. Table 64 below compares pre- and post-combustion capture.

Table 64. Comparison of Pre- and Post-Combustion Capture

Technology Comparison – Pre-combustion capture vs. Post-combustion capture		
Pre-combustion Capture	**Explanation of Energy Penalty**	Electric efficiency is reduced relative to the amount of CO_2 captured. The efficiency of a dry fed IGCC plant with pre-combustion capture can be reduced from 47 percent to 32-40 percent (depending on if a clean vs sour shift reaction is used).(PR3,PO3) This loss is the result of reduced lower heating value (LHV) of the synthesis gas, as well as the energy consumption for CO2 separation and compression. However future (when the technology is mature) IGCC plants with pre-combustion capture are estimated to have efficiencies of 43-47 percent (PR: 4, 20). The energy requirement for stripping the CO2 from the absorbing solvent is about 20 percent lower than for post-combustion capture because much of the CO2 flashes out of the physical solvent once the pressure is reduced for stripping and because of the relatively favorable CO2 concentrations in the process (which range from 15 to 80 percent) (PO1).
	Energy Efficiency Penalty	• IGCC plant = 15-31 percent (PR3, PO3), 0.194 kWh/kg of CO2 processed (PR: 4, 21). • Estimates for newer plants are typically in the 15 percent range. • Future New NGCC Plants (2020-30) = 8-12 percent.
	Likely Application	Near Term: New IGCC plants. Long Term: New IGCC plants, new NGCC plants.
Post-combustion Capture	**Explanation of Energy Penalty**	The process to regenerate the chemical adsorbent used in post-combustion capture involves steam stripping the rich solvent at a high energy penalty–about 1.5 tons of steam per ton of CO2 removed (PO:1,3).
	Energy Efficiency Penalty	• NGCC plant = 13-17 percent (PO:1-3), 0.317 kWh/kg of CO2 processed (PR21). • PC plant = 25-42 percent (PO:1-3). • Future New NGCC Plants (2020-30) = 6-10 percent.
	Likely Application	Near Term: Retrofit applications, new NGCC plants, new PC plants. Long Term: New NGCC plants, new PC plants.

Source: Navigant Consulting, Inc.

Pre-Combustion Capture

Pre-combustion CO2 capture is accomplished by one of two general processes. Both processes start off by gasifying the feedstock in a O2 blown gasifier system via a steam reforming reaction to create what is known as "syngas," or a mixture of primarily CO and H2O. The first process employs a catalytic sour water-gas-shift reaction in which the syngas is reacted with steam to create CO2 and H2. This is followed by desulfurization and CO2 recovery within the same acid gas removal unit. The second process desulfurizes the syngas first followed by a water-gas-shift reaction and then removal /recovery of the CO2. The choice of either scheme depends primarily the extent to which cooling of the raw syngas is accomplished in a syngas cooler before the syngas is quenched /scrubbed with water to remove particulate matter. The final product of both processes is a produce a "decarbonized" fuel gas for combustion in a gas turbine.

Fuels used in pre-combustion capture are natural gas, coal, other fossil fuels, and biomass. Theoretically any carbonaceous fuel can be gasified and decarbonized. (PR6) If the efficiency of contemporary gas turbine systems are analyzed with the addition of pre-combustion capture technology the capture technology results in an energy penalty. However future (when the technology is mature) IGCC plants with pre-combustion capture are estimated to have efficiencies of 43 percent (PR4).

Pre-combustion capture can be utilized at large fossil-fueled IGCC plants, such as power plants, oil refineries, and cement plants. The technology should be employed at large plants to maximize the amount of CO2 capture that can take place. Applications at plants that are situated near enhanced oil recovery sites may be an attractive initial market. In general the viability of any type of capture application depends on the availability and location of sequestration sites. Although pre-combustion capture uses well-established technologies, it is not appropriate or practical in most cases to retrofit it to existing generators (PR:2,4,6).

The cost of pre-combustion capture depends on whether the installation is new or retrofit, the type of fuel being used, and the type of plant. Pre-combustion capture is the most commercially developed process and may prove to be less expensive than post-combustion capture (PR6).

Table 65 below lists the key characteristics of pre-combustion capture.

Table 65. Pre-Combustion Capture Technology Characterization

Technology Characterization – Pre-combustion capture	
Cost	Fuel feedstocks with higher carbon content naturally give rise to larger volumes of CO_2 for a given output of hydrogen. This means that the cost of capture will be considerably higher for production of hydrogen from these sources. However, since the total volume of CO_2 is so much higher, the cost per unit of CO_2 abated is lower, making some of the cost data somewhat counterintuitive. In general capture cost will be lower for new construction versus retrofit (PR:4,6). Assumes 500 MW plant with 85 percent capacity factor and 90 percent CO_2 removal. Does not include cost to transport, inject, or store which are on average \$8/tonne CO_2. If the sequestration site involves EOR, up to \$20 per metric ton of CO_2 (the average rate paid in 2007 in the United States for CO_2 for EOR) could be subtracted to get the CCS cost (PR6). **Total Installed Cost (\$/MW):** Coal Plant (IGCC): 3170-3640 \$/kW, 30-33 percent more expensive than base plant without capture. **Cost of CO_2 Avoided:** Coal Plant (IGCC): 40-47 \$/tonne (PR6). **O&M Cost:** Coal Plant (IGCC): 1.05, the cost is 16 percent more than the reference plant (PR6). **Incentives:** • Power Sector Investment Tax Credits – IGCC 20 percent credit capped at \$800 Million. Other Advanced coal 15 percent credit capped at \$500 million (PR7). • Industrial Gasification Investment Tax Credit – 20 percent credit capped at \$350 Million. Maximum of \$650 million of credit-eligible investment allocable to a single project (PR7). **Total Levelized Cost :** Coal Plant (IGCC): 0.091- 0.096 \$/kWh, 27-30 percent more expensive than reference plant (PR6).
Emissions	**CO_2:** Depending on how much carbon capture is employed plants with this technology will emit little to no CO_2. **Criteria Pollutants:** Plants using this technology will be designed to emit small amounts of criteria emissions, however NO_x emissions require extra effort to mitigate. The combustion of high H_2 concentrated gas can lead to high NO_x emissions so extra mitigation strategies need to be employed such as diluting the H_2, using SCR, and/or using specially designed low NO_x combustors (PR:2,5).
Benefits	• **Reduced Emissions –** Plants that use pre-combustion capture will not only exhibit little to no CO_2 emissions, but they will exhibit little to no criteria pollutants as well. • **Proven Technology –** Pre-combustion capture is the most mature of the carbon capture methods and uses technologies that are already in wide application. Natural gas reforming is deployed on a huge scale in the chemical industry and oil refining industry. Gasification of coal relies on integrated gasification combined cycle (IGCC) power plants. These are not yet commercial, but the technology has been developed and demonstrated (PR:4,5). • **Lower Costs –** Compared to post-combustion capture the concentrations of CO_2 are higher, and thus the volume of gas being treated in pre-combustion capture is lower and requires less energy (about 20 percent less) to separate out, leading to lower capital and operating costs (PR:4,6,12). • **Higher Efficiency –** The higher CO_2 concentrations of pre-combustion capture also lead to higher efficiencies compared to post-combustion capture since the solvents used require less energy to restore (PR4). • **Compatible with Hydrogen Economy –** Plants employing pre-combustion capture will use the same type of technology necessary to produce hydrogen on a utility scale (PR4). • **Increased power output -** A nearly "flat rating" of the engine output with respect to the ambient temperature may be realized by opening up the guide vanes as the ambient temperature increases, the compressor inlet guide vanes being typically closed at the lower ambient temperatures to compensate for the larger mass flow rate of the syngas and the diluent.(PR2) • Penalty of using an SCR to reduce NO_x emissions in a decarbonized syngas fired combined cycle can be less severe as compared to its use in an IGCC without upstream CO_2 capture (PR2).

Source: Navigant Consulting, Inc.

Pre-Combustion Capture – Adoption Barriers

The most significant barriers to widescale adoption are CO_2 capture cost and efficiencies and lack of utility-scale demonstration projects. Other barriers to widescale adoption of alternatives to once-through cooling are outlined in Table 66 below.

Table 66. Pre-Combustion Capture Adoption Barriers

Adoption Barriers – Pre-Combustion Capture	
Technology	**Performance** • Electric efficiency is reduced relative to the amount of CO_2 captured. This loss is the result of reduced lower heating value (LHV) of the synthesis gas, as well as the energy consumption for CO_2 separation and compression. The efficiency of a dry fed IGCC plant can be reduced from 47 percent to 32-38 percent (clean vs sour shift reaction) (PR3). • Lower efficiencies will require greater fuel use per unit of electricity produced. If this energy is being provided from fossil fuels, this will create a corresponding increase in the impacts of this fossil fuel production and use, from landscape impacts of coal mining to spills from oil transportation (PR16). • Technology development in advanced separation membranes, oxygen generation, and gas turbines is needed to reduce cost and improve efficiency (PR6). • Due to the high H_2 content of the syngas stream, the use of current design pre-mixed gas turbine combustors to limit NO_x formation is precluded. Instead diluent addition (N_2 and/or H_2O) is required to reduce the NO_x generation when using diffusion type combustors. This addition can have negative effects on the firing temperature and on the thermal barrier coatings and any ceramics that may be used in advanced gas turbines in the future.(PR2) • The pressure ratio of the gas turbine increases when firing syngas. This combined with the effect of lowering the firing temperature can create suboptimal conditions for the steam cycle of a combined-cycle plant (PR2). • Development of low NO_x combustors for turbines using decarbonized fuel has a number of technical challenges to overcome due to the presence of a large concentration of H_2 in the syngas. **Reliability** • Although all of the main process steps used in pre-combustion capture are industry proven, they need to be scaled up and demonstrated at utility scales in a single integrated power plant application (PR:5,6).

Table 66. (Continued)

Adoption Barriers – Pre-Combustion Capture	
Regulatory	**Permitting** • In California applying the current regulatory framework to obtain permitting for a CCS project leads to complexities and ambiguities as CCS-specific regulatory and statutory frameworks do not yet exist. Within a CCS project, the sequestration site is the element least accommodated by current regulatory and statutory frameworks (PR6). • Authority(ies) to regulate in a uniform manner the siting, transport, injection, sequestration, and accounting of CO2 for all potential types of sources and sequestration sites and for CO2 sequestration need to be streamlined and clarified. **Other regulatory** • The fact that no policy yet exists to establish a price for CO2 in the marketplace makes assessing the economics of carbon capture challenging (PR6). • Regulation addressing issues such as ownership conflicts among mineral estate interests, pore space/storage owners, surface interests, and groundwater users; issues of public good; and use of eminent domain in condemnation of storage space and transportation corridors need to be streamlined and clarified (PR6). • Regulation addressing long-term liability issues, including qualifications, procedures, funding mechanisms, and potential to establish a mechanism or authority to transfer liability/ownership to the state or other public entity need to be streamlined and clarified (PR6).

Source: Navigant Consulting, Inc.

Pre-Combustion Capture – Existing Research

Opportunities for significant cost reductions exist since very little R&D has been devoted to CO2 capture and separation technologies. Table 67 below lists current research on pre-combustion capture.

Table 67. Pre-Combustion Capture Research

Existing Research–Pre-combustion Capture	
US DOE / National Labs	**FutureGen** - In February 2003, US DOE announced the FutureGen Initiative, "A Coal-fueled Prototype for a hydrogen/carbon sequestration power plant". A $1 billion coal-based IGCC program is proposed to provide 275 MW of power, 1 million tons/year of CO2 for sequestration in a geologic formation and hydrogen for fuel cells and later transportation. US DOE envisages the project as a "large scale engineering laboratory for testing new technologies".(PR7) On June 24, 2008, The U.S. Department of Energy (US DOE) issued a Funding Opportunity Announcement (FOA) to invest in multiple commercial-scale integrated gasification combined cycle (IGCC) or other clean coal power plants with cutting-edge carbon capture and storage (CCS) technology under the Department's restructured FutureGen program. The solicitation is seeking multiple cost-shared projects to advance coal-based power generation technologies which capture and store the greenhouse gas carbon dioxide (CO2). The Department anticipates $290 million will be available for funding of selected projects through fiscal year (FY) 2009 and an additional $1.01 billion is expected to be available in subsequent years, subject to appropriations by Congress.(PR13) • **NETL's Carbon Sequestration Program** – This program is dedicated to helping to develop technologies to capture, purify, and store carbon dioxide. NETL's pre-combustion CO_2 capture focus area calls for the following R&D goals: By 2014, initiate at least two slipstream tests of novel CO_2 capture technologies that offer significant cost reductions; By 2018, initiate large-scale field testing of promising novel CO_2 capture technologies. Near-term applications of CO_2 capture from pre-combustion systems will likely involve physical or chemical absorption processes, with the current state of the art being a glycol-based solvent called Selexol. Mid-term to long-term opportunities to reduce capture costs through improved performance could come from membranes and sorbents currently at the laboratory stage of development.(PR12) • **NETL's Gasification Research Program** - Research is being conducted to improve gasification technology such that its costs without capture will be comparable to electricity costs from pulverized coal without capture, potentially reducing further the cost of pre-combustion CO2 capture in the future.(PR14) • **The Regional Carbon Sequestration Partnerships (RCSP)** - This is a US DOE formed government/ industry effort tasked with determining the most suitable technologies, regulations, and infrastructure needs for carbon capture, storage, and sequestration in different areas of the country. The Regional Partnerships' initiative is being implemented in three phases: characterization phase, validation phase, and developmental phase. Large-scale field test have already been awarded and represent the major geologic basins throughout the United States and Canada. • **US EPA** – They have has examined the suitability of provisions for injection wells under its Underground Injection Control program.(PR6)
California / PIER	**PIER –** Much of the research conducted by PIER has focused on the sequestration side of CCS. Much of the research has focused on an assessment of the viability and availability of sequestration sites in California.

Table 67. (Continued)

Existing Research–Pre-combustion Capture	
Other States	**The Carbon Sequestration Leadership Forum (CSLF)** – This international climate change initiative is focused on developing improved, cost-effective technologies for the separation and capture of CO2 and for its transport and long-term safe storage. The purpose of the CSLF is to make these technologies available internationally and to identify and address wider issues relating to carbon capture and storage. The RCSP's projects have been recognized as CSLF projects (PR10). **Interstate Oil and Gas Compact Commission** – In September 2007, it published a legal and regulatory guide for U.S. states and Canadian provinces (PR6).
Universities	**Energy Research Center of the Netherlands** – Published a paper in 2007 that presented the design for a more efficient water gas shift reaction that can be integrated into a pre-combustion capture IGCC plant. **Scottish Center for Carbon Storage** - Total £4M with a further £900K from the Scottish Enterprise and Scottish Funding Council to develop advanced carbon capture technologies based on adsorption and membrane processes. Total 3.48M€ to develop ideal pore structures and chemical compositions, including synthesis routes, required for adsorbents to capture carbon dioxide from a mixed gas streams. Total 2.57M€ to the development of ultra-high performance, high temperature, gas separation materials based on newly emerging porous, inorganic materials (PR5).
Utility	**EPRI** – EPRI has conducted a significant amount of research into the cost, performance , operating experience, risk, market, potential, and retrofit opportunities of CO2 capture and storage. This is evident from the number and scope of the reports they have prepared on these topics.
Private Sector	**CO2 Capture Project/Cache**t – two joint industry projects that are focusing research on improving CO2 capture technologies for natural gas feeds for power production and existing large combustion sources, such as process heaters and boilers, or gas turbines (PR6). **CoalFleet program** – The power industry led CoalFleet program was initiated in 2004 and is being managed by EPRI. This program is aimed at encouraging the deployment of advanced clean coal technologies (IGCC, USC PC and SC CFBC), which are CO2 capture ready (PR7).

Source: Navigant Consulting, Inc.

3.2. Secondary Focus Technologies

3.2.1. Advanced Coal/Biomass Combustion

The key takeaways from profiles on advanced coal/biomass combustion are:

- There is limited electricity generated from coal in the California; however, 17 percent of power consumed in the state is imported from coal power plants outside the state.
- The Energy Commission has invested some resources, but relatively much smaller than US DOE investments, for the development and demonstration of advanced coal/biomass combustion technologies.
- Repowering old coal plants that export power to California with advanced coal combustion technologies could provide a significant carbon reduction opportunity

Integrated Gasification Combined Cycle

Integrated gasification combined cycle (IGCC) is a process that converts low value fuels such as coal, petroleum coke, orimulsion, biomass, and municipal wastes into a high value, low Btu natural gas-type fuel, also called “synthesis gas” or simply “syngas.” This gas is used to power a gas turbine whose waste heat is passed to a steam turbine system (Combined-cycle gas turbine). When used to fuel a combined gas turbine and steam turbine plant, known as a combined-cycle system, coal-based syngas fuel produces electricity more efficiently and with lower emissions than traditional direct fire coal boilers (IG9).

The physical IGCC plant is comparable in size to a conventional coal-fired power boiler plant, but unlike a conventional coal plant, an IGCC plant does not require additional area for scrubber sludge treatment or ash dewatering. (IG10) Typically, plants range in size from 500-600 MW (IG8).

IGCC plants use coal, petroleum coke, orimulsion, biomass, and municipal wastes as fuels (IG10). Efficiencies usually range from 38.5 - 40.0 percent HHV (IG8).

Integrated gasification combined cycle power plants have lower emissions than conventional coal plants. Table 68 below lists the key characteristics of IGCC.

Table 68. IGCC Technology Characterization

Technology Characterization – Integrated Gasification Combined Cycle	
Cost	For a 380 MW IGCC plant with carbon sequestration: **Total Installed Cost ($/kW)** • $3,496/kW (IG11). • IGCC capital cost should be within10 percent of Supercritical plants (IG8). • The IGCC target price is ~1606$/kW (IG8). **O&M Cost ($/kWh)** • $4.44/kWh (IG11). • $46.12/kW (IG11).
Emissions	**CO2** • 1700 lbs/MWh (IG8). • High IGCC efficiencies yield CO2 greenhouse gas emissions that are 12 percent lower than those of state-of-the-art coal steam-boiler plants. These emissions are approximately 30 percent lower than those of average coal plants operating today (IG9). **Criteria Pollutants** • IGCC SO_x, NO_x, and particle emissions are fractions of those of a conventional pulverized coal boiler power plant. As a consequence, meeting air emissions regulations and obtaining local and governmental environmental permits for an IGCC plant requires significantly less effort and time (IG10). • IGCC NOx emissions are approximately half those of modern pulverized coal steam-boiler plants. About 0.07 lb/million Btu NOx emissions can be achieved through IGCC (IG9).
Benefits	• Water consumption of an IGCC plant is approximately 30 percent lower than a conventional coal plant. Also, lime or limestone is not required for desulphurization (IG10). • IGCC plants are highly competitive commercially, producing electricity at costs below that of conventional solid fuel plants (IG10). • Emissions reductions (IG10).

Source: Navigant Consulting, Inc.

Ultra-Supercritical Pulverized Coal

An ultra-supercritical coal-fired plant (USPC) pulverizes coal to fuel burners, which turn water to steam that drives a turbine to create electricity. (US12) The steam power cycle for the proposed units is referred to as an "ultra-supercritical" cycle. This terminology is used to differentiate the pressure and temperature conditions of the steam as compared to other types of coal plants with lower pressure and temperature conditions. The ultra-supercritical cycle is currently the most advanced steam power cycle that engineers have been able to develop that is both economical and reliable. Environmentally, it is the cleanest commercially viable pulverized coal technology (US14).

USPC plants range in size from 500-600 MW (US3, 4, 13). These plants burn coal as fuel: butiminous, lignite, or PRB (US13). Most plants have an efficiency of 40 percent (US13), but the most advanced ultra-supercritical plant can achieve up to 50 percent efficiency (US14).

Ultra-supercritical pulverized coal plants are more efficient than conventional coal plants. Table 69 below lists the key characteristics of USPC plants.

Table 69. USPC Technology Characterization

Technology Characterization – Ultra-Supercritical Pulverized Coal	
Cost	**Total Installed Cost ($/kW)** • $1.3 billion for a 600 MW plant in Texas (US5). • The higher-cost advanced metals make an ultra-supercritical plant up to 5 percent more expensive to build than a same-sized supercritical plant (US12). • Total Plant Cost is ~$1500/kW (US8). **O&M Cost** • There are too few operating plants in the United States to get meaningful estimates of O&M cost (US22).
Emissions	**CO2** • By using less coal, the plant emits less carbon dioxide per kilowatt generated. (US12) • 1738 lb/MWh (US13). • increases in plant efficiency can reduce CO2 emissions by a ratio of 2 to 1 (US14) **Criteria Pollutants** • NOx – 0.45 lb/MWh (US13). • SO2 – 0.75 lb/MWh (US13). • PM – 0.09 lb/MWh (US13).
Benefits	The advantage of using ultra-supercritical technology over other types of pulverized coal technology is that it takes less energy to convert the water used in the power generating process to steam. This means that less fuel needs to be burned to generate the same amount of power. When compared to older technologies, the ultra-supercritical power plants operate at increased efficiency and, as such, have considerably lower fuel costs (US14).

Source: Navigant Consulting, Inc.

Supercritical Circulating Fluidized-Bed Combustion

Circulating fluidized bed (CFB) combustion, with its well-known benefits of fuel flexibility and low emissions, has established itself as a boiler technology suitable for utility-scale power generation. Because a supercritical CFB boiler will be designed with lower mass flow rates, it will operate with a "natural circulation" rather than a "once-through" characteristic (SF17).

The first supercritical CFB (SCFB) combustion plant is being built in Poland, with a targeted completion date in 2009 (SF6, 16). This plant will be 460 MW (SF6). ALSTOM Power also has supercritical designs prepared for CFB plants up to 600 MW (SF23).

SCFB plants use coal, coal slurry, and biomass as fuel (SF16). Efficiencies are expected to be 46 percent (SF15).

Supercritical circulating fluidized-bed combustion is still an emerging technology. Table 70 below lists the key characteristics of SCFB plants.

Table 70. SCFB Technology Characterization

Technology Characterization – Supercritical Circulating Fluidized-Bed Combustion	
Cost	**Total Installed Cost** • €150 million for a 460 MW plant (SF6)
Emissions	**CO2** • 15 percent to 20 percent reduction compared to conventional methods (SF16)
Benefits	• Improved fuel flexibility (SF16) • Operational flexibility with load swing potential (SF16) • Modular design (SF16)

Source: Navigant Consulting, Inc.

3.2.2. Carbon Capture and Sequestration

The key takeaways from profiles on carbon capture and sequestration are:

- The opportunity for carbon capture and sequestration in California is mostly tied to natural gas power plants linked to enhanced oil recovery.
- Post-combustion capture is better suited for retrofitting of existing power plants.
- Post-combustion capture technology is more cost-effective for coal plants than for natural gas plants.
- Post-combustion capture is more energy-intensive than pre-combustion capture.
- Post-combustion capture technology requires additional development and cost improvement.
- Compared to other carbon reduction approaches, carbon capture is more expensive.
- The success of oil recovery carbon sequestration depends on the alignment of interest between the oil producer and society's need to reduce carbon emissions

Post-Combustion Capture

Post-combustion capture consists of processes that separate CO2 from flue gas after conventional combustion. CO2 capture from this resulting flue gas is relatively capital- and energy-intensive due to the low pressure and low CO2 concentration in a flue gas composed mostly of nitrogen. Post-combustion separation requires chemical solvent absorber/stripper systems, typically using amine solvents and special chemical inhibitors to curb reactions with the residual O2. To regenerate the amine solvent by reversing the reaction requires heat, typically from steam, and the energy requirements are quite high—about 1.5 tons of steam per ton of CO2 captured. In addition, the flue gas must be low in nitrogen dioxide (NO2) and especially sulfur dioxide (SO2) before entering the CO2 absorber to avoid fixation reactions with the recycled amine solution. A major challenge for post-combustion CO2 capture is accommodating the large requirements for heat and power for amine stripping and for compression and drying of the wet (water-saturated) CO2 that leaves the stripper. These requirements can significantly reduce the overall (net) capacity and efficiency of the plant (PO1).

Only about 10 small operating post-combustion CO2 capture facilities exist worldwide for flue gas application. The largest operating system captures only about 330 tons of CO2 per day. However, post-combustion capture is being proposed for a large Norwegian 800 MW natural gas-fired combined-cycle power plant (PO1). Fuels for post-combustion capture technologies include natural gas, coal, other fossil fuels, and biomass. Theoretically any carbonaceous fuel can be gasified and decarbonized (PO6).

Post-combustion capture of CO2 has an associated efficiency penalty due to the large amounts of energy required to steam strip and regenerate the amine solvents.(PO3) These efficiency penalties for supercritical pulverized coal plants with post-combustion capture are 25-42 percent(PO:1-3). For NGCC plants these penalties are 13-17 percent (PO:1-3). These systems have been studied for use in sub-critical and super-critical pulverized coal plants as well as natural gas combined-cycle plants. This process can be added to any existing flue gas stream, which makes this technology well-suited for retrofitting existing facilities without major process changes and rebuilds; it is, in fact the lowest cost retrofit option (PO:1,4).

Post-combustion capture is the best suited capture technology for retrofit applications; however it is also very energy-intensive. New post-combustion capture plants produce electricity at significantly higher COE; electricity from retrofit plants would cost even more. Table 71 below lists the key characteristics of post-combustion capture.

Table 71. Post-Combustion Capture Technology Characterization

Technology Characterization – Post-Combustion Capture	
Benefits	**Reduced Emissions -** Plants that use post-combustion capture will not only exhibit little to no CO2 emissions, but they will exhibit little to no criteria pollutants as well. **Readily Adoptable -** The key advantage of post-combustion CO2 capture is its ability to be added onto any existing flue gas stream. In addition, the electric utility industry generally views this as similar to flue gas desulfurization systems, with which coal-fired utilities have significant experience (PO1).
Cost	Assumes 500 MW plant with 85 percent capacity factor and 90 percent CO2 removal. Does not include cost to transport, inject or store which are on average $8/tonne CO2. If the sequestration site involves EOR, up to $20 per metric ton of CO2 (the average rate paid in 2007 in the United States for CO2 for EOR) could be subtracted to get the CCS cost (PO1). **Total Installed Cost (PO:1,2)** • Supercritical PC: 3360-3640 $/kW, 63 percent more expensive than base plant without capture. • NGCC: 1490 $/kW, 97 percent more expensive than base plant without capture. **Cost of CO2 Avoided (PO:1,2)** • Supercritical PC: 54-55 $/tonne • NGCC: 76 $/tonne **O&M Cost (PO1)** • Supercritical PC: 1.60 ¢/kWh, 113 percent more expensive than base plant without capture. • NGCC: 0.68 ¢/kWh, 74 percent more expensive than base plant without capture. **Total Levelized Cost (PO:1,2)** • Supercritical PC: 10.2 ¢/kWh, 65 percent more expensive than base plant without capture. • NGCC: 8.5 ¢/kWh, 41 percent more expensive than base plant without capture.
Emissions	**CO2** • Depending on how much carbon capture is employed plants with this technology will emit little to no CO2. **Criteria Pollutants** • Plants using this technology will emit low criteria emissions, especially since NOx and SOx concentrations in the flue gas must be low before entering the CO2 absorber. Depending on the flue gas composition exiting the conventional emission controls, supplemental NOx reduction and SO2 removal systems may be required (PO1).

Source: Navigant Consulting, Inc.

Geological Sequestration

Depleted and active oil and gas fields rank at the top of the list as storage sites in the near future, due to existing knowledge and infrastructure and better economic viability than other options. Additionally, these formations have been proven to hold gases and fluids over very long periods. Sequestered CO2 could be used to enhance the recovery of oil and gas from fields, which would otherwise be abandoned, thus increasing economic viability of storage projects. Primary recovery of oil fields usually yields about a quarter of the available oil because as oil is extracted the pressure of the well drops. Injecting a fluid (water or liquefied natural gas) into an oil field to boost the pressure and thereby achieve greater levels of extraction is common practice in oil production, known as enhanced oil recovery (EOR). The use of CO2 in EOR is proven as industry has been using CO_2 injection for enhanced oil recovery since the early 1970s. However, there are concerns about the local environmental impacts and the permanence of storage.

Worldwide storage capacity of oil and gas fields is estimated at 1140 Gt of carbon(GS1), within the United States the conservative estimated storage capacity in oil and gas fields is 140 Gt of carbon, in unmineable coal seams the estimate is 160-180 Gt carbon, in deep saline formations the estimate is 3,300-12,600 Gt of carbon (GS4).

If storage is poorly sited or executed, there could be leakage that undermines the climate benefit – this is true for any type of storage. The presence of old wells at EOR sites is a major concern because they are sealed with concrete that may eventually fail and represent potential leakage pathways. CO_2 is dangerous to humans and animals in high concentrations, causing asphyxiation at high enough levels. Slow leaks can accumulate in confined spaces enough to be dangerous to humans, but even seeping gradually into the soil can be damaging to plants. Although the amount of oil recovered is increased in EOR, capture and storage require the use of more fuel to yield the same energy, which would tend to increase extraction needs.

For storage purposes, CO_2 has to be injected to a minimum of 800 -1,000 meters depth, where pressure and temperature turn it into a supercritical liquid. CO_2 can be injected into geological formations to enhance not only oil recovery, but also natural gas recovery and methane recovery from unminable coal seams.

Enhanced oil recovery may be a strategy to increase the economic viability of storage projects. For EOR/Storage to succeed, the priorities of the CO_2 supplier and the oil producer must be brought into closer alignment. Table 72 below lists the key characteristics of geological sequestration.

Table 72. Geological Sequestration Technology Characterization

Technology Characterization – Geological Sequestration	
Benefits	**Effective Recovery Medium** – For EOR applications beyond a certain minimum pressure level CO2 will dissolve into the oil, decreasing its viscosity and allowing the oil to flow more freely. Also, because CO2 is heavier than natural gas, it can be injected to deeper levels and will spread more widely in EOR applications. **Experienced Technology** – EOR operations involving CO2 started in Texas in 1972. The formations into which the CO2 is are injected have been studied extensively by industry for exploration purposes and their characteristics are known. Moreover, there is experience with storing natural gas in depleted fields and other geological formations. **Increased oil production** – CO2 storage as an additional incentive for EOR operations could have a significant impact on oil production. Typically, only about one-third of the oil discovered can be produced economically. This already includes secondary oil recovery mechanism, such as the injection of water. CO2 injection for tertiary recovery could push this to substantially higher average recovery efficiency approaching 50 percent. **Additional Oil Revenue**– If storage is combined with EOR at mature or nearly depleted fields, the cost associated with storage of CO2 may be reduced or significantly subsidized by the increased oil revenue.
Cost	The cost of storing the CO2 represents a small share of the total cost of capture, transportation, and storage (20-35 percent): Capturing the gas is the most expensive part. Storage costs could be lower for oil and gas fields than for saline aquifers, oceans, or coal beds because some of the necessary infrastructure and knowledge is already available. Reopening abandoned fields would, however, incur higher cost than using active or near-end fields because of infrastructure reinstallation, redrilling cost, and potential influx of reservoir water in the meantime. The use of anthropogenic CO2 for EOR has not been considered to be economically viable, due to the extra cost (compared to tapping a natural source) associated with capturing a sufficiently pure CO2 stream from a plant. The current practice of CO2 EOR differs from a CO2 storage approach in that it aims at minimizing CO2 use for cost reasons. The combination of CO2 storage with fossil fuel extraction, therefore, faces the dilemma that the two sides of the EOR equation (the CO2 supplier and the oil producer) have somewhat opposing priorities, if the two are not part of the same operation. To bring these two together, intermittent storage may be necessary, which could increase cost considerably (GS1). **Cost of CO2 Avoided** • The IEA estimates in a 2002 report between 5 and 21 $/ton-CO2 for transport and storage combined, depending on transport distance and storage method (GS1). • Transport on its own is estimated to cost between 1 and 3 $/ ton-CO2 per 100 km of distance covered (GS1). • A 2002 study in the Netherlands arrived at 1-8 $/ton-CO2 avoided (excl. transport cost) for injection into gas fields and −10 to 10(20) $/ton-CO2 avoided for on(off)shore oil yields (negative cost result from oil revenues). • While prices fluctuate with the price of oil, in recent years, EOR operations in other states have valued CO2 at around $20 per metric ton (GS2). • The cost figures as well as the potential capacity estimates have to take into account that there is an energy penalty from CO2 capture, and additional emissions are created in the process. Avoided CO2 emissions have to be discounted, as it were, by this amount: at a 25 percent penalty, a tonne injected isn't a tonne avoided, but rather only 800 kg. In the case of the combination of CO2 storage with fuel extraction, the CO2 that is extracted along with the oil for example,also has to be subtracted for the purpose of calculating emission avoidance (GS1).
Status	So far, commercial CO2 injection into oil fields has only been carried out for EOR purposes, not on storage grounds. The United States is the world leader in enhanced oil recovery technology, using about 32 million tons of CO2 per year for this purpose.(GS3) In nearly all of the existing CO2 EOR cases, the CO2 used is from naturally occurring CO2 reservoirs and not from anthropogenic fossil fuel combustion, as envisaged by storage proponents.(GS1) Additionally, there are a number of pilot-scale demonstration and research projects on CO2 sequestration in geological formations being sponsored by the US DOE.

Source: Navigant Consulting, Inc.

3.2.3. Advanced Nuclear Power Generation

The key takeaways from profiles on advanced nuclear power generation are:

- Various advanced nuclear power technologies (ABWR and APWR) are competing for combined construction and operating licenses and be the first nuclear reactor built in the United States over the last 20 years.
- The earliest a new nuclear reactor could be operational in the United States would be about 2016.
- Cost of building an advanced nuclear power plant in the United States is highly uncertain given that no nuclear power plants have been built recently.
- There is still no facility for nuclear waste disposal.
- Existing research abroad (for example, China) is focused on early stage modular technologies.
- California's moratorium on building new nuclear power generation would have to be lifted to allow for new nuclear power.

Nuclear power is the controlled use of nuclear reactions to release energy for the generation of electricity. Nuclear energy is produced when a fissile material, such as uranium-235, 235U, is concentrated such that nuclear fission takes place in a controlled chain reaction and creates heat, which is used to boil water, produce steam, and drive a steam turbine. (AN18)

Advanced nuclear reactors run on Uranium-235 and range in size from 100 – 2000 MW (AN18).

Types of advanced nuclear reactors are:

- AP1000 – pressurized water reactor; size: 1117-1154 MWe (AN19).
- ABWR – (Advanced Boiling Water Reactor) size: 1371-1465 MWe (AN19).
- ESBWR – (Economic Simplified Boiling Water Reactor) size: 1550 MWe plus (AN19).
- EPR – (European Pressurized Reactor) size: 1600 MWe (AN19).
- APWR – (Advanced Pressurized Water Reactor) size: 1600 Mwe (AN19).

Efficiencies of advanced nuclear reactors are about 33 percent (AN18).

Advanced nuclear power generation is attractive due to zero emissions, and cost-competitive with fossil-fueled plants. However, advanced nuclear power generation is not viable in California due to the moratorium set forth in Public Resources Code 25524.1-2. Table 73 below lists the key characteristics of advanced nuclear power technologies.

Table 73. Advanced Nuclear Power Technology Characterization

Technology Characterization – Advanced Nuclear Power	
Cost	For a 1000 MW plant : **Total Installed Cost ($/kW)** • $2,865/kW (AN18) **O&M Cost ($/kWh)** • $4.86/kWh (AN18) • $136/kW (AN18)
Emissions	No emissions (AN18)
Benefits	• The AP1000 was designed to reduce capital costs and to be economically competitive with contemporary fossil-fueled plants (AN20). • Nuclear power plants do not pollute the air with nitrogen oxides, sulfur oxides, dust or greenhouse gases like carbon dioxide (AN21).

Source: Navigant Consulting, Inc.

4.0 Key Trends and Issues

There are a series of trends and issues that could have great impact on advanced generation technologies in California. These issues include:

- Future Resource Mix
- Repowering and Replacing Power Plants
- Integrated Power Generation and Desalination
- Abundant, Affordable, Reliable, and Sustainable Electricity Supply
- Integration of Distributed Generation to a Smart Grid
- Intermittency of Renewable Generation
- Integrated Distributed Generation (for example, Solar + CHP) in Zero Net Energy Buildings
- Natural Gas Supply

4.1. Future Resource Mix

A recent study[25] to support the *2009 IEPR* found that generation from natural gas could be reduced 15 percent by 2020 under existing state energy policy. For electricity generation, the Western Electricity Coordinating Council (WECC) wide amount of natural gas did decrease in both full Scoping Plan cases by 15 percent, due to the contributions of energy efficiency, rooftop PV, renewables, and CHP. However, reductions were not distributed evenly; more than half of the gas reductions occurred out-of-state. In-state gas-fired generation went down only by 10 percent in the High Wind case and 12 percent in the High Solar case when compared to the Reference case in 2020. This suggests that out-of-state natural gas is the marginal source and that in-state gas is used for local reliability or ancillary services.

4.2. Repowering and Replacing Power Plants

The state is reviewing the goal to replace 17,000 MW from aging natural gas plants by 2012 to meet repowering and replacement goals. As part of the *2004 Energy Report Update*, the Energy Commission identified a group of older, larger power plants with relatively high heat rates (low efficiencies) and relatively high operation (capacity factors) for repowering and/or replacement. This group of 66 aging gas-fired power plants with a combined capacity of 17,000 MW represents 40 percent of in-state gas-fired power plants and 25 percent of all in-state capacity. In the *2005 Energy Report*, the Energy Commission recommended that the state's utilities undertake long-term planning and procurement that will allow for the orderly retirement or repowering of the aging power plants in this study group by 2012.

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[25] Source: Tanghetti, Angela, Karen Griffin, 2009. *Impacts of AB 32 Scoping Plan Electricity Resource Goals on Natural Gas-Fired Generation*. California Energy Commission. CEC-200-2009-011.

There are still a series of issues that will need to be address to meet the repowering and replacement goals:

- Utilities are concerned about operational issues, including the replacement of aging power plants with renewables located at a distance from load centers, and whether the full set of transmission line additions needed to support this pattern of resource build-out has been adequately assessed
- Retirement by 2012 creates timing issues with the build-out timeline for energy efficiency and renewables
- Local capacity requirements adopted by the California Public Utility Commission (CPUC) and the California Independent System Operator (California ISO) constrain choices
- California ISO proposed a broad transmission study for retirements

4.3. Integrated Power Generation and Desalination

Improvements have lessened the thermal and pumping energy required for the desalination processes, but the energy intensity remains high. Figure 4 below illustrates the energy intensity of desalination relative to other sources.

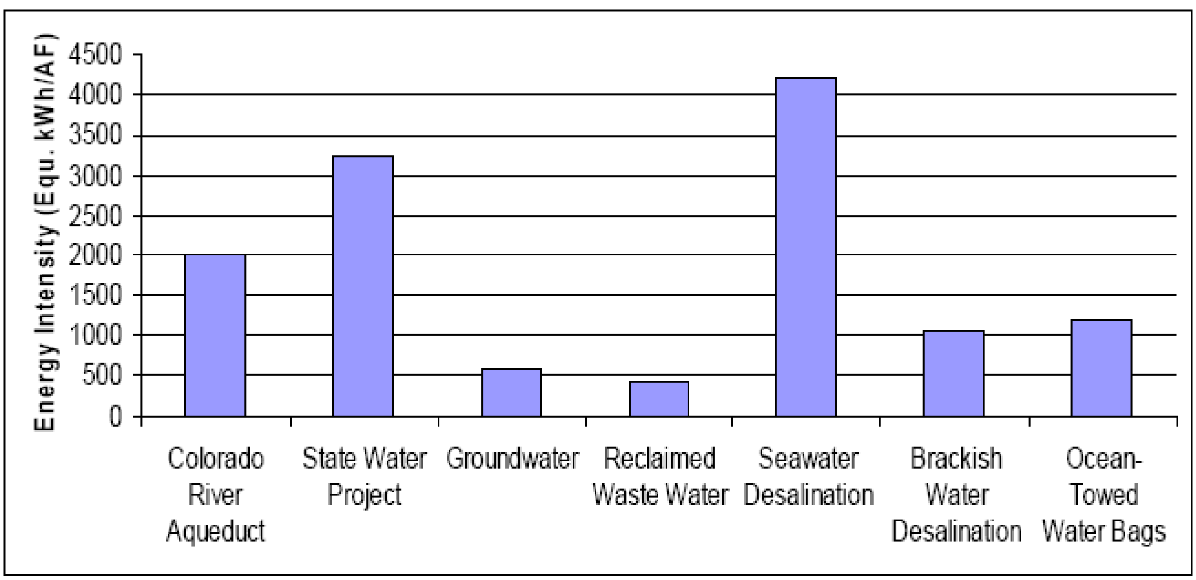

Figure 4. Sources and Conveyance Energy Intensity for San Diego County

Source: Pacific Institute. *A Preliminary Statewide Assessment of Water-Related Energy Use and Some Implications for Energy Efficiency Programs, 2005*

Energy and greenhouse gas emissions impacts will need to be considered when assessing desalination projects. California's water systems are uniquely energy-intensive due in large part to the pumping requirements of major conveyance systems, which move large volumes of water long distances and over thousands of feet in elevation. As California confronts a limited water supply, 20 desalination plants have been proposed statewide. The San Diego Regional Water Quality Control Board recently approved the biggest seawater desalination plant in the Western Hemisphere, a $300 million facility, that will produce 50 million gallons of drinking water daily, enough for 110,000 households. The plant is expected to begin operations by the first quarter of 2012.

Desalination facilities may make more economic sense in areas that have high energy and treatment costs for their current water supplies, like Southern California's urban areas. NRDC research has demonstrated that significant opportunities for energy savings may be realized by reducing the need for the most energy-intensive supplies, through implementation of water use efficiency, water recycling, and reusing urban runoff through low-impact development (LID). NRDC recommends to move beyond the water benefits of measures and ensure that they are implemented in a way that maximizes their energy savings and greenhouse gas reduction potential.

R&D is guided by the Desalination and Water Purification Technology Roadmap 2003 (US Bureau of Reclamation and Sandia National Laboratories 2003) and subsequent roadmap reviews.[26]

4.4. Abundant, Affordable, Reliable, and Sustainable Electricity Supply

California has significant electricity resources that are cleaner but less affordable than the U.S . average.

Abundant

In 2007, California had:

- Total retail sales of 264,234 GWh, the second highest state.
- Net summer capacity of 63,813 MW, the second highest state.
- Net generation of 210,847 GWh, the fourth highest state.

Affordable

In 2007, California's average electricity price was 12.80 cents/kWh, the tenth highest state and 40 percent above the national average of 9.13 cents/kWh.

[26] Sources for Section 4.4: *2005 IEPR*, NRDC Comments on Water in Draft Scoping Plan and Appendices, Poseidon press release.

Reliable

In 2007, the Western Electricity Coordinating Council (WECC) had a capacity margin of 18.8 percent as compared to a contiguous U.S. average capacity margin of 16.5 percent.

Sustainable

In 2007, California's emissions of carbon dioxide from electricity generation were 656 lbs/MWh, the 46th lowest state and 50 percent below the national average of 1,335 lbs/MWh.[27]

4.5. Integration of Distributed Generation to a Smart Grid

The smart grid is expected to increase the value of PV and other distributed generation systems.

Does the PV-Smart Grid create value? *Yes*

Does the Smart Grid enable higher penetration of PV? *Yes*	Does the Smart Grid help PV provide grid benefits? *Yes*	Does the PV-Smart Grid create Business Opportunities? *Yes*
• Challenges for high penetration of PV include: 1. T&D technical, 2. communications and 3. regulatory/business models • Coupled with energy storage, the Smart Grid (AMI and DA) can address important T&D challenges: Voltage Regulation, Reverse Power Flow, and Power Fluctuations (Frequency Regulation) • By addressing these challenges Smart Grid infrastructure could result in higher net metering caps, better interconnection standards and more prevalent time of use tariffs options. These changes could increase PV market penetration by over 60% by 2020	• PV-Smart Grid could result in several billion in additional benefits by 2020, depending on use of energy storage. • Most of the additional benefits come from energy savings associated with high penetrations of PV, and the firming of capacity that can be achieved with integrated energy storage • A smaller share of additional benefits can be classified as "grid benefits", and are created by the coordinated control of high penetrations of PV, especially when it is concentrated in specific pockets	• PV Smart Grid has a benefit-cost ratio greater than 1.0 • The most promising opportunities resulting from the PV Smart Grid are: –*DG PV Power Plant*, which could be implemented in the near term (3-5 years) –*Smart Capacity Firming*, likely to unfold in medium term (5-10 years), unless energy storage breakthrough earlier. –*Distribution Optimization*, requires broad implementation of Smart Grid; Likely to unfold in medium term (5-10 years), given complexity

Figure 5. Value Chain of PV Smart Grid

Source: Navigant Consulting PV Smart Grid Multi Client, 2009.

Realizing the expected value will require coordinated involvement of various stakeholders.

Utility Implications

With PV-smart grid, utilities could relax existing restrictions on high penetration of PV without compromising grid performance. High penetrations of PV within a smart grid can produce a modest level of grid benefits. Grid benefits are further improved if utilities own PV or can influence siting in constrained areas. Implementation will require testing and experimentation to ensure that the benefits can be realized on a large scale; carefully crafted pilot programs will

[27] Sources: Energy Information Administration, *Electric Power Annual 2007* (published January 2009).

be critical. These opportunities may allow utilities to expand their asset bases while delivering high levels of service for their customers.

Policy/Regulatory Implications

New rate and revenue recovery mechanisms are needed to realize the benefits defined, particularly for benefits such as voltage regulation and power quality, which are difficult to quantify. TOU rates are useful for unlocking value and will be enabled by the smart grid. IEEE 1547 and other technical standards must be enhanced to enable PV to operate for grid support. Extension/inclusion of state/federal rebates and ITC for integrated PV energy storage (ES) systems are needed.

Investor Implications

Energy storage could benefit from additional R&D investment to develop technologies that combine price and performance characteristics in sizes that are appropriate for PV (for example, flow batteries at smaller sizes for residential applications). New inverters that can be utility-controlled to provide grid benefits could create a significant value opportunity.

4.6. Intermittency of Renewable Generation

Intermittency of renewable generation is a key challenge for the state in meeting RPS goals. The key technical integration issues involve a lack of multi-megawatt, multi-hour energy storage and challenges in grid operation and performance. The major non-technical hurdles involve the high first cost of some renewable energy technologies. A review of key policy and technical documents, among others, revealed energy storage, renewable resource forecasting, and transmission/grid operations as potentially the best means to ease the integration of renewable energy resources at the utility scale. PIER is developing a roadmap, similar to the advanced generation roadmap, to guide RD&D efforts to overcome these integration challenges.

Table 4-1: Resource Mix Scenario for Intermittency Analysis Project (33 Percent Renewable Energy by 2020)	2020
Total Geothermal, MW	5,100
Total Biomass, MW	2,000
Total Concentrating Solar, MW (Intermittent)	3,100
Total Photovoltaic Solar, MW (Intermittent)	2,900
Total Wind, MW * (5,800 MW in Tehachapi Region) (Intermittent)	12,700
Total Renewable Capacity	25,800
Peak California Load, MW	80,742
Peak California ISO Load, MW	66,700
Intermittent Penetration in CA	23%
Intermittent Penetration in California ISO Service Territory	25%
Total Renewable Resource Penetration in California	32%

Figure 6. Resource Mix Scenarios for Intermittency Analysis

Source: California Energy Commission, *Intermittency Analysis Project: Summary of Final Results*, CEC-500-2007-081, Table 2-2, p-18. [www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.pdf].

4.7. Integrated Distributed Generation in Zero Net Energy Buildings

In October 2007, the CPUC issued a ruling consisting of three elements that will have dramatic impact on energy efficiency and distributed generation. The CPUC ruling consists of three programmatic initiatives:

1. All new residential construction in California will be zero net energy by 2020.
    a. Specifies zero net energy rather than "zero net carbon" because energy is in line with CPUC jurisdiction and expertise.
    b. Interim goal of 50 percent of new single-family homes to achieve Tier 2 standards of California Energy Commission's New Solar Homes Program by 2011.
2. All new commercial construction in California will be zero net energy by 2030.
    a. Specifies zero net energy rather than "zero net carbon."
    b. Consistent with AIA 2030 challenge.
3. HVAC industry will be reshaped to ensure optimal equipment performance.
    a. More nebulous goal than others.

b. Notes 3 issues:
   i. Widespread disregard for Title 24 permitting and standards.
   ii. Need climate appropriate technologies and other new technology solutions.
   iii. Need for holistic "whole building solutions."

4.8. Natural Gas Supply

Estimates regarding natural gas supply vary. Some reports suggest that limited natural gas deliverability and supply scarcity are misconceptions, and supply scarcity claims are refuted by recent market growth and projections.

Supply Scarcity Debunked

The assumption that the industry cannot or will not bring forth the deliverability needed to serve new, expanded markets is completely refuted by the remarkable growth of deliverability over the last several years. Added U.S. onshore domestic natural gas deliverability has exceeded the thermal content of all our imports from Saudi Arabia. Producer estimates of shale deliverability within the next decade (assuming a healthy consuming market) indicate that it could increase U.S. gas supplies by some 30 percent. That is enough natural gas to displace either a large share of U.S. vehicle fuel or more than half of the coal used to generate power. Even if the sharp ramp-up in deliverability that producers indicate is feasible right now and over the next couple of decades is used, the known resource would still last over 70 years. And that recoverable resource base is a moving target, simply the share of the much larger "gas in place" determined to be recoverable with current technology.

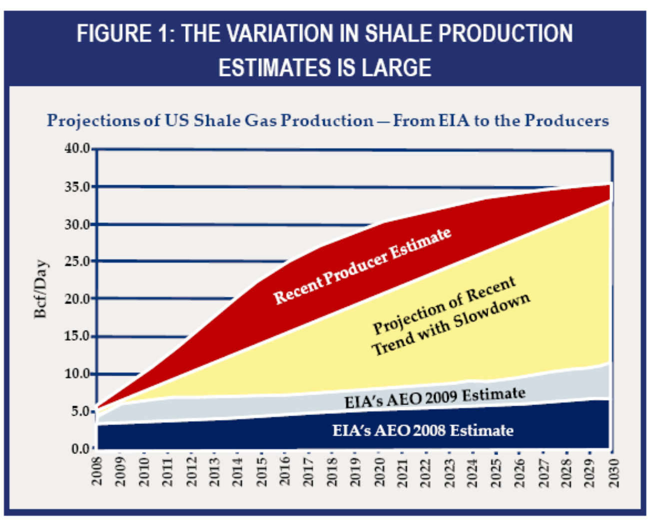

Figure 7. Projection of U.S. Shale Gas Production

Source: *NGMarket notes*, A publication by Navigant Consulting's Energy Practice, June 2009; "Economic Realities from the Natural Gas Market" Pickering, Gordon. *The Source*, May 2009.

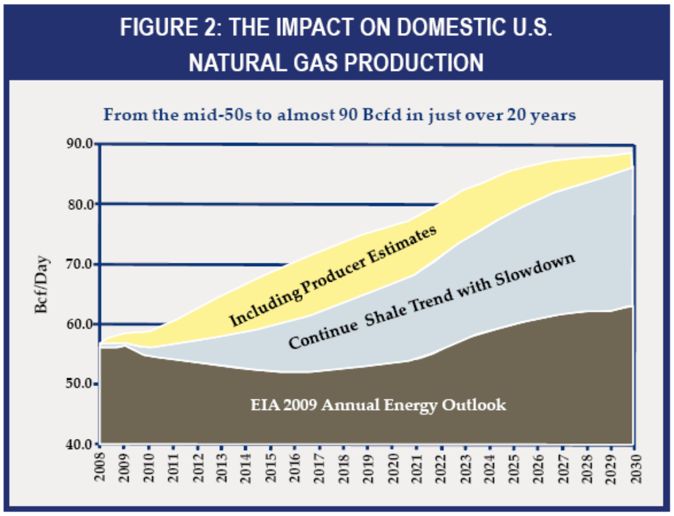

Figure 8. The Impact on Domestic U.S. Natural Gas Production

Source: *NGMarket notes*, A publication by Navigant Consulting's Energy Practice, June 2009; "Economic Realities from the Natural Gas Market" Pickering, Gordon. *The Source*, May 2009.

Given the U.S.'s abundant supply, natural gas can play an immediate and important role in reducing CO2 emissions by replacing coal. Following the release of last year's *North American Natural Gas Supply Assessment* for the American Clean Skies Foundation, many leading industry experts have evolved to a perception of supply abundance. Production from the major gas shale has increased on an exponential curve over the past 10 years, and the estimates of recoverable shale gas continue to grow.

The United States has a lot of domestic natural gas supply, both in terms of the deliverability that can be developed in the near term and in terms of the ultimate resource that will define the life of that deliverability. Given this supply, the role natural gas could play in immediately reducing carbon dioxide by displacing older, less efficient coal power generation is clear, and the role natural gas could play to displace foreign oil use in vehicle fuel over the next decade is equally clear. However, this reality doesn't appear to be apparent or at least embraced by key policy makers.

There are three areas of questions/issues/misperceptions surrounding natural gas that are keeping it from moving to the front of the policy queue:

- Supply Perception – Despite overwhelming evidence to the contrary, many policy makers still seem to perceive natural gas as a scarce resource.
- Environmental Perception – Because natural gas is so frequently addressed in concert with oil, the general resistance to domestic drilling creates a general resistance to relying on domestic natural gas.
- New-solution Trendiness – Natural gas is a longstanding resource that is cleaner than all other fossil fuels, but policy makers want to go directly to the "final solution" of zero-carbon renewables.

5.0 Strategic Opportunities

The PIER AG roadmap framework consists of four elements: vision, program areas, key research issues, and issues outside program scope.

Roadmap Framework

- **Program Vision**
  The vision that the PIER AG program should strive to achieve.
- **Program Areas**
  Recommended target research areas and organizational structure for the PIER AG program.
- **Key Research Issues**
  For each program area, the technology, regulatory, and market research issues that the PIER AG program should focus on.
- **Other Research Issues**
  The research issues that the PIER AG program should not necessarily focus on but could provide support to other PIER research areas addressing such issues.

5.1. Program Vision

The new program vision enables PIER AG to play a key role in helping the state meet key policy goals.

2020 PIER Advanced Generation Vision

The PIER AG program provides key RD&D that enables California to generate energy efficient, abundant, affordable, reliable, and environmentally friendly electricity (and other forms of power) from small to large power plants, including distributed generation and combined heat and power, using clean non-renewable fuels, and fuel flex capability helping reach the greenhouse gas emission reduction targets.

5.2. Program Areas

PIER AG would focus on improving efficiency and reducing GHG emissions of large-scale and distributed generation systems fueled with natural gas and fuel flexible. Three main program areas are:

- Commercial CHP/CCHP Systems – Support development of cost-effective CHP and CCHP systems for commercial buildings and their widescale deployment.
- Industrial CHP/Cogeneration Systems – Support development of cost-effective industrial CHP/cogeneration systems and their widescale deployment.

- Advanced Gas Turbine Cycles – Support development and widescale adoption of cost-effective advanced gas turbine cycles, including integrated hybrid renewable systems that significantly improve the efficiency and fuel flexibility of natural gas power plants.

5.3. Key Research Issues

In each target research area, PIER AG should focus on a few key research issues.

- Commercial CHP/CCHP Systems
    - System packaging and integration (primary)
    - Market and regulatory mechanisms (secondary, complement the Energy Commission's CHP program)
- Industrial Cogeneration Systems – Support development of cost-effective industrial cogeneration systems and their widescale deployment.
    - System packaging and integration (primary)
    - Identification of cost-effective sites (secondary, complement the Energy Commission's CHP program)
    - Market and regulatory mechanisms (secondary, complement the Energy Commission's CHP program)
- Advanced Gas Turbine Cycles – Support development and widescale adoption of cost-effective advanced gas turbine cycles that significantly improve the efficiency of natural gas power plants.
    - New technology development of integrated hybrid renewable cycle systems (primary)
    - New technology demonstration of advanced generation technologies (primary, channel US DOE resources to California)
    - Market and regulatory mechanisms (secondary, support policy development)

5.4. Other Research Issues

PIER AG will have to focus its limited resources and avoid duplication of efforts and funding research addressed by other PIER research areas. However, PIER AG will continue coordinating and providing support to other PIER research areas addressing specific research issues as their main focus but related to PIER AG research issues. For example:

- Residential single family CHP/CCHP Systems – Technologies currently not cost-effective as thermal load too small relative to electricity load. Continue to monitor technology progress as there is a high technical potential for residential CHP/CCHP systems.

- DG systems primarily used for emergency baseload, peaking, backup, and cycling applications – Primary focus on more efficient, cost-effective, and environmentally friendly CHP systems.
- DG/CHP interconnection rules and standards – Addressed by Smart Grid research area of the PIER Energy Systems Integration program.
- Renewables, including management of intermittency issues through the co-location of renewable systems and traditional gas fueled generation systems – Addressed by the PIER Renewable Energy Technologies program.
- Water use in power plants, including replacement technologies for once-through cooling − Addressed by the PIER Environmental Area and PIER Industrial/Agricultural/Water End ‐ Use Energy Efficiency program.
- Carbon capture and sequestration – Primarily focused on coal-fueled generation and addressed by US DOE. Continue to monitor cost-effectiveness of application to natural gas fueled power generation as under WestCarb Program and relevant to California.
- Nuclear – Moratorium still in place. Continue monitoring advances in the nuclear technology.

6.0 PIER Advanced Generation Program Roadmap Development Process

The PIER Advanced Generation roadmapping project is expected to run through September 2009 and include several stakeholder WebEx and in-person workshops. Figure 9 below shows the timeline of the roadmapping process.

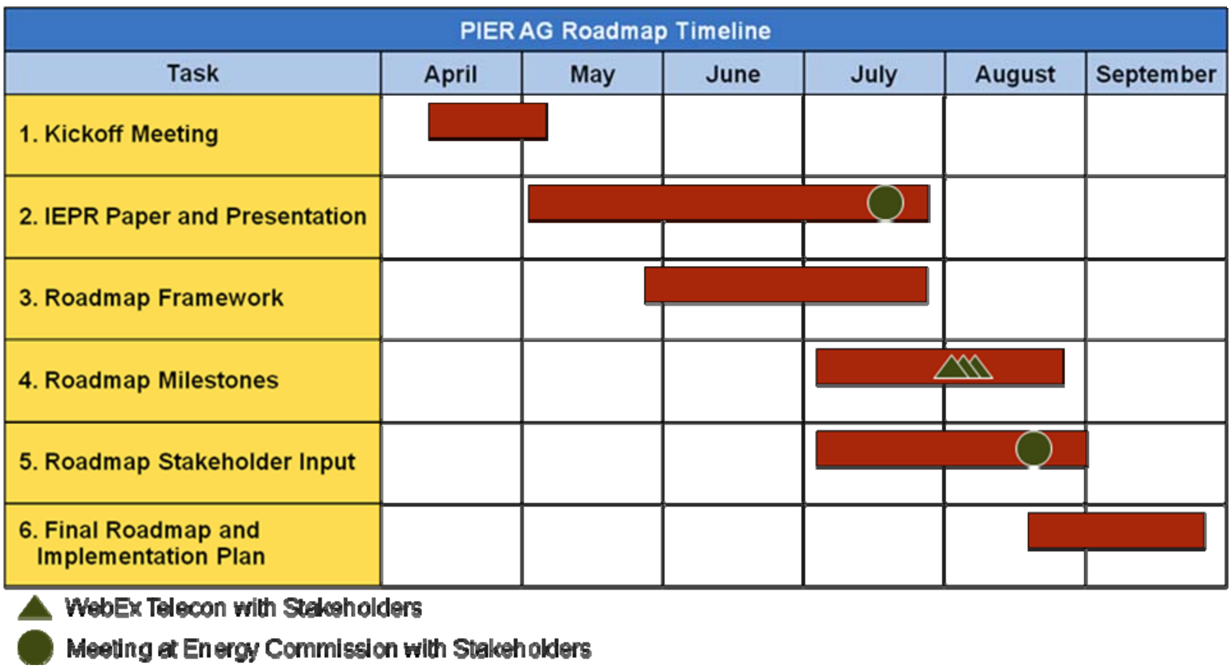

Figure 9. PIER AG Roadmap Timeline

Source: Navigant Consulting, Inc.

Stakeholder input is a critical element of the roadmap development process. Expertise in advanced generation technologies is widely spread across various stakeholder groups, including utilities, equipment manufacturers, research organizations, and policy makers. The roadmap development process involves seeking input from various stakeholder groups. The *2009 IEPR* staff workshop on advanced generation is part of this process to obtain input from stakeholders participating in this workshop.

The *2009 IEPR* process will culminate in the publication of the final report later this year. Research to support the *Integrated Energy Policy Report* is ongoing. Staff and committee workshops, open to the public, to present and discuss policy research and policy recommendations will take place from June to September 2009. A draft *2009 Integrated Energy Policy Report* will be released in September 2009. Finally, the final version of *2009 Integrated Energy Policy Report* will be adopted in November 2009.

7.0 Appendix

7.1. Glossary

Acronym	Definition
ACC	Air-cooled condensers
AIA	American Institute of Architects
ARRA	American Recovery and Reinvestment Act of 2009
AB1613	Assembly Bill 1613
AB 32	Assembly Bill 32
ABWR	Advanced boiling water reactor
AFC	applications for certification
AMI	advanced metering infrastructure
AP1000	Advanced Passive 1000
APWR	Advanced pressurized water reactor
ARB	California Air Resources Board
BCHP	Packaged cooling, heating, and power systems for buildings
Btu	British thermal unit
°C	degrees Celcius
CA	California
CaFCP	California Fuel Cell Partnership
California ISO	California *Independent System Operator*
CCHP	combined cooling heat and power
CCS	carbon capture and sequestration
CEMS	continuous emission monitoring systems
CFB	circulating fluidized bed
CHP	combined heat and power
CI	compression ignition
CO	carbon monoxide

CO2	carbon dioxide
COE	cost of electricity
COP	coefficient of performance
CPUC	California Public Utilities Commission
CSLF	Carbon Sequestration Leadership Forum
CSP	concentrated solar power
CT	combustion turbines
CTC	competitive transition charges
DA	Distributed automation
DCC	double condenser coupled
DER	distributed energy resources
DG	distributed generation
DLE	dry low emissions
DLN	dry low NOx
DR	demand response
EAP I	*Energy Action Plan I*
EAP II	*Energy Action Plan II*
Energy Commission	California Energy Commission
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
EPR	European Pressurized Water Reactor
EPRI	Electric Power Research Institute
ESBWR	Economic simplified boiling water reactor
°F	degree Fahrenheit
FCT	fuel cell/turbine
FOA	Funding Opportunity Announcement
FY	fiscal year
GE	General Electric Company

GEF	Global Environment Facility
GHG	greenhouse gas
Gt	gigaton; one billion tons
GTI	Gas Technology Institute
GW	gigawatt
GWh	gigawatt-hour
H2	molecular hydrogen
H2O	hydrogen dioxide; water
HHV	high heating value
HRSG	heat recovery steam generator
IC	internal combustion
IEEE	Institute of Electrical and Electronics Engineers
IEPR	*Integrated Energy Policy Report*
IGCC	integrated gasification combined cycle
IGSC	integrated gasification simple cycle
IOU	investor-owned utility
IRC	intercooled recuperated gas turbine cycle
ISCCS	integrated solar combined cycle system
ISO	independent system operator
ITC	Federal Business Energy Investment Tax Credit
k	thousand
kW	kilowatt
kWh	kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LCE	levelized cost of electricity
lbs	pounds
LFG	landfill gas
LHV	low heating value

LID	low impact development
LNG	liquefied natural gas
MACRS	Modified Accelerated Cost-Recovery System
MCFC	molten carbonate fuel cell
MM	million
MMBtu	million British thermal units
MOU	memorandum of understanding
MW	megawatt
Mth	million therms
MWe	megawatt electric
MWt	megawatt thermal
MWh	megawatt-hour
NETL	National Energy Technology Laboratory
NG	natural gas
NGCC	natural gas combined cycle
NO2	nitrogen dioxide
NOx	nitrous oxides
NPDES	National Pollutant Discharge Elimination System
NRDC	Natural Resources Defense Council
NYSEG	New York State Electric and Gas
NYSERDA	New York State Energy Research and Development Authority
O2	molecular oxygen
O&M	operations and maintenance
OEM	original equipment manufacturer
OIT	Oregon Institute of Technology
ORC	organic Rankine cycle
ORNL	Oak Ridge National Laboratory
OTC	once-through cooling

PA	phosphoric acid
PAFC	phosphoric acid fuel cell
PC	pulverized coal
PEM	polymer exchange membrane
PEMFC	polymer exchange membrane fuel cell
PHEV	plug-in hybrid electric vehicle
PIER	Public Interest Energy Research
PIER AG	Public Interest Energy Research Advanced Generation Program
PIER EA	Public Interest Energy Research Environmental Area
PM2.5	particulate matter 2.5 micrometers of less in diameter
PM10	particulate matter 10 micrometers of less in diameter
POGT	partial-oxidation gas turbine
POU	publicly owned utility
ppm	parts per million
ppmvd	parts per million volumetric dry
psi	pounds per square inch
psig	pounds per square inch gauge
pt.	point
PV	photovoltaic
R&D	research and development
RD&D	research, development, and demonstration
REC	renewable energy credit
rpm	rotations per minute
RPS	Renewables Portfolio Standard
RWQCB	California Regional Water Quality Control Board
SB1250	Senate Bill 1250
SB 1368	Senate Bill 1368
SC CFBC	supercritical circulating fluidized bed combustion

SCR	selective catalytic reduction
SECA	Solid State Energy Conversion Alliance
SETP	Solar Energy Technology Program
SI	spark ignition
SNG	substitute natural gas
SO2	sulfur dioxide
SOFC	solid oxide fuel cell
SOx	sulfuric oxides
SWRCB	California State Water Resources Control Board
T&D	transmission and distribution
TIC	turbine inlet cooling
TOU	time of use
UCI	University of California-Irvine
USC PC	ultra supercritical pulverized coal
US DOE	United States Department of Energy
USFCC	US Fuel Cell Council
VAR	volt-ampere reactive
VOC	volatile organic compound
WECC	Western Electricity Coordinating Council
yr	year

7.2. Policy Documents

Relevant policy documents which were reviewed for background paper are listed below.

Table 74 lists the goals and directives from these documents.

7.2.1. State Policies

Policy Reports

- *Integrated Energy Policy Report* (2003, 2005, 2007 and 2008 update)
- Governor's Response to *2003 IEPR*
- *Energy Action Plan* (I, II, and 2008 update)

Governor's Executive Orders

- On greenhouse gas reduction (S-3-05)
- On renewable portfolio standard (S-14-08)
- Governor's Ten Point Electricity Plan

Enacted Bills

- SB 1078
- SB 1250
- SB 1368
- SB 107
- AB 32
- AB 1613
- AB 2791
- AB 811
- Public Resources Code 25524.1 and 25524.2

State Proposals

- ARB AB 32 Scoping Plan
- California Energy Commission Committee Report: CEQA Responsibilities for GHG Impacts in Power Plant Siting
- Draft Energy Commission PIER-EA Discussion Paper: Environmental Justice
- PIER Overview of Environmental Justice Requirements
- PIER Electricity Research Investment Five Year Plan

7.2.2. Federal Policies

- Energy Policy Act of 2005
- Energy Independence and Security Act of 2007
- Energy Improvement and Extension Act of 2008
- American Recovery and Reinvestment Act of 2009

- Clean Water Act, Section 316(b)

Table 74: Key policy goals and directives

Policy	Type	Policy Text
2007 IEPR	Goals	**Natural Gas Power Plants** • Require investor-owned utilities to procure enough capacity from long-term contracts to allow for the orderly retirement or repowering of aging plants by 2012 (*2007 IEPR*, page 7) • California's aging power plants are extremely inefficient compared to current technologies that are 20 to 30 percent more efficient; these plants must be either re-powered or retired and replaced with cleaner technologies that operate at higher efficiency to contribute to AB 32 goals (*2007 IEPR*, page 35) • The CPUC's greenhouse gas emission performance standard for new long-term power contracts specifies a maximum rate of 1,100 pounds of CO2 per megawatt hour (*2007 IEPR*, page 30). • Senate Bill 1037 (Kehoe, Chapter 366, Statutes of 2005) requires the CPUC, in consultation with the Energy Commission, to identify all potentially achievable cost-effective electric and natural gas energy efficiency measures for the investor-owned utilities, set targets for achieving this potential, and review the energy procurement plans of the investor-owned utilities to ensure the use of cost-effective supply alternatives (*2007 IEPR*, page 82) **Distributed Generation** • Increase the efficiency levels of the building standards and combine them with on-site generation so that newly constructed buildings are net zero energy by 2020 for residences and 2030 for commercial buildings (*2007 IEPR*, page 99)
	Directives	**Natural Gas Power Plants** • Increase natural gas research and development for ways to advance energy efficiency for both consumers and power plants (*2007 IEPR*, page 9) • California's utilities adopt all cost-effective energy efficiency measures for natural gas, including replacement of aging power plants with new efficient power plants (*2007 IEPR*, page 9) • The Energy Commission, the CPUC, the California ISO, and other interested agencies such as the Ocean Protection Council, State Water Resources Control Board and South Coast Air Quality Management District should work together to complete the studies needed to better understand the impacts of retiring, repowering, and replacing aging power plants, particularly in Southern California (*2007 IEPR*, page 73) • Since 2003, California's energy policy has relied on the loading order to meet growing energy needs — first with energy efficiency and demand response; second, with renewable energy and distributed generation; and third, with clean fossil-fueled sources and infrastructure improvement (*2007 IEPR*, page 20) • In 2006, California enacted SB 1368 (Perata, Chapter 598,

Statutes of 2006), a law prohibiting utilities from making long-term commitments for electricity generated by plants that create any more CO2 than clean-burning natural gas plants create (*2007 IEPR*, page 25)

- As required by Senate Bill 1368 (Perata, Chapter 568, Statutes of 2006), the state has set a greenhouse gas emission performance standard for all new long-term investment in or purchases of baseload electricity generation by utilities. SB 1368 precludes new reliance on power plants with carbon emissions greater than 1,100 pounds per megawatt hour similar to those of a modern natural gas combined cycle power plant (*2007 IEPR*, page 66)
- Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006) requires that the Energy Commission determine the potential vulnerability of existing large baseload generation facilities — 1,700 megawatts or greater — to a major disruption due to plant aging or an earthquake (*2007 IEPR*, page 69)
- The South Coast Air Quality Management District (SCAQMD) recently adopted Rule 1309.1, which limits the use of priority reserve emission credits for power plants (*2007 IEPR*, page 72)
- Municipal-owned plants will only be given enough credits by SCAQMD to build projects which serve their native load (*2007 IEPR*, page 72)
- SCAQMD limited the total amount of credits available for in-district generation to 2,700 megawatts of generation (*2007 IEPR*, page 72)
- Natural gas efficiency is also a priority in the Energy Commission's natural gas research, development, and demonstration program (*2007 IEPR*, page 184)
- The Energy Commission and CPUC should adopt a "loading order" for natural gas resources, similar to the one in place for the electric sector. This will encourage utilities to seek out low-carbon fuels before conventional sources of natural gas, with the first priority being all cost-effective natural gas efficiency and solar resources, followed by renewable fuels like biomethane (*2007 IEPR*, page 187)

Carbon Sequestration

- The most likely way for coal plants to meet SB1368 is through the use of advanced coal technologies combined with geologic carbon sequestration (*2007 IEPR*, page 66)
- AB 1925 (Blakeslee, Chapter 471, Statutes of 2006), requires the Energy Commission and Department of Conservation to develop "recommendations for how the state can develop parameters to accelerate the adoption of cost-effective geologic sequestration strategies for the long-term management of industrial carbon dioxide" (*2007 IEPR*, page 66)
- Advanced coal technology with carbon sequestration is considered as a promising future low CO2 source (*2007 IEPR*, page 66)
- Because of the technological, economic, and regulatory barriers facing commercial-scale application of carbon capture and sequestration, the Energy Commission does not believe advanced coal with carbon sequestration will yield a significant amount of electricity generation in the 2020 time frame. It does, however, remain an important national, and international, research and commercialization priority (*2007 IEPR*, page 67)

Distributed Generation

Generation

- Combined heat and power facilities must provide a larger role in meeting California's electricity supply needs (*2007 IEPR*, page 184)

Integration (Interconnection, Tariffs, Distribution)

- Integrate distribution planning with other resource procurement processes to support the use of new low carbon resources and applications — renewables, demand response, efficient combined heat and power, distributed generation, energy storage, advanced metering infrastructure, and plug-in hybrid electric vehicles (*2007 IEPR*, page 7)

- Work with the CPUC to eliminate non-bypassable charges for combined heat and power and distributed generation and punitive standby reservation charges for distributed generation (*2007 IEPR*, page 8)
- Develop a methodology for estimating distributed generation costs and benefits (*2007 IEPR*, page 8)
- The CPUC continue the work of the "Rule 21" industry/utility collaborative working group to refine interconnection standards, provide third party resolution of interconnection issues, and streamline permitting (*2007 IEPR*, page 8)
- The state adopt greenhouse gas reduction measures and regulations which fully reflect the benefits of combined heat and power (*2007 IEPR*, page 8)
- The CPUC adopt a tariff structure to make distributed generation projects "cost and revenue neutral," while granting owners credit for system benefits, such as reduced congestion (*2007 IEPR*, page 8)
- The CPUC base self-generation program incentives on overall efficiency and performance of systems, regardless of fuel type (*2007 IEPR*, page 8)
- The CPUC adopt revenue-neutral programs which would allow high efficiency combined heat and power on an equal footing with bulk power from utilities (*2007 IEPR*, page 8)
- The *2003 IEPR* recommended that California "Create a transparent electricity distribution system planning process that addresses the benefits of distributed generation" (*2007 IEPR*, page 160)
- In October 2007, Governor Schwarzenegger approved Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007), which allows the CPUC to require utilities to purchase excess electricity from combined heat and power systems sized at 20 megawatts or less (*2007 IEPR*, page 161)
- The CPUC's self-generation program incentives should be based upon overall efficiency and performance of systems, regardless of fuel type (*2007 IEPR*, page 163)
- The CPUC should complete a tariff structure to make distributed generation and combined heat and power projects "cost and revenue neutral," while granting owners' credit for system benefits such as reduced congestion (*2007 IEPR*, page 163)
- The CPUC and the Energy Commission should work cooperatively to eliminate all non-bypassable charges for distributed generation and combined heat and power, regardless of size or interconnection voltage and standby reservation charges for distributed generation (*2007 IEPR*, page 163)

Water Use for Generation

- U.S. Environmental Protection Agency (U.S. EPA) in 2004 issued its 316 (b) Phase II rule to regulate once-through cooling systems for existing large power plants. The regulations established a series of "best technology available" options which created flexibility for facility owners to comply with the new regulations (*2007 IEPR*, page 70).
- In 2007, U.S. EPA suspended its 316(b) regulations for large existing power plants and advised the states to use "best professional judgment" on specific permit renewals and new applications, with a new rulemaking planned to begin in late 2007 (*2007 IEPR*, page 70)
- The Energy Commission will actively participate in the California ISO's study concerning aging power plants that use once-through cooling, with specific attention given to the challenges faced by the investor-owned and the publicly owned utilities in Southern California

		(*2007 IEPR*, page 74) **Other** • Require Southern California Edison to develop, as part of its long-term procurement plans, a contingency plan to replace generation from Palo Verde should it be shut down for an extended period (*2007 IEPR*, page 7) • Beginning in 2007, the California ISO identified the need for additional capacity in 2007 and 2008 in specific state geographic zones with constrained resources to meet local capacity requirements. For 2007, the existing capacity needed to meet these requirements is 22,113 megawatts across 10 zones, many of which are coastal urban areas with older steam boiler facilities (*2007 IEPR*, page 72)
***IEPR 2008* Update**	Goals	**Natural Gas Power Plants** • In 2003, California's principal energy agencies adopted a "loading order" that sets the priority for adding new energy resources to meet electricity use demands in the state: first is energy efficiency, second is renewable resources, third is distributed generation (electricity produced close to where it is used), and fourth is clean fossil fuel generation (*IEPR 2008 Update*, page 74) • The current assumption for PG&E is that aging plants in Northern California will be retired by 2015, while SCE assumes aging plants in Southern California will be retired by 2018 (*IEPR 2008 Update*, page 54) **Distributed Generation** • AB 1613 also requires the Energy Commission to develop CHP regulations for system size, efficiency standards, cost-effectiveness, technical feasibility, and environmental benefits by January 1, 2010 (*IEPR 2008 Update*, page 95) **Water Use for Generation** • In March 2008, the State Water Resources Control Board issued a draft proposal calling for the phased elimination of once-through cooling between 2015 and 2021 (*IEPR 2008 Update*, page 5) • More than 21,000 MW of the state's generation fleet uses once-through cooling (OTC), approximately 15,200 MW of which is aging capacity recommended for retirement in the *2005* IEPR (*IEPR 2008 Update*, page 58)
	Directives	**Natural Gas Power Plants** • Evaluation of new fossil-fuel generation that may be needed while addressing once-through cooling concerns, aging power plant retirements, potential changes in the operation of existing power plants due to GHG emission regulations, and potential increased electrification of the transportation system that may affect the state's ability to meet higher renewable targets (*IEPR 2008 Update*, page 27) • Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006) directs the Energy Commission to assess the potential vulnerability of "large baseload generation facilities of 1,700 megawatts or greater" to a major disruption due to a seismic event or plant age-related issues (*IEPR 2008 Update*, page 65) **Distributed Generation** *Generation* • The Energy Commission believes that ultraclean and low-emission distributed generation technologies using non-renewable and renewable fuels should be reinstated [in the Self-Generation Incentive Program], especially those technologies used in CHP applications (*IEPR 2008 Update*, page 93) • The *2007 IEPR* noted the value of CHP systems in reducing carbon emissions because of their efficient use of fossil fuel through

		the capture of waste heat for other uses (such as power plant cooling) (*IEPR 2008 Update*, page 93) • The Energy Commission believes that distributed generation, including CHP, continues to show value for customers seeking solutions in a fluctuating energy climate (*IEPR 2008 Update*, page 94) • Currently, renewable fuels are eligible for the Self-Generation Incentive Program only if used with a fuel cell system. The CPUC should consider reinstituting formerly eligible engine and turbine technologies that operate on non-renewable fuels, landfill gas, digester gas from dairy waste or wastewater treatment processes, or biodiesel (*IEPR 2008 Update*, page 94) *Integration (Interconnection, Tariffs, Distribution)* • Assembly Bill 2778 (Lieber, Chapter 617, Statutes of 2006) required the Energy Commission, in consultation with the California Public Utilities Commission (CPUC) and the California Air Resources Board (ARB), to evaluate the CPUC's Self-Generation Incentive Program and the costs and benefits of expanding eligibility for the program to renewable and fossil fuel "ultraclean and low-emission distributed generation" (*IEPR 2008 Update*, page 85) • Assembly Bill 970 (Ducheny, Chapter 329, Statutes of 2000) directed the CPUC to adopt initiatives to reduce electricity demand, including providing incentives for distributed generation technologies (*IEPR 2008 Update*, page 85) • Furthermore, depending on the reading of the original objectives of the program, which call for "incentives for distributed generation to be paid for enhancing reliability" and "differential incentives for renewable or super clean distributed generation resources," then even generation technologies that do not run on a renewable fuel may enhance reliability and add significant value to the program participant, the ratepayer, and society as a whole (*IEPR 2008 Update*, page 93) • The CPUC has adopted some policies that permit the use of distributed generation, but economic barriers and the lack of incentives continue to hamper its development (*IEPR 2008 Update*, page 95) • The CPUC should develop tariff structures that make distributed generation and CHP projects "cost and revenue neutral" while granting credit to owners for providing system benefits, such as reduced congestion (*IEPR 2008 Update*, page 95) • Eliminate all non-bypassable charges for distributed generation and CHP regardless of interconnection voltage and standby reservation charges (*IEPR 2008 Update*, page 95) • Work collaboratively with the Energy Commission to develop a method that estimates the value of Self-Generation Incentive Program-funded projects, as well as distributed generation costs and benefits (*IEPR 2008 Update*, page 95) • Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007), requires utilities to include export power from new combined heat and power (CHP) projects of 20 MW and under in their long-term procurement plans (*IEPR 2008 Update*, page 107) • California's current energy efficiency programs should provide models and strategies that will support CHP development and goals (*IEPR 2008 Update*, page 107) **Water Use for Generation** • Since 2005, the Energy Commission has been working through the MOU Agreement process with the SWRCB, the RWQCBs, and the California Coastal Commission on a policy and regulatory approach to phase out once-through cooling for coastal power plants and increase the use of best available retrofit technologies such as large organism exclusion devices and modern screens at existing

		coastal power plants to minimize the marine environment impacts of using ocean water for once-through cooling of turbines (*IEPR 2008 Update*, page 119) • The Energy Commission believes that, in most cases, retiring and replacing or repowering the existing plants using once-through cooling with new facilities using other cooling options would be most beneficial to the state (*IEPR 2008 Update*, page 120) • Applications for Certification (AFC) for proposals for expanding or repowering existing coastal power plants using once-through cooling must now include recent studies to address the facility's current and expected impacts on marine species. The facility must have completed the studies within the last five years and include complete marine species impact information as required by federal Clean Water Act Section 316(b) regulations. Any proposals for new coastal generation facilities involving once-through cooling must also include these studies (*IEPR 2008 Update*, page 120) **Other** • Substantial economic, environmental, and regulatory barriers to developing new nuclear power plants in California mean that new nuclear plants cannot be relied on, at least in the near term, to meet California's AB 32 GHG emissions reduction goals for 2020 (*IEPR 2008 Update*, page 76)
IEPR 2005	Goals	**Natural Gas Power Plants** • By 2016, California's utilities will need to procure approximately 24,000 MW of peak resources to replace expiring contracts and retiring power plants and meet peak demand growth (*IEPR 2005*, page 52) • The Energy Commission recommends retirement of 66 aging power plants by 2012 (*2005 IEPR*, page 54) • The CPUC should require that IOUs procure enough capacity from long-term contracts to both meet their net short positions and allow for the orderly retirement or repowering of aging plants by 2012 (*2005 IEPR*, page 65) **Distributed Generation** • By the end of 2006, the CALIFORNIA ISO should modify its CHP tariffs in recognition of the unique operational requirements of CHP and allow CHP owners to sell their power to the state's electric grid at reasonable prices (*2005 IEPR*, page 78) • By the end of 2006, the CPUC should require IOUs to buy, through standardized contracts, all electricity from CHP plants in their service territories at their avoided cost, as defined by the CPUC in R.04-04-025 (*2005 IEPR*, page 79) • The CPUC should immediately develop a method to provide DG and CHP incentives to utilities and implement them by the end of 2006 (*2005 IEPR*, page 79) • The *Assessment of California CHP Market and Policy Options for Increased Penetration* determined the realistic goal of 5,400 MW of CHP by 2020 (*2005 IEPR*, page 79) • By the end of 2006, the Energy Commission and CPUC should collaboratively translate this goal into annual IOU procurement targets (*2005 IEPR*, page 79)
	Directives	**Natural Gas Power Plants** • In 2003, state policy makers identified an investment loading order as a transformational effort to curb demand and overcome the inertia that perpetuates the system's reliance on natural gas. The loading order calls for optimizing energy efficiency and demand response; meeting new generation needs first with renewable resources and distributed generation, then with clean fossil fuel generation; and improving the bulk transmission and distribution infrastructure (*2005 IEPR*, page 42)

		• Since November 2003 alone, the Energy Commission has permitted 11 power plants totaling 5,750 MW of capacity, primarily natural gas-fi red. However, California has 7,318 MW of approved power plant projects that have no current plans to begin construction because they lack the power purchase agreements needed to secure their financing (*2005 IEPR*, page 51) • The CPUC raised the possibility that utilities might need to either enter into new contracts or build new capacity to ensure adequate resources toward the end of this decade (*2005 IEPR*, page 61) • Since California faces both increasing electricity demand growth and an urgent need to modernize its generation fleet, it is critical that there are enough long-term commitments to bring new generation on line and repower existing aging power plants. This is necessary both to meet future reliability needs and ensure moderate prices (*2005 IEPR*, page 62) • Maintaining so many older plants on life support at low capacity factors has prevented construction of more efficient plants that would operate at higher capacities (*2005 IEPR*, page 63) • Virtually all of the state's aging power plants operate at high heat rate capacities that would typically not be dispatched enough in the open market to cover their fixed costs and justify their continued operation (*2005 IEPR*, page 63) • While it is undoubtedly true that operation of some of these aging plants is critical to meet local reliability, the state would be better off repowering the plants that are locationally critical to the state's electricity system (*2005 IEPR*, page 64) • The CALIFORNIA ISO awards cost-based contracts to plants deemed critical to local reliability. Many power plants supporting this local reliability are old, inefficient, and slated for replacement or retirement. The challenge for policy makers, the CALIFORNIA ISO, and utilities is to identify the best balance of transmission and generation to create sustainable local reliability (*2005 IEPR*, page 93) • Although Californians continue to use electricity more efficiently, total electricity demand is growing, requiring additional power plants to meet the state's needs. Since November 2003 alone, the state has permitted 11 power plants totaling 5,750 MW of capacity, primarily natural gas-fired (*2005 IEPR*, page 124) • Past forecasts projected California's demand for natural gas for power generation to increase more quickly than demand in other sectors. Now, however, the demand for gas in California's electricity sector is expected to grow at a relatively modest rate of 0.6 percent per year through 2016 as newly built power plants become operational and aggressive energy efficiency in electricity end uses and higher prices dampen demand (*2005 IEPR*, page 126) • Unfortunately, the conditions affecting natural gas supply adequacy are highly variable, including weather in the short-term and greater reliance in the western United States on gas-fired plants in the long-term (*2005 IEPR*, page 126) • The Energy Commission currently evaluates natural gas adequacy under average conditions and normal peak conditions. However, there is a need to evaluate potential responses to extreme conditions to avoid costly natural gas curtailments. The Energy Commission should therefore devote resources to secure the necessary data and increase its analytical ability to ensure that the natural gas infrastructure will continue to be adequate in the future under all conditions (*2005 IEPR*, page 126) • The primary source of greenhouse gas emissions is the burning of fossil fuels in motor vehicles, refineries, industrial facilities, and power plants (*2005 IEPR*, page 153) • In spite of its size, California ranks among the better states and countries when considering per capita emissions of greenhouse

		gases. This is the result of two primary factors: aggressive building and appliance standards put in place over the years by the Energy Commission that have limited power plant generation growth and the stringent air quality standards applied to power plants that have resulted in power plants burning cleaner natural gas rather than oil (*2005 IEPR*, page 153) • In its *2003 Energy Report,* the Energy Commission recommended required reporting of greenhouse gas emissions as a condition of state licensing of new electricity generating facilities (*2005 IEPR*, page 153) • Each IOU, municipal utility, and load-serving entity should develop an action plan to meet the Governor's greenhouse gas reduction goals, implementation of which should be monitored by the Energy Commission and the California Environmental Protection Agency (*2005 IEPR*, page 157) • California should seek credit for early actions in reducing greenhouse gas emissions in any future federal statutory or regulatory system and should take a leadership role in researching and developing low-carbon-emitting technologies (*2005 IEPR*, page 157) • Generation from new natural gas-fired power plants in the CA/Mexico border region will predominantly meet this growing demand for electricity, though attention is increasingly focused on developing renewable energy resources (*2005 IEPR*, page 163) • Natural gas demand in SDG&E's service territory is forecast to grow 2.5 percent annually. The primary driver for this gas demand in the near term is the natural gas needed to fuel new power plants (*2005 IEPR*, page 164) **Carbon Capture and Sequestration** • For regions like the West where lower-rank fuels predominate, pulverized coal with "ultra-supercritical" main steam conditions (USC PC) and circulating fluidized-bed combustion plants with supercritical main steam conditions (SC CFBC) may be the most cost-effective advanced coal combustion options, but they lack the same opportunity for CO2 capture offered by IGCC (*2005 IEPR* page 82) • California's efforts should focus on longer-term research and development on advanced concepts for IGCC, USC PC, and SC CFBC plants—including integration of CO2 capture systems—for plants coming on line after 2015-2020 (*2005 IEPR*, page 82) • In close coordination with the US DOE, the Energy Commission is supporting a growing research program aimed at developing and validating options for sequestering CO2 away from the atmosphere.(*2005 IEPR*, page 82) • Findings to date suggest that the sandstone formations filled with saltwater deep beneath California's Central Valley could collectively store hundreds of years of CO2 emissions at the current rate of emission by the state's power plants (*2005 IEPR*, page 83) • In the case of coal-fired generation, the capacity to capture and store carbon dioxide safely and inexpensively is necessary to meet the standards (*2005 IEPR*, page 83) • Since California will continue to rely on coal for some portion of its electricity, the state should take a leadership role in developing technologies that capture and store CO2 (*2005 IEPR*, page 158) **Distributed Generation** *Generation* • An important alternative to building large new power plants is distributed generation, which is electricity produced on site or close to load centers that is also connected to a utility's distribution system. The most efficient and cost-effective form of distributed generation is cogeneration or combined heat and power. By

		recycling waste heat, these systems are much more efficient than systems that separately serve thermal and electric loads. They are also considerably more efficient than almost all conventional gas-fired power plants (*2005 IEPR*, Page 3)
		• Anaerobic digesters installed at or near wastewater treatment facilities, dairies, or food processing facilities can also produce biogas, which can be used to either power on-site generation or be sold to the grid (*2005 IEPR*, Page 5)
		• Another way to increase natural gas efficiency is to increase the role of combined heat and power facilities as a way to meet California's rising electricity supply needs (*2005 IEPR*, Page 7)
		• The state should work with the petroleum industry and other agencies to identify opportunities for additional cogeneration at refineries (*2005 IEPR*, Page 42)
		• The Energy Commission also recommends additional emphasis on distributed generation and combined heat and power resources (*2005 IEPR*, page 54)
		• Governor Schwarzenegger has emphasized that the state should encourage distributed generation and combined heat and power since "it can occur at load centers, reducing the need for further infrastructure additions" (*2005 IEPR*, page 69)
		• DG is a key element of California's loading order strategy and will help meet the state's energy efficiency and renewable energy goals (*2005 IEPR*, page 76)
		• CHP is of such unique value in meeting loading order efficiency and new generation objectives that CHP deserves its own place in the loading order (*2005 IEPR*, page 78)
		• Initial research from the Energy Commission's Public Interest Energy Research program shows that DG and CHP can provide quantifiable benefits to utility systems (*2005 IEPR*, page 80)
		• CHP effectively reduces greenhouse gas emissions (IERP 2005, Page 80)
		• To increase natural gas efficiency in the future, combined heat and power facilities should play a much larger role in meeting California's electricity supply needs (*2005 IEPR*, page 130)
		Integration (Interconnection, Tariffs, Distribution)
		• The Energy Commission strongly supports the following combined heat and power recommendations:
		  • The CPUC and the Energy Commission should establish annual utility procurement targets for combined heat and power facilities by the end of 2006;
		  • The CPUC should require investor-owned utilities to purchase electricity from combined heat and power facilities at prevailing wholesale prices;
		  • The CPUC should explore regulatory incentives that reward utilities for promoting customer and utility-owned combined heat and power projects;
		  • The CPUC should require that investor-owned utilities provide California Independent System Operator (CALIFORNIA ISO) scheduling services for these facilities and be compensated for doing so (*2005 IEPR*, Page 3)
		• The petroleum refining industry is one of the largest users of cogeneration in the United States, California refineries have an installed cogeneration capacity of about 1,400 MW and have the potential to increase their use of cogeneration technologies. Cogeneration at refineries improves the efficiency of natural gas use and helps insulate the facilities from electric grid problems.(*2005 IEPR*, Page 42)
		• To bring enough new generation on line to meet future demand, the state must vigorously pursue preferred resources: renewables, distributed generation, and lastly, conventional generation.(*2005 IEPR*, page 69)

		• Cogeneration, or combined heat and power (CHP), is the most efficient and cost-effective form of DG, providing numerous benefits to California including reduced energy costs, more efficient fuel use, fewer environmental impacts, improved reliability and power quality, locations near load centers, and support of utility transmission and distribution systems (*2005 IEPR*, page 76) • California should particularly encourage CHP at the state's petroleum refineries to make them less vulnerable to power outages (*2005 IEPR*, page 76) • The state also needs to improve access to wholesale energy markets and streamline the utilities' long-term contract processes so that CHP owners can easily and efficiently sell their excess electricity to their local utility (*2005 IEPR*, page 78) • For California to practically establish its societal preference for DG and CHP, IOUs should be compensated for their revenue shortfalls at least to the point of making them cost neutral *2005 IEPR*, page 79) • California should explore regulatory incentives to reward IOUs for promoting public– and utility-owned CHP and DG projects (*2005 IEPR*, page 79) **Water Use for Generation** • The Energy Commission recommends expediting and reducing the cost of utility interconnection, eliminating economic penalties including standby charges, removing size limitations for net metering, and allowing water and wastewater utilities to self generate and wheel power within their own systems (*2005 IEPR*, Page 6) • Power plants use a significant volume of water, primarily for cooling. This water demand by power plants can have a significant effect on local water supplies. The *2003 Energy Report* adopted a policy requiring new power plants to use degraded or recycled water or air-cooled systems to reduce the amount of fresh water used in power plant cooling systems (*2005 IEPR*, page 139) • California has a number of power plants along its bays and coastline that use once-through cooling. The state has the opportunity to more comprehensively study the impacts of once-through cooling on the marine environment as part of the Governor's California Ocean Protection Council efforts, as well as the State and Regional Water Quality Control Boards' review of impacts under Section 316(b) of the federal *Clean Water Act* (*2005 IEPR*, page 139) • Recycled water can substitute for fresh water in power plant cooling and other industrial processes, landscape irrigation, and to replenish groundwater aquifers (*2005 IEPR*, page 140) • Recent studies indicate that the use of seawater for once-through cooling can contribute to the decline of fisheries and the degradation of estuaries and bay and coastal waters (*2005 IEPR*, page 147) • In September 2004, the U.S. Environmental Protection Agency (U.S. EPA) released a new federal rule under Section 316(b) of the federal *Clean Water Act* to reduce the environmental impacts from existing power plants that use once-through cooling (*2005 IEPR*, page 148) • The Energy Commission's PIER program should continue to collaborate with the State Water Resources Control Board, the Regional Water Quality Control Boards, the Department of Fish and Game, and other stakeholders to develop sampling and other analytical protocols and guidelines that will provide clear, consistent approaches for assessing the ecological effects of once-through cooling (*2005 IEPR*, page 148) • The Energy Commission should update its current memoranda-of-understanding agreement with the State Water Resources Control Board, the Regional Water Quality Control Boards, and the

		California Coastal Commission to develop a consistent regulatory approach for the use of once-through cooling in power plants, including the use of best-available retrofit technologies to minimize impacts on the marine environment. The Energy Commission should also actively participate in the 316(b) reviews of coastal power plant once-through cooling impacts (*2005 IEPR*, page 148) • The Energy Commission should update current data adequacy regulations with respect to once-through cooling at the state's coastal power plants. Existing data adequacy regulations for power plant licensing applications do not provide sufficient guidance regarding the type and extent of data needed to complete an analysis of power plants proposing to use once-through cooling technologies (*2005 IEPR*, page 148) **Other** • California must continue to be highly aware of the environmental impacts of its energy policies. As the world's seventeenth largest emitter of greenhouse gases, California must incorporate its efforts to reduce greenhouse gases into its energy policies (*2005 IEPR*, Page 10) • The CPUC now requires that investor-owned utilities use a carbon dioxide adder of an initial $8 per ton in their long-term procurement plans, encouraging them to invest in lower-emitting resources. In addition, the CPUC unanimously adopted a resolution directing its staff to develop an investor-owned utility greenhouse gas performance standard "that is no higher than the greenhouse gas emission levels of a combined-cycle natural gas turbine" for all procurement contracts longer than three years (*2005 IEPR*, Page 10) • The Energy Action Plan commits that the agencies will "… ensure that energy supplies serving California, from any source, are consistent with the Governor's climate change goals." The Energy Commission endorses the CPUC's setting a greenhouse gas performance standard for investor-owned utilities and agrees that an offset policy must await a formal greenhouse gas regulatory system and must include a reliable and enforceable system of tracking emission reductions. The Energy Commission looks forward to working with the CPUC to implement a greenhouse gas performance standard as part of the 2006 procurement proceeding (*2005 IEPR*, Page 10) • The Energy Commission recommends the following: A greenhouse gas performance standard for utility procurement should be set no higher than emission levels from new combined-cycle natural gas turbines (*2005 IEPR*, Page 11)
2003 IEPR	Directives	**Natural Gas Power Plants** • The state can further reduce natural gas consumption for electric generation by taking steps to retire older, less efficient natural gas-fired power plants and replace or repower these facilities with new, more efficient plants (*2003 IEPR*, page 6) • Since 2001, more than 9,500 MW of generating capacity has come on-line, most new, efficient natural gas-fired generators. These additions constitute the largest expansion of the power plant fleet in California history.(*2003 IEPR*, page 7) • Under average weather conditions, the Energy Commission believes that California should have adequate supplies of electricity through 2009 (*2003 IEPR*, page 8) • The Energy Commission has projected that 4,630 MW of existing capacity will likely retire through 2006 (*2003 IEPR*, page 8) • California …needs to examine the efficiency of its existing fleet of power plants . Concerns have been raised that the aging fleet of power plants still operating in the state are more polluting and less efficient than modern power plants (*2003 IEPR*, page 17)

		• Electricity generators could retire older, less-efficient natural gas-fired power plants and replace or repower them with new, more efficient ones. Unfortunately, many of these plants are presently used to maintain system reliability (*2003 IEPR*, page 24) • Before California can retire or replace existing power plants, it must examine the contractual arrangements that dictate their use (*2003 IEPR*, page 24) • To replace the aging power plants now used for reliability purposes, their cleaner, more efficient upgrades or replacements must receive similar financial incentives that recognize their benefits to local reliability and California's overall grid system (*2003 IEPR*, page 24) • Despite its support of renewable energy, California depends increasingly on natural gas generation, and natural gas-fired generation in California is expected to increase from 36 percent in 2004 to 43 percent in 2013 (*2003 IEPR*, page 26) • Require reporting of greenhouse gas emissions as a condition of state licensing of new electric generating facilities (*2003 IEPR*, page 42) **Distributed Generation** *Generation* • Consumers and businesses should be able to supply their own generation through the deployment of distributed generation and cogeneration (*2003 IEPR*, Page 5) • Distributed generation, including cogeneration and self-generation, has tremendous potential to help meet California's growing energy needs as an additional generation source and an essential element of customer choice (*2003 IEPR*, page 15) • Its use offers potential benefits that extend to customers, utilities, and the system as a whole and can be used strategically to meet the policy objectives of the RPS and reduce greenhouse gases (*2003 IEPR*, page 15) • Cogeneration offers another low-cost, low-emission option for the efficient use of natural gas. By creating both electric and thermal energy, cogeneration plants can achieve heat rates that "match or exceed the heat rates of new gas-fired combined- cycle power plants"(*2003 IEPR*, page 24) • Cogeneration is a major element in the state's energy system, contributing more than 6,300 MW (*2003 IEPR*, page 24) *Integration (Interconnection, Tariffs, Distribution)* • In response to industry concerns, the CPUC also exempted 3,000 MW of distributed generation over the next 10 years from the Cost Responsibility Surcharge or "exit fee" imposed on customers who leave the grid (*2003 IEPR*, page 15) • Utilities are currently required to consider distributed generation as part of its distribution system planning process (*2003 IEPR*, page 15) • Ultimately, the long-term successful deployment of distributed generation will require focused policy direction. Much of the focus should be targeted at increasing consumer awareness about the benefits of using distributed generation, providing financial incentives to offset the cost of installation, and funding research to advance technology so that incentives are eventually no longer needed (*2003 IEPR*, page 16) • Create a transparent electricity distribution system planning process that addresses the benefits of distributed generation (*2003 IEPR*, page 16) **Water Use for Generation** • Since 1996, an increasing number of new power plants have been sited in areas with limited fresh water supplies. As a result, the use of fresh water for power plant cooling is increasing. Although

		water use for power plant cooling is relatively small on a statewide basis, it can cause significant impacts to local water supplies (*2003 IEPR*, page 39) • Degraded surface and groundwater can be reused for power plant cooling. When sufficient quantities are available, reclaimed water is a commercially viable cooling medium (*2003 IEPR*, page 39) • Alternative cooling options, such as dry cooling, are also available and commercially viable, and can reduce or eliminate the need for fresh water (*2003 IEPR*, page 39) • Continued use of once-through cooling at existing power plants may impact aquatic resources in the coastal zone, bays, and estuaries (*2003 IEPR*, page 40) • While power plants using once-through cooling have not been proposed for new California coastal sites in the last two decades, proposals to repower existing generation units at these sites have not switched to dry cooling or recycled water (*2003 IEPR*, page 40) • Because power plants have the potential to use substantial amounts of water for evaporative cooling, the Energy Commission has the responsibility to apply state water policy to minimize the use of fresh water, promote alternative cooling technologies, and minimize or avoid degradation of the quality of the state's water resources (*2003 IEPR*, page 40) • With respect to using fresh water, Resolution 75-58 articulates an underlying policy "to protect beneficial uses of the state's water resources and to keep the consumptive use of freshwater for power plant cooling to that minimally essential for the welfare of the citizens of the state" (*2003 IEPR*, page 40) • Specifically, the State Water Resources Control Board states that it "encourages … power generating utilities and agencies to study the feasibility of using wastewater for power plant cooling" and "encourages the use of wastewater for power plant cooling where it is appropriate" (*2003 IEPR*, page 40) • The Board also lists specific "discharge prohibitions" to limit the discharge of blowdown and waste waters from cooling facilities so as to "maintain existing water quality and aquatic environment of the state's water resources" (*2003 IEPR*, page 40) • Consistent with the Board policy and the Warren-Alquist Act, the Energy Commission will approve the use of fresh water for cooling purposes by power plants which it licenses only where alternative water supply sources and alternative cooling technologies are shown to be "environmentally undesirable" or "economically unsound" (*2003 IEPR*, page 41) • Additionally, as a way to reduce the use of fresh water and to avoid discharges in keeping with the Board's policy, the Energy Commission will require zero-liquid discharge technologies unless such technologies are shown to be "environmentally undesirable" or "economically unsound" (*2003 IEPR*, page 41) **Other** • The Energy Commission also believes that targeted research, development, and commercialization is a necessary means of introducing new, more efficient, and cleaner technologies into the market (*2003 IEPR*, Page vii)
EAP I, II and 2008 Update	Goals	**Natural Gas Power Plants** • Add new generation resources to meet anticipated demand growth, modernize old, inefficient and dirty plants and achieve and maintain reserve levels in the 15 percent-18 percent range. Current estimates show a statewide need for 1500 -2000 MW per year (EAP I, page 6) • In January and October 2004, the CPUC adopted resource adequacy requirements for the IOUs and ESPs to secure a 15-17

		percent planning reserve margin by June 2006 (EAP II, appendix page 4) **Other** • Identify western state policies and strategies to achieve production of 30,000 MW of clean energy across the west by 2015, consistent with the Western Governors' Association Clean and Diversified Energy Advisory Committee and West Coast Climate Initiative goals (EAP II, page 13) • The Action Plan envisions a "loading order" of energy resources that will guide decisions made by the agencies jointly and singly. • First the agencies want to optimize all strategies for increasing conservation and energy efficiency to minimize increases in electricity and natural gas demand; • Second, recognizing that new generation is both necessary and desirable, the agencies would like to see these needs met first by renewable energy resources and distributed generation; • Third, because the preferred resources require both sufficient investment and adequate time to "get to scale," the agencies also will support additional clean, fossil fuel, large scale power generation • Simultaneously, the agencies intend to improve the bulk electricity transmission grid and distribution facility infrastructure to support growing demand centers and the interconnection of new generation (EAP I, page 4)
	Directives	**Natural Gas Power Plants** • This approach [the Energy Action Plan initiatives] will be ever mindful of the need to keep energy rates affordable, and is sensitive to the implications of energy policy on global climate change and the environment generally (EAP 1, page 1) • The goal of the Energy Action Plan is to: Ensure that adequate, reliable, and reasonably-priced electrical power and natural gas supplies, including prudent reserves, are achieved and provided through policies, strategies, and actions that are cost-effective and environmentally sound for California's consumers and taxpayers.(EAP I, page 2) • Ensure reliable, affordable, and high quality power supply for all who need it in all regions of the state by building sufficient new generation (EAP I, page 2) • License and, where necessary, fund construction of new energy facilities that are consistent with the reliability, economic, public health, and environmental needs of the state (EAP I, page 2) • Over the last decade, between 29 percent and 42 percent of California's in-state generation used natural gas (EAP I, page 4) • Electricity generation's dependence on relatively clean-burning natural gas now means that California's annual natural gas use by power plants is expected to increase (EAP I, page 4) • Finance a few critical power plants that the agencies conclude are necessary and would not otherwise be built . An estimated 300 MW of peaking capacity located in critical areas is needed to provide local reliability, help achieve adequate reserves, and reduce congestion and the need for new transmission lines (EAP I, page 6) • Work with the California Independent System Operator (CAISO) to implement generator maintenance standards and an oversight process to support coordinated availability of generation (EAP I, page 6) • Ensure that all load serving entities meet the state's adopted reserve and resource adequacy requirements of a 15-17 percent planning reserve no later than June 2006, through a reasonable mix of short-, medium- and long-term resource commitments (EAP II, page 7) • After incorporating higher loading order resources, encourage the

		development of cost-effective, highly-efficient, and environmentally-sound supply resources to provide reliability and consistency with the State's energy priorities (EAP II, page 7) • Establish appropriate incentives for the development and operation of new generation to replace the least efficient and least environmentally sound of California's aging power plants (EAP II, page 7) • Manage California's aging electricity infrastructure to coordinate maintenance and outages and to provide orderly retirements (EAP II, page 7) • Because natural gas is becoming more expensive, and because much of electricity demand growth is expected to be met by increases in natural gas-fired generation, reducing consumption of electricity and diversifying electricity generation resources are significant elements of plans to reduce natural gas demand and lower consumers' bills (EAP II, page 10) • We must also encourage RD&D for conventional generation sources and transportation fuels to reduce emissions, increase efficiency, and mitigate environmental impacts (EAP II, page 11) • Require reporting of GHG emissions as a condition of state licensing of new electric generating facilities (EAP II, page 13) • Even with energy efficiency, demand response, and renewable resources, investments in conventional power plants and transmission and distribution infrastructure will still be needed (EAP 2008 Update, page 15) **Distributed Generation** *Generation* • Promote customer and utility owned distributed generation (EAP I, page 2) • Distributed generation is an important local resource that can enhance reliability and provide high quality power, without compromising environmental quality (EAP I, page 7) • The state is promoting and encouraging clean and renewable customer and utility owned distributed generation as a key component of its energy system (EAP I, page 7) • Develop standards so that renewable distributed generation may participate in the Renewable Portfolio Standard program (EAP I, page 8) • Provide for the continued operation of cost-effective and environmentally – sound existing generation needed to meet current reliability needs, including combined heat and power generation (EAP II, page 7) • In addition, new combined heat and power applications could play a large part in avoiding future greenhouse gas emissions due to the combined efficiency of the heat and power portions of the project (EAP 2008 update, page 15) • Promote clean, small generation resources located at load centers (EAP I, page 8) *Integration (Interconnection, Tariffs, Distribution)* • With proper inducements distributed generation will become economic (EAP I, page 8) • Determine whether and how to hold distributed generation customers responsible for costs associated with Department of Water Resources power purchases (EAP I, page 8) • Determine system benefits of distributed generation and related costs (EAP I, page 8) • Standardize definitions of eligible distributed generation technologies across agencies to better leverage programs and activities that encourage distributed generation (EAP I, page 8) • Collaborate with the Air Resources Board, Cal-EPA and representatives of local air quality districts to achieve better

		integration of energy and air quality policies and regulations affecting distributed generation (EAP I, page 8) • The agencies will work together to further develop distributed generation policies, target research and development, track the market adoption of distributed generation technologies, identify cumulative energy system impacts and examine issues associated with new technologies and their use (EAP I, page 8) • Develop tariffs and remove barriers to encourage the development of environmentally-sound combined heat and power resources and distributed generation projects (EAP II, page 8) • The CPUC adopted favorable rate policies for DG, including exemptions from stand-by and departing load charges, and expanded net metering (EAP II, appendix page 6) • Other forms of distributed generation, even if not renewable, can also have benefits over large scale power generation that suffers from transmission and distribution line losses (EAP 2008 update, page 15) • Distributed generation can also help support grid reliability (EAP 2008 update, page 16) **Carbon Capture and Sequestration** • Evaluate the potential for California's access to clean coal energy resources and recommend a California clean coal policy in the 2005 IEPR (EAP II, page 7) • Support clean coal technology research and development, and continue to develop methods for capturing and storing significant amounts of CO2, either as an integral part of the energy conversion process or in pairing with external CO2 sequestration (EAP II, page 12) • We hope that advances can be made over the next few years in the utilization of carbon capture and sequestration techniques, to ensure that even when a power plant emits greenhouse gases, they can be captured permanently without being allowed to escape into the atmosphere (EAP 2008 update, page 16) • We support the development of carbon capture and sequestration technologies through additional policies and demonstration efforts, as well as continued research and development (EAP 2008 update, page 16) • To meet our long-term greenhouse gas goals, we will likely need the development of…clean fossil generation (including carbon capture and sequestration) (EAP 2008 update, page 21) **Water Use for Generation** • Encourage the development of cost-effective dry-cooling technologies and reduce once-through cooling practices to minimize the impact of new generation on California's water resources (EAP II, page 12) **Other** • To protect the public's health and safety and ensure our quality of life, the agencies support the most cost-effective and environmentally sound strategies, including consideration of global climate change (EAP I, page 3) • The agencies also will work to ensure that low-income populations do not experience disproportionate adverse impacts from the development of new energy systems (EAP I, page 3) • California's continued success in supplying an efficient and diverse mix of resources to meet our energy needs is dependent upon technological innovations (EAP II, page 11)
SB 1250	Directives	• It is in the best interests of the people of this state that the quality of life of its citizens be improved by providing environmentally sound, safe, reliable, and affordable energy services and products (SB 1250, page 3) • To improve the quality of life of this state's citizens, it is proper

and appropriate for the state to undertake public interest energy research, development, and demonstration projects that are not adequately provided for by competitive and regulated energy markets (SB 1250, page 3)

- Public interest energy research, demonstration, and development projects should advance energy science or technologies of value to California citizens and should be consistent with the policies of this chapter (SB 1250, page 3)
- The general goal of the [Public Interest Research, Development, and Demonstration Program] is to develop, and help bring to market, energy technologies that provide increased environmental benefits, greater system reliability, and lower system costs, and that provide:
  - Advanced electricity generation technologies that exceed applicable standards to increase reductions in greenhouse gas emissions from electricity generation, and that benefit electric utility customers
  - Advanced electricity technologies that reduce or eliminate consumption of water or other finite resources, increase use of renewable energy resources, or improve transmission or distribution of electricity generated from renewable energy resources (SB 1250, pages 3-4)
- To achieve these goals…the commission shall adopt a portfolio approach for the program that does all of the following:
  - Effectively balances the risks, benefits, and time horizons for various activities and investments that will provide tangible energy or environmental benefits for California electricity customers
  - Emphasizes innovative energy supply and end use technologies, focusing on their reliability, affordability, and environmental attributes.
  - Includes projects that have the potential to enhance transmission and distribution capabilities.
  - Includes projects that have the potential to enhance the reliability, peaking power, and storage capabilities of renewable energy.
  - Demonstrates a balance of benefits to all sectors that contribute to the funding under Section 399.8 of the Public Utilities Code.
  - Addresses key technical and scientific barriers.
  - Demonstrates a balance between short-term, mid-term, and long-term potential.
  - Ensures that prior, current, and future research not be unnecessarily duplicated.
  - Provides for the future market utilization of projects funded through the program.
  - Ensures an open project selection process and encourages the awarding of research funding for a diverse type of research as well as a diverse award recipient base and equally considers research proposals from the public and private sectors.
  - Coordinates with other related research programs (SB 1250, page 4)
- In order to ensure that prudent investments in research, development, and demonstration of energy efficient technologies continue to produce substantial economic, environmental, public health, and reliability benefits, it is the policy of the state and the intent of the Legislature that funds made available, upon appropriation, for energy related public interest research, development, and demonstration programs shall be used to advance science or technology that is not adequately provided by competitive and regulated markets (SB 1250, page 8)
- Notwithstanding any other provision of law, money collected for

		public interest research, development, and demonstration pursuant to Section 399.8 of the Public Utilities Code shall be transferred to the Public Interest Research, Development, and Demonstration Fund. Money collected between January 1, 2007, and January 1, 2012, shall be used for the purposes specified in this chapter (SB 1250, page 8)
		• The commission's long-term goal shall be a fully competitive and self-sustaining California renewable energy supply (SB 1250, page 8)
		• The program objective shall be to increase, in the near term, the quantity of California's electricity generated by in-state renewable energy resources, while protecting system reliability, fostering resource diversity, and obtaining the greatest environmental benefits for California residents (SB 1250, page 8)
		• The Legislature finds and declares that safe, reliable electric service is of utmost importance to the citizens of this state, and its economy (SB 1250, page 16)
		• The Legislature further finds and declares that in order to ensure that the citizens of this state continue to receive safe, reliable, affordable, and environmentally sustainable electric service, it is essential that prudent investments continue to be made in all of the following areas
		  • To protect the integrity of the electric distribution grid
		  • To ensure an adequately sized and trained utility workforce
		  • To ensure cost-effective energy efficiency improvements
		  • To achieve a sustainable supply of renewable energy
		  • To advance public interest research, development and demonstration programs not adequately provided by competitive and regulated markets (SB 1250, page 16)

SB 1368	Directives	• New long-term financial commitments to zero- or low-carbon generating resources should be encouraged (SB 1368, page 4) • The establishment of a policy to reduce emissions of greenhouse gases, including an emissions performance standard for all procurement of electricity by load-serving entities, is a logical and necessary step to meet the goals of the Energy Action Plan II and the Governor's goals for reduction of emissions of greenhouse gases (SB 1368, page 4) • As the largest electricity consumer in the region, California has an obligation to provide clear guidance on performance standards for procurement of electricity by load-serving entities (SB 1368, page 4) • No load-serving entity or local publicly owned electric utility may enter into a long-term financial commitment unless any baseload generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission (SB 1368, page 6) • On or before February 1, 2007, the commission, through a rulemaking proceeding, and in consultation with the Energy Commission and the State Air Resources Board, shall establish a greenhouse gases emission performance standard for all baseload generation of load-serving entities, at a rate of emissions of greenhouse gases that is no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas base-load generation (SB 1368, page 7) • All combined-cycle natural gas power plants that are in operation, or that have an Energy Commission final permit decision to operate as of June 30, 2007, shall be deemed to be in compliance with the greenhouse gases emission performance standard (SB 1368, page 7)
AB 32	Goals	• On or before January 1, 2008, the state board shall adopt regulations to require the reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance

		with this program. The regulations shall do all of the following: • Require the monitoring and annual reporting of greenhouse gas emissions from greenhouse gas emission sources beginning with the sources or categories of sources that contribute the most to statewide emissions • Account for greenhouse gas emissions from all electricity consumed in the state, including transmission and distribution line losses from electricity generated within the state or imported from outside the state. This requirement applies to all retail sellers of electricity, including load-serving entities as defined in subdivision (j) of Section 380 of the Public Utilities Code and local publicly owned electric utilities as defined in Section 9604 of the Public Utilities Code • Ensure rigorous and consistent accounting of emissions, and provide reporting tools and formats to ensure collection of necessary data • Ensure that greenhouse gas emission sources maintain comprehensive records of all reported greenhouse gas emissions (AB 32, page 5) • By January 1, 2008, the state board shall… determine what the statewide greenhouse gas emissions level was in 1990, and approve in a public hearing, a statewide greenhouse gas emissions limit that is equivalent to that level, to be achieved by 2020 (AB 32, page 6) • It is the intent of the Legislature that the statewide greenhouse gas emissions limit continue in existence and be used to maintain and continue reductions in emissions of greenhouse gases beyond 2020 (AB 32, page 6)
	Directives	• Global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California (AB 32, page 2) • The state board shall adopt rules and regulations in an open public process to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions from sources or categories of sources, subject to the criteria and schedules set forth in this part (AB 32, page 6) • The state board shall consult with all state agencies with jurisdiction over sources of greenhouse gases, including the Public Utilities Commission and the State Energy Resources Conservation and Development Commission, on all elements of its plan that pertain to energy related matters including, but not limited to, electrical generation, load based-standards or requirements, the provision of reliable and affordable electrical service, petroleum refining, and statewide fuel supplies to ensure the greenhouse gas emissions reduction activities to be adopted and implemented by the state board are complementary, nonduplicative, and can be implemented in an efficient and cost-effective manner (AB 32, page 7) • In developing its plan, the state board shall identify opportunities for emission reductions measures from all verifiable and enforceable voluntary actions, including, but not limited to, carbon sequestration projects and best management practices (AB 32, page 7) • Nothing in this division shall preclude, prohibit, or restrict the construction of any new facility or the expansion of an existing facility subject to regulation under this division, if all applicable requirements are met and the facility is in compliance with regulations adopted pursuant to this division (AB 32, page 12)
AB 1613	Directives	• A local publicly owned electric utility serving retail end-use customers shall establish a program that does both of the following: • Allows retail end-use customers to utilize combined heat and power systems that reduce emissions of greenhouse gases by achieving improved efficiencies utilizing heat that would otherwise be wasted in separate energy applications

		• Provides a market for the purchase of excess electricity generated by a combined heat and power system, at a just and reasonable rate, to be determined by the governing body of the utility (AB 1613, page 6)
		• The commission shall ensure that an electrical corporation utilizes long-term planning and a reliability assessment for upgrades to its transmission and distribution systems and that any upgrades are not inconsistent with promoting combined heat and power systems that are cost effective, technologically feasible, and environmentally beneficial, particularly as those combined heat and power systems reduce emissions of greenhouse gases (AB 1613, page 6)
		• The Energy Commission shall, by January 1, 2010, adopt guidelines that combined heat and power systems subject to this chapter shall meet, and shall accomplish all of the following:
		  • Reduce waste energy
		  • Be sized to meet the eligible customer-generator's thermal load
		  • Operate continuously in a manner that meets the expected thermal load and optimizes the efficient use of waste heat
		  • Are cost effective, technologically feasible, and environmentally beneficial (AB 1613, page 7)
		• The State Air Resources Board shall report to the Governor and the Legislature by December 31, 2011, on the reduction in emissions of greenhouse gases resulting from the increase of new electrical generation that utilizes excess waste heat through combined heat and power systems and recommend policies that further the goals of this article (AB 1613, page 8)

Governor's Executive OrdersS-3-05 and S-14-08	Goals	• The following greenhouse gas emission reduction targets are hereby established for California: by 2010, reduce GHG emissions to 2000 levels; by 2020, reduce GHG emissions to 1990 levels; by 2050, reduce GHG emissions to 80 percent below 1990 levels (S-3-05) • California has previously led the nation with an aggressive Renewable Portfolio Standard (RPS), requiring California's retail sellers of electricity to serve 20 percent of their load with renewable energy by 2010 (S-14-08) • That the Secretary [of the California Environmental Protection Agency] shall report to the Governor and the State Legislature by January 2006 and biannually thereafter on progress made toward meeting the greenhouse gas emission targets established herein (S-3-05) • In 2003, the Governor called for an acceleration of the RPS, urging that 20 percent of California's electricity come from renewable sources by 2010 rather than 2017, seven years earlier than previously required, and this accelerated standard became law in September 2006, when the Governor signed SB 107 (S-14-08) • The following Renewable Portfolio Standard target is hereby established for California: All retail sellers of electricity shall serve 33 percent of their load with renewable energy by 2020 (S-14-08) • By January 1, 2010, the CEC shall provide an estimate of total retail electricity sales in California in 2020 by utility and shall update this number every two years through the IEPR (S-14-08)
	Directives	• California is particularly vulnerable to the impacts of climate change (S-3-05) • Mitigation efforts will be necessary to reduce greenhouse gas emissions and adaptation efforts will be necessary to prepare Californians for the consequences of global warming (S-3-05) • That the Secretary shall also report to the Governor and the State Legislature by January 2006 and biannually thereafter on the impacts to California of global warming, including impacts to water

		• supply, public health, agriculture, the coastline, and forestry, and shall prepare and report on mitigation and adaptation plans to combat these impacts (S-3-05) • Pursuant to the MOU, DFG and CEC shall immediately create a "one-stop" process for permitting renewable energy generation power plants (S-14-08)
Governor's Ten Point Electricity Plan	Goal	• Resource Adequacy – Minimum 15 percent reserve margins for all suppliers of electricity, by 2006 (Ten Point Plan)
	Directives	• The Governor's electricity plan is designed to ensure an adequate, stable supply of electricity at reasonable prices. The plan encourages the use of emerging technologies to preserve and protect California's environment and promote economic growth (Ten Point Plan) • Research and Development – Invest in emerging technologies that improve the efficiency, effectiveness and environmental impact of energy supplies and infrastructure (Ten Point Plan)
Governor's Response to *2003 IEPR*	Directives	**Natural Gas Power Plants** • California state government needs to make certain that new electricity generation resources are developed, efficiency and demand response programs are augmented and electric transmission system infrastructure is expanded (2003 IEPR Response Letter, page 2) • These steps are necessary to meet the growing demand for electricity and to replace older power plants in California (2003 IEPR Response Letter, page 2) • The CPUC has developed detailed resource adequacy rules for the investor owned utilities…including minimum planning reserve margins of 15 percent, acquired sufficiently in advance (2003 IEPR Response Letter, page 2) • Although whether to shut down a power plant is a business decision, it may be cost-beneficial for the State to encourage some power plants to more slowly phase out of operations, especially if supply-demand balances warrant (2003 IEPR Response, page 2) **Carbon Capture and Sequestration** • I ask the Energy Commission to work with the California EPA and other agencies to evaluate the potential for California's access to such clean coal energy resources and report its initial findings with the goal of recommending a California clean coal policy in the 2005 Energy Report (2003 IEPR Response, page 5) • I support continued clean coal technology research and development towards zero emission operation so that we can economically achieve reduced emissions of pollutants (2003 IEPR Response, page 5) • Develop methods for capturing and storing significant amounts of CO2, either as an integral part of the energy conversion process or in pairing with external CO2 sequestration (2003 IEPR Response, page 5) • Given the diversity of regional electricity markets and the wide variation in regional coal properties, effective deployment of advanced coal power systems may entail the adoption of many different technologies, such as Integrated Gasification Combined Cycle (IGCC) and Supercritical Circulating Fluidized-Bed Combustion (SC CGBC), as well as technologies yet to be developed (2003 IEPR Response, page 5) **Distributed Generation** • An important benefit of clean distributed generation for electricity systems is that it can occur right at load centers, reducing the need for further infrastructure additions (2003 IEPR Response, page 6) • The CPUC should develop tariffs that encourage the installation

<table>
<tr><td></td><td></td><td>of distributed generation and cogeneration systems (2003 IEPR Response, page 6)
Other
• The goals of our energy policy should be to ensure:
  • Adequate and reliable energy supplies when and where needed
  • Affordable energy to homes and businesses
  • Advanced energy technologies that protect and improve economic and environmental conditions (2003 IEPR Response Letter, page 1)
• Energy research and development today prepare the way for a better energy future by bridging the gap between the laboratory and the marketplace (2003 IEPR Response Letter, page 6)
• State funded research and development and demonstration projects should focus on emerging technologies that improve the efficiency and effectiveness of energy supplies, uses and infrastructure while mitigating any environmental impacts (2003 IEPR Response Letter, page 6)
• The State must partner with private industry and coordinate with the federal Department of Energy and national laboratories to identify steps which best achieve these principles (2003 IEPR Response Letter, page 6)</td></tr>
<tr><td>SB1078, AB 2791 and SB 107</td><td>Directives</td><td>Distributed Generation
• The commission shall, for each electrical corporation, establish a pay-as-you-save pilot program for eligible customers, [who are defined as]:
  • The customer uses a combined heat and power system with a generating capacity of not more than 20 megawatts that is in compliance with Section 2843
  • A nonprofit organization described in Section 501(c) (3) of the Internal Revenue Code (26 U.S.C. Sec. 501(c) (3)), that is exempt from taxation under Section 501(a) of that code (26 U.S.C. Sec. 501(a)).
  • A federal, state, or local government facility (AB 2791, page 2)
• The pilot program shall enable an eligible customer to finance all of the upfront costs for the purchase and installation of a combined heat and power system by repaying those costs over time through on-bill financing at the difference between what an eligible customer would have paid for electricity and the actual savings derived for a period of up to 10 years (AB 2791, page 2)
• An additional objective of the program shall be to identify and support emerging renewable technologies in distributed generation applications that have the greatest near-term commercial promise and that merit targeted assistance (SB 107, page 10)
Other
• Beginning on January 1, 2003, each electrical corporation shall, pursuant to subdivision (a), increase its total procurement of eligible renewable energy resources by at least an additional 1 percent of retail sales per year so that 20 percent of its retail sales are procured from eligible renewable energy resources no later than December 31, 2017. An electrical corporation with 20 percent of retail sales procured from eligible renewable energy resources in any year shall not be required to increase its procurement of such resources in the following year (SB 1078, page 11)
• The commission shall develop, implement, and administer the Public Interest Research, Development, and Demonstration Program that is hereby created (SB 107, page 6)
• The general goal of the program is to develop, and help bring to market, energy technologies that provide increased environmental benefits, greater system reliability, and lower system costs, and that</td></tr>
</table>

		provide tangible benefits to electrical utility customers through investments in the following: • Advanced electricity generation technologies that exceed applicable standards to increase reductions in emissions of greenhouse gases from electricity generation, and that benefit electric utility customers • Advanced electricity technologies that reduce or eliminate consumption of water or other finite resources, increase use of renewable energy resources, or improve transmission or distribution of electricity generated from renewable energy resources (SB 107, page 6-7)
Public Resources Code Section 25524.1 and 25524.2	Directives	**Nuclear Generation** • Except for the existing Diablo Canyon Units 1 and 2 owned by Pacific Gas and Electric Company and San Onofre Units 2 and 3 owned by Southern California Edison Company and San Diego Gas and Electric Company, no nuclear fission thermal power plant, including any to which this chapter does not otherwise apply, but excepting those exempted herein, shall be permitted land use in the state, or where applicable, be certified by the commission until both of the following conditions have been met: a) The commission finds that there has been developed and that the United States through its authorized agency has approved and here exists a demonstrated technology or means for the disposal of high-level nuclear waste b) The commission has reported its findings and the reasons therefore to the Legislature (Public Resources Code 25524.1 and 25524.2)
Energy Policy Act of 2005	Goals	**Carbon Capture and Sequestration** • By 2020, coal gasification projects shall be able • To remove at least 99 percent of sulfur dioxide • To emit not more than .05 lbs of Nox per million Btu • To achieve at least 95 percent reductions in mercury emissions; and • To achieve a thermal efficiency of at least – • 50 percent for coal of more than 9,000 Btu • 48 percent for coal of 7,000 to 9,000 Btu • 46 percent for coal of less than 7,000 Btu (Energy Policy Act 2005, page 158) • In applying the thermal efficiency milestones …to projects that separate and capture at least 50 percent of the potential emissions of carbon dioxide by a facility, the energy used for separation and capture of carbon dioxide shall not be counted in calculating the thermal efficiency (Energy Policy Act 2005, page 160)
	Directives	**Carbon Capture and Sequestration** • $200 million per year from FY 2006 through FY 2014 is allocated to clean coal power initiatives (Energy Policy Act 2005, page 157) • To be eligible to receive assistance under this subtitle, a project shall advance efficiency, environmental performance, and cost competitiveness well beyond the level of technologies that are in commercial service or have been demonstrated on a scale that the Secretary determines is sufficient to demonstrate that commercial service is viable as of the date of enactment of this Act (Energy Policy Act 2005, page 158) • At least 70 percent of the funds are used only to fund projects on coal-based gasification technologies, including: • Gasification combined cycle • Gasification fuel cells and turbine combined cycle • Gasification coproduction • Hybrid gasification and combustion • Other advanced coal based technologies capable of producing a concentrated stream of carbon dioxide (Energy

Policy Act 2005, page 158)

- The Secretary shall carry out a 10-year carbon capture research and development program to develop carbon dioxide capture technologies on combustion-based systems for use in new coal utilization facilities and on the fleet of coal-based units in existence (Energy Policy Act 2005, page 299)
- The Secretary may provide loan guarantees for a project to produce energy from coal of less than 7,000 Btu/lb. using appropriate advanced integrated gasification combined cycle technology, including repowering of existing facilities, that –
  - is combined with wind and other renewable sources
  - minimizes and offers the potential to sequester carbon dioxide emissions; and
  - provides a ready source of hydrogen for near-site fuel cell demonstrations (Energy Policy Act 2005, page 162)
- The Secretary is authorized to provide loan guarantees for a project to produce energy from a plant using integrated gasification combined cycle technology of at least 400 megawatts in capacity that produces power at competitive rates in deregulated energy generation markets and that does not receive any subsidy (direct or indirect) from ratepayers (Energy Policy Act 2005, page 164)
- The Secretary shall carry out a program of financial assistance to
  - facilitate the production and generation of coal-based power, through the deployment of clean coal electric generating equipment and processes that, compared to equipment or processes that are in operation on a full scale improve energy efficiency or environmental performance
  - Facilitate the utilization of existing coal-based electricity generation plants (Energy Policy Act 2005, page 165)
- The Secretary shall ensure, to the extent practicable, that between 25 and 75 percent of the projects supported are for the sole purpose of electrical generation and priority is given to projects that use electrical generation equipment and processes that have been developed and demonstrated and applied in actual production of electricity, but are not yet cost-competitive, and that achieve greater efficiency and environmental performance (Energy Policy Act 2005, page 167)

Hydrogen

- The Secretary, in partnership with the private sector, shall conduct programs to address
  - production of hydrogen from diverse energy sources, including
    - fossil fuels, which may include carbon capture and sequestration
    - nuclear energy
  - use of hydrogen for commercial, industrial, and residential electric power generation (Energy Policy Act 2005, page 254)
- For hydrogen energy and energy infrastructure, the goals of the program are to enable a commitment not later than 2015 that will lead to infrastructure by 2020 that will provide:
  - Safe and convenient refueling
  - Improved overall efficiency
  - widespread availability of hydrogen from domestic energy sources through production, delivery and storage
  - Hydrogen for fuel cells, internal combustion engines, and other energy conversion devices for portable, stationary, micro, critical needs facilities, and transportation applications (Energy Policy Act 2005, page 255)
- The goals for fuel cells and their portable, stationary, and transportation applications are to enable
  - safe, economical, and environmentally sound hydrogen

fuel cells
- fuel cells for light duty and other vehicles; and
- other technologies consistent with the Department's plan (Energy Policy Act 2005, page 255)

Distributed Generation
- The Secretary shall carry out programs of research, development, demonstration, and commercial application on distributed energy resources and systems reliability and efficiency, to improve the reliability and efficiency of distributed energy resources and systems, integrating advanced energy technologies with grid connectivity, including activities described in this subtitle. The programs shall address advanced energy technologies and systems and advanced grid reliability technologies (Energy Policy Act 2005, page 272)
- There are authorized to be appropriated to the Secretary to carry out distributed energy and electric energy systems activities, including activities authorized under this subtitle:
  - $240,000,000 for fiscal year 2007;
  - $255,000,000 for fiscal year 2008; and
  - $273,000,000 for fiscal year 2009 (Energy Policy Act 2005, page 272)
- Micro-cogeneration energy technology—From amounts authorized under subsection (b), $20,000,000 for each of fiscal years 2007 and 2008 shall be available to carry out activities [such as]
  - the use of small-scale combined heat and power in residential heating appliances
  - the use of excess power to operate other appliances within the residence; and
  - the supply of excess generated power to the power grid (Energy Policy Act 2005, page 272-273)

Nuclear Generation
- The Secretary, acting through the Director of the Office of Nuclear Energy, Science and Technology, shall conduct an advanced fuel recycling technology research, development, and demonstration program (referred to in this section as the ''program'') to evaluate proliferation-resistant fuel recycling and transmutation technologies that minimize environmental and public health and safety impacts as an alternative to aqueous reprocessing technologies deployed as of the date of enactment of this Act in support of evaluation of alternative national strategies for spent nuclear fuel and the Generation IV advanced reactor concepts (Energy Policy Act 2005, page 294)
- The Secretary shall operate and maintain infrastructure and facilities to support the nuclear energy research, development, demonstration, and commercial application programs, including radiological facilities management, isotope production, and facilities management (Energy Policy Act 2005, page 295)

Natural Gas Power Plants
- The Secretary shall carry out research, development, demonstration, and commercial application programs in fossil energy, including activities under this subtitle, with the goal of improving the efficiency, effectiveness, and environmental performance of fossil energy production, upgrading, conversion, and consumption. Such programs take into consideration the following objectives:
  - Increasing the energy conversion efficiency of all forms of fossil energy through improved technologies
  - Decreasing the cost of all fossil energy production, generation, and delivery
  - Promoting diversity of energy supply
  - Decreasing the dependence of the United States on

		foreign energy supplies • Decreasing the environmental impact of energy-related activities (Energy Policy Act 2005, page 297) • There are authorized to be appropriated to the Secretary to carry out fossil energy research, development, demonstration, and commercial application activities, including activities authorized under this subtitle • $611,000,000 for fiscal year 2007; • $626,000,000 for fiscal year 2008; and • $641,000,000 for fiscal year 2009 (Energy Policy Act 2005, page 297) • The Secretary shall establish a national center or consortium of excellence in clean energy and power generation [which] shall conduct a program of research, development, demonstration, and commercial application on integrating the following 6 focus areas: • Efficiency and reliability of gas turbines for power generation • Reduction in emissions from power generation • Promotion of energy conservation issues • Effectively using alternative fuels and renewable energy • Development of advanced materials technology for oil and gas exploration and use in harsh environments • Education on energy and power generation issues (Energy Policy Act 2005, page 301) **Water Use for Generation** • The Secretary shall carry out a program of research, development, demonstration, and commercial application to • address energy-related issues associated with provision of adequate water supplies, optimal management, and efficient use of water • address water-related issues associated with the provision of adequate supplies, optimal management, and efficient use of energy; and • assess the effectiveness of existing programs within the Department and other Federal agencies to address these energy and water related issues (Energy Policy Act 2005, page 313) • The program under this section shall include arsenic treatment, desalination and planning, analysis, and modeling of energy and water supply and demand (Energy Policy Act 2005, page 313) **Other** • It shall be the policy of the United States to conduct research, development, demonstration, and commercial applications to provide for the scientific, engineering, and commercial infrastructure necessary to ensure that the United States is competitive with other countries in providing fusion energy for its own needs and the needs of other countries, including by demonstrating electric power or hydrogen production for the United States energy grid using fusion energy at the earliest date (Energy Policy Act 2005, page 308)
Energy Independence and Security Act of 2007	Directives	**Carbon Capture and Sequestration** • Programmatic Activities – Fundamental science and engineering research and development and demonstration supporting carbon capture and sequestration technologies and carbon use activities (Energy Independence and Security Act 2007, Section 702) • The Secretary shall ensure that fundamental research carried out under this paragraph is appropriately applied to energy technology development activities, the field testing of carbon sequestration, and carbon use activities, including • development of new or advanced technologies for the capture and sequestration of carbon dioxide • development of new or advanced technologies that

		reduce the cost and increase the efficacy of advanced compression of carbon dioxide required for the sequestration of carbon dioxide • modeling and simulation of geologic sequestration field demonstrations • quantitative assessment of risks relating to specific field sites for testing of sequestration technologies • research and development of new and advanced technologies for carbon use, including recycling and reuse of carbon dioxide • research and development of new and advanced technologies for the separation of oxygen from air (Energy Independence and Security Act 2007, Section 702) • The Secretary shall promote, to the maximum extent practicable, regional carbon sequestration partnerships to conduct geologic sequestration tests involving carbon dioxide injection and monitoring, mitigation, and verification operations in a variety of candidate geologic settings (Energy Independence and Security Act 2007, Section 702) • The Administrator of the Environmental Protection Agency shall conduct a research program to address public health, safety, and environmental impacts that may be associated with capture, injection, and sequestration of greenhouse gases in geologic reservoirs (Energy Independence and Security Act 2007, Section 707)
Energy Improvement and Extension Act of 2008	Directives	**Distributed Generation** • The bill extends the… 10 percent investment tax credit for microturbines through 2016 (Energy Improvement and Extension Act, page 1) • The bill increases the $500 per half kilowatt of capacity cap for qualified fuel cells to $1,500 per half kilowatt of capacity (Energy Improvement and Extension Act, page 1) • The bill also provides a new 10 percent investment tax credit for combined heat and power systems and geothermal heat pumps (Energy Improvement and Extension Act, page 1) • The estimated cost of this proposal is $1.942 billion over 10 years (Energy Improvement and Extension Act, page 1) **Carbon Capture and Sequestration** • The bill provides $1.5 billion in new tax credits for the creation of advanced coal electricity projects (Section 48A) and certain coal gasification projects (Section 48B) that demonstrate the greatest potential for carbon capture and sequestration (CCS) technology (Energy Improvement and Extension Act, page 2) • Of these $1.5 billion of incentives, $1.25 billion will be awarded to advanced coal electricity projects, and $250 million will be awarded to coal gasification projects (Energy Improvement and Extension Act, page 2) • Applications will not be considered unless they can demonstrate that either their advanced coal electricity project would capture and sequester at least 65 percent of the facility's CO2 emissions or that their coal gasification project would capture and sequester at least 75 percent of the facility's CO2 emissions (Energy Improvement and Extension Act, page 2) • The estimated cost of this proposal is $1.424 billion over 10 years (Energy Improvement and Extension Act, page 2)
American Recovery and Reinvestment Act of 2009	Directives	**Carbon Capture and Sequestration** • $2,400,000,000 for necessary expenses to demonstrate carbon capture and sequestration technologies as authorized under section 702 of the Energy Independence and Security Act of 2007 (American Recovery and Reinvestment Act of 2009, page 73)

ARB AB 32 Scoping Plan	Goals	• This measure sets a target of an additional 4,000 MW of installed CHP capacity by 2020, enough to displace approximately 30,000 GWh of demand from other power generation sources (ARB AB 32 Scoping Plan, page 43)
	Directives	• Increase CHP generation by 30,000 GWh (ARB AB 32 Scoping Plan, page 17) • High-efficiency distributed generation applications like fuel cell technologies can also play an important role in helping the State meet its requirements for reduction of greenhouse gas emissions (ARB AB 32 Scoping Plan, page 42) • Innovative financing [is needed] to overcome first-cost and split incentives for energy efficiency, on-site, renewables, and high efficiency distributed generation (ARB AB 32 Scoping Plan, page 42) • In response to a lower cap on emissions, existing coal generation contracts would not be renewed, or carbon capture and storage would be utilized to minimize emissions. The remaining electricity generation would come from natural gas combustion either in cogeneration applications or from highly efficient generating units (ARB AB 32 Scoping Plan, page 119)
CEC Committee Report: CEQA Responsibilities for GHG Impacts in Power Plant Siting	Directives	• A system that increasingly relies on renewable generation for energy must likewise provide gas-fired dispatchable *capacity* to make the system reliable when intermittent renewable generators are providing less (CEC Committee Report, page 24) • Although California has very limited installed coal-fired- power plants in-state, California utilities and load-serving entities import 16 percent of annual electricity energy from out-of-state coal plants (CEC Committee Report, page 24) • The *2007 IEPR* describes gas as the potential "swing fuel" for displacing coal-fired power in the scenario analysis (CEC Committee Report, page 24) • Staff should prepare or oversee the development of a "blueprint" laying out the role for different generation technologies, and identifying the amount and type of capacity required for 2013 and 2020 to support high levels of renewable additions, expansion of energy efficiency efforts and other demand-side programs, retirement of aging coastal facilities relying on once-through cooling, and providing reliability for individual load pockets (CEC Committee Report, page 29) • Staff should prepare an analysis comparing the degree that different kinds of gas-fired power plants facilitate AB 32 goals, and whether (or the degree to which) project technology and location may make a proposed power plant more consistent with AB 32 goals (CEC Committee Report, page 29) • Staff should conduct an analysis of generation additions required in the South Coast air district to satisfy demand growth, close or repower aging coastal facilities using once-through cooling technologies, and meet other IEPR goals (CEC Committee Report, page 30)

Draft CEC PIER-EA Discussion Paper: Environmental Justice	Directives	• Recognizing the likelihood of increasing disproportionate and cumulative impacts in such communities as a result of GHG emission reduction efforts, AB 32 requires that its regulations and compliance mechanisms:
		  • Do not disproportionately impact low-income communities;
		  • Consider the potential for direct, indirect and cumulative emission impacts in communities that are already impacted by air pollution;
		  • Prevent any increase in the emissions of toxics or criteria pollutants; and
		  • Direct public and private investment toward the most disadvantaged communities. (Environmental Justice, page 4)

PIER Overview of Environmental Justice Requirements	Directives	• Ensure that power plant siting will not disproportionately affect minority and low-income communities (PIER Overview of EJ Requirements, page 3)
Clean Water Act, Section 316(b)	Directives	• Since 1972, the Clean Water Act has required, in Section 316 (b), that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. (Clean Water Act, Section 316(b))
PIER Electricity Research Investment Five Year Plan	Directives	• Reduce cost and improve system and environmental performance of alternative generation systems (Five Year Plan, page 20) • Develop adequate generation resources that are diverse and flexible (Five Year Plan, page 20) • Understand the nature/significance of climate change; its relationship to electricity generation and use; development of strategies for greenhouse gas reduction; and strategies for mitigation/adaptation of impacts (Five Year Plan, page 32) • Improve the understanding of, and develop solutions for, reducing biological, land use, air quality, and water-related impacts of the electricity system and contribute to a sustainable energy future (Five Year Plan, page 32)

7.3. Technology Profile References

Table 75: References Used in Technology Profiles

Distributed Generation	
Research Source	**Reference Symbol**
www.dsireusa.org	(DG1)
http://www.epa.gov/chp/documents/utility_incentives.pdf	(DG2)
http://www.epa.gov/chp/funding/funding/uschpinvestmenttaxcredit.html	(DG3)
http://www.energy.ca.gov/2005publications/CEC-500-2005-173/CEC-500-2005-173.PDF	(DG4)
Fuel Cells	
"Central and Downtown Toronto DG Study Technical Workshop – DG Technology Characteristics“, Navigant Report	(FC1)
http://www.fuelcells.org/	(FC2)
http://www.nfcrc.uci.edu/2/FUEL_CELL_INFORMATION/FCexplained/FC_Types.aspx	(FC3)

http://www.epa.gov/chp/basic/catalog.html	(FC5)
http://www.tiaxllc.com/d/alternative_fuels.php	(FC6)
http://corrosion-doctors.org/FuelCell/mcfc.htm	(FC7)
"Catalog of CHP Technologies", US EPA and Combined Heat and Power Partnership, Dec. 2008	(FC8)
"The market and technical potential for CHP in the Commercial/Industrial Sector" ONSITE SYCOM Energy Corporation report, Jan. 2000'	(FC9)
http://www.fuelcells.org/basics/fuelcellsavings.pdf	(FC10)
"Inventory of Emerging DR Technologies."	(FC11)
http://www.fuelcells.org/2008StatesH2FCWrapUp.pdf	(FC12)
http://www.nfcrc.uci.edu/2/FUEL_CELL_INFORMATION/FCexplained/challenges.aspx	(FC13)
http://www.modernpowersystems.com/story.asp?storycode=2052805	(FC14)
http://www.powergeneration.siemens.com/products-solutions-services/products-packages/fuel-cells/seca-program-schedule/	(FC15)
http://www.netl.doe.gov/onsite_research/EnergySystem.html	(FC16)
http://hydrogen.energy.gov/fuel_cells.html	(FC17)
http://www.usfcc.com/resources/EM.FuelCellTaxIncentives.FAQs.PressRelease-05-166.pdf	(FC18)
http://www.hydrogen.energy.gov/annual_progress08.html	(FC19)
http://www.hydrogen.energy.gov/pdfs/progress08/i_introduction.pdf	(FC20)
http://www.fuelcells.org/info/StateActivity.pdf	(FC21)
http://www.fuelcells.org/info/2008StatesH2FCWrapUp.pdf	(FC22)

http://www.fuelcells.org/dbs/project.php?id=1126	(FC23)
http://www.fuelcells.org/dbs/project.php?id=1130	(FC24)
http://www.casfcc.org/2/StationaryFuelCells/PDF/USDOEFundingOpportunityAnnouncement.pdf	(FC25)
http://www.nfcrc.uci.edu/2/ACTIVITIES/marketDynamics/FC4.aspx	(FC26)
"Renewable and Distributed Generation and Nuclear Technology Update“, Navigant Report, 2004	(FC27)
http://www.energy.ca.gov/distgen/equipment/fuel_cells/cost.html	(FC28)
http://www.energy.gov/news2009/7262.htm	(FC29)
http://www.intelligent-energy.com/index_article.asp?SecID=5&secondlevel=76&artid=3988	(FC30)
http://www1.eere.energy.gov/femp/pdfs/fuelcell_tir.pdf	(FC31)
http://ec.europa.eu/research/energy/pdf/efchp_fuelcell15.pdf	(FC32)
http://books.google.com/books?id=ugniowznToAC&pg=PA32&lpg=PA32&dq=PAFC+CHP+efficiency&source=bl&ots=nv9ly2tQmK&sig=usMyP2IKsgaG56Oe0CzmPOBzXA0&hl=en&ei=v48mSq7JMMfBtwfOqIntBg&sa=X&oi=book_result&ct=result&resnum=1	(FC33)
http://books.google.com/books?id=C5oJLmLWq-gC&pg=PA57&lpg=PA57&dq=PAFC+CHP+efficiency&source=bl&ots=b3Xjx2D1TY&sig=izZU_L18elltAFx8lzxBup2ZGTI&hl=en&ei=v48mSq7JMMfBtwfOqIntBg&sa=X&oi=book_result&ct=result&resnum=7#PPA57,M1	(FC34)
"The Future of Renewable and Emerging Generation Technologies", FuelCell Energy Presentation, Power-Gen International 2005	(FC35)
http://www.netl.doe.gov/publications/press/2007/07039-SECA_Concludes_Phase_I.html	(FC36)
http://www.powergeneration.siemens.com/products-solutions-services/products-packages/fuel-cells/	(FC37)
CEC Report, CEC-200-2007-011 APB	(FC38)
http://www.energy.ca.gov/research/epag/research_plans/epag_fuelcells.html	(FC39)

http://www.energy.ca.gov/2009publications/CEC-500-2009-064/CEC-500-2009-064-CMF.PDF	(FC40)
http://books.google.com/books?id=ugniowznToAC&pg=PA32&lpg=PA32&dq=PAFC+CHP+efficiency&source=bl&ots=nv9ly2tQmK&sig=usMyP2IKsgaG56Oe0CzmPOBzXA0&hl=en&ei=v48mSq7JMMfBtwfOqIntBg&sa=X&oi=book_result&ct=result&resnum=1	(FC33)
http://books.google.com/books?id=C5oJLmLWq-gC&pg=PA57&lpg=PA57&dq=PAFC+CHP+efficiency&source=bl&ots=b3Xjx2D1TY&sig=izZU_L18eIltAFx8lzxBup2ZGTI&hl=en&ei=v48mSq7JMMfBtwfOqIntBg&sa=X&oi=book_result&ct=result&resnum=7#PPA57,M1	(FC34)
"The Future of Renewable and Emerging Generation Technologies", FuelCell Energy Presentation, Power-Gen International 2005	(FC35)
http://www.netl.doe.gov/publications/press/2007/07039-SECA_Concludes_Phase_I.html	(FC36)
http://www.powergeneration.siemens.com/products-solutions-services/products-packages/fuel-cells/	(FC37)
CEC Report, CEC-200-2007-011 APB	(FC38)
http://www.energy.ca.gov/research/epag/research_plans/epag_fuelcells.html	(FC39)
http://www.energy.ca.gov/2009publications/CEC-500-2009-064/CEC-500-2009-064-CMF.PDF	(FC40)
Hybrid Fuel Cell Gas Turbines	
http://www.fuelcellenergy.com/files/FCE percent20WhitePaper percent20040308_2.pdf	(HF1)
http://www.fuelcellenergy.com/files/Hybrid percent20Power percent20System percent20Thrust percent20Area.pdf	(HF2)
"The Gas Turbine Handbook", Chpt 1.4, DOE Office of Fossil Energy/NETL 2006	(HF3)
"The Future of Renewable and Emerging Generation Technologies", FuelCell Energy Presentation, Power-Gen International 2005	(HF4)
"Solar Turbines Perspective on Advanced Fuel Cell/Gas Turbine Systems", D.J. White, Paper No.:DOE/MC/30246-97/C0774, Fuel Cells '96 Review Meeting	(HF5)
http://www.independent.co.uk/news/business/news/rollsroyce-considers-options-to-take-green-fuel-cell-commercial-777340.html	(HF7)
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http://www.energy.ca.gov/research/epag/research_plans/epag_hybrids.html	(HF10)
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Reciprocating Engines	
http://www.epa.gov/chp/documents/catalog_chptech_reciprocating_engines.pdf	(RG1)
http://www.epa.gov/chp/documents/catalog_chptech_full.pdf	(RG2)
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http://www.eere.energy.gov/de/gas_fired/	(RG5)
http://www.eere.energy.gov/de/pdfs/ares_program.pdf	(RG6)
http://www.gocpc.com/DGin percent20OregonOverview.pdf	(RG7)
http://www.energy.ca.gov/distgen/interconnection/interconnection.html	(RG8)
http://itecsinsider.com/?p=2308	(RG9)
http://www1.eere.energy.gov/industry/newsandevents/news_detail.html?news_id=12201	(RG10)
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