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Combined Heat and Power Report, 2010

Maine Governor's Office of Energy Independence and Security

COMBINED HEAT and POWER REPORT

July, 2010

John E. Baldacci
Governor
State of Maine

John M. Kerry
Director
Governor's Office of Energy
Independence and Security

STATE OF MAINE
OFFICE OF THE GOVERNOR
22 STATE HOUSE STATION
AUGUSTA, MAINE
04333-0001

JOHN ELIAS BALDACCI
GOVERNOR

JOHN M. KERRY
DIRECTOR
OFFICE OF ENERGY
INDEPENDENCE AND SECURITY

July 1, 2010

Honorable Barry J. Hobbins, Senate Chair
Honorable Jon Hinck, House Chair
Joint Standing Committee on Utilities and Energy
115 State House Station
Augusta, Maine 04333-0115

RE: Combined Heat and Power, Report July 2010

Dear Senator Hobbins and Representative Hinck:

The 123rd Legislature enacted "Resolve, To Encourage Renewable Energy and Energy Conservation in Maine."

As directed, the Governor's Office of Energy Independence and Security (OEIS) prepared the accompanying report to "examine opportunities for energy conservation through the reuse of waste heat and make recommendations for eliminating barriers to and creating incentives for the installation of systems that conserve energy through the reuse of waste heat." The report, "Combined Heat and Power, July 2010," also examines technical and policy issues and makes recommendations to encourage such systems.

The 124th Legislature enacted "Resolve, To Promote Cogeneration of Energy at Maine Sawmills." This report responds to the Resolve's request to the OEIS to examine and make recommendations regarding the concept of cogeneration energy zones to promote cogeneration at sawmills in the State.

If you have any questions regarding the report, please do not hesitate to contact us.

Sincerely,

John M. Kerry

PHONE: (207) 287-3292

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SPECIAL ACKNOWLEDGEMENTS

I would like to offer special thanks to Erika Lloyd, Project Manager of Woodard & Curran for overseeing, coordinating and drafting this report.

ACKNOWLEDGEMENTS

I would like to thank Paul Aubrey, President of Technical Support, Inc. & Self-Gen, Inc. for his role in drafting this report. Additionally, I also want to thank members of the Governor's Office of Energy Independence and Security for their assistance with this report, including Jennifer Puser (Deputy Director of Research and Legislation), Jeffrey Marks (Deputy Director of Policy and Planning), and intern Nik Rodrigues. Lastly, I would like to thank the stakeholder group for their participation, educational information sharing, stimulating discussions, and input for this report. In particular I would like to thank Ian Burnes, former Deputy Director of Policy and Planning and now with the Efficiency Maine Trust, for his help with this report and his initial involvement organizing the taskforce.

EXECUTIVE SUMMARY

The United States has become dangerously dependent on foreign energy sources that are warming the earth, damaging the environment, threatening public health, undermining our economic vitality, eroding national security and diminishing our quality of life. The State of Maine exports more than $5 billion dollars each year because of its inordinate dependence on foreign oil. State and national energy policies need to support clean, renewable and affordable energy sources; in addition, the United States and the State of Maine need to employ more energy efficient technologies such as Combined Heat and Power (CHP) to save money and to advance our environmental and economic goals. Accordingly, the Governor's Office of Energy Independence and Security believes that a public policy environment needs to be established to create public-private partnerships that enable the State of Maine to take the bold steps needed to employ technologies such as CHP to secure a reliable, affordable and clean energy future.

CHP is an efficient, clean and reliable integrated "systems" approach to generating power and thermal energy from a single fuel source. CHP systems can significantly increase a facility's operational efficiency, decrease energy costs and reduce greenhouse gas emissions that contribute to climate change. CHP provides onsite, distributed generation of electrical power; waste-heat recovery for heating, cooling or process applications; and integration of a variety of technologies and fuel types into a facility's infrastructure. The energy efficiency, renewable energy, reliability, environmental quality and economic development benefits of CHP make it an attractive option to meet the goals of the State of Maine Comprehensive Energy Action Plan.

CHP technologies are available for a wide range of applications and uses, including industrial manufacturers (pulp and paper); institutions (universities, hospitals, prisons); commercial buildings (hotels, office buildings, airports); municipalities (district energy systems, wastewater treatment facilities, schools); and residential (multi-family housing). Depending on the facility type and size, CHP projects can be designed according to required components (heat engine, generator, heat recovery and electrical connection); prime mover (gas turbine, micro-turbines, reciprocating engine, steam turbine, fuel cell); and fuel source (natural gas, biomass and bio-fuels, waste heat, oil).

While the benefits are apparent, the use of CHP faces barriers and has thus far been underutilized in the market. The primary hurdles include, but are not limited to, fuel infrastructure, utility rate designs and interconnection issues. Fortunately, federal, state and regional governments and organizations are developing information resources and advocating for legislative and regulatory initiatives that will support the CHP industry. These efforts include support for financial incentives and policy initiatives targeting CHP and waste energy recovery programs. Appropriations, tax credits, renewable and energy efficiency programs, climate change revenues, standard interconnection regulations and other proposals are circulating in policy arenas around the country.

State partnerships with energy consumers, the CHP and natural gas industries, the U.S. Department of Energy, municipalities and other stakeholders are essential to facilitate the development of new projects, policies and resources in Maine. The Maine Legislature and Governor should review and consider all potential options to promote financial and policy tools for CHP development, including tax incentives, regulatory incentives and market-based approaches. The result will be deployment of technologies that will increase Maine's energy security, foster environmental quality and provide economic development opportunities and jobs in Maine.

The Governor's Office of Energy Independence and Security (OEIS) recommends consideration of the following policies, initiatives and action items:

- Establishment of an interconnection stakeholder taskforce by the Maine Public Utilities Commission (MPUC) to review and further explore how to streamline the technical and economic guidelines or requirements in order to quickly move CHP projects forward throughout the State of Maine.
- Review and further exploration of cost shifting to rate payers associated with utilities' potential lost revenue from CHP projects. This analysis should quantify the cost shifting, explore whether these rates and charges are creating unwarranted barriers to the use of renewable CHP projects, examine alternative rate designs and quantify and compare the system-wide benefits that CHP may provide.
- Pursuit of a Maine Energy Independence Fund (MEIF) which is a proposed public-private partnership that would match a potential federal grant or loan one to one with private investments. Funds would be invested in small-to-medium sized clean energy projects and companies located in Maine. These funds would also help with the project development costs.
- Expansion of natural gas in Maine as recommended in the Maine Comprehensive Energy Action Plan to reduce dependence on oil.
- Support for Congressional Delegation and Administration activities on Federal energy initiatives that seek to strengthen renewable energy, energy efficiency and CHP policies and programs.
- Support for current legislative and regulatory advocacy for strong CHP policies and programs.
- Establishment of a DOE/Maine Memorandum of Understanding (DOE-Maine Clean Energy and Efficiency Partnership) to integrate national and state energy, environmental and economic policies into a cohesive and sustainable energy strategy.
- Implement Grants Connector program to connect Maine businesses, institutions and other entities with federal and state financial opportunities for CHP projects.
- Fully implement An Act Regarding Maine's Energy Future (LD 1485), putting Maine on a path to reduce statewide heating oil consumption 20% by 2020.

1. INTRODUCTION

1.0 INTRODUCTION

Maine is inordinately dependent on foreign sources of fossil fuels to heat and power its homes and businesses. The Maine Comprehensive Energy Action Plan provides the framework for state and local governments, businesses, factories, buildings and residences to invest in energy efficiency, conservation and renewable and alternative clean energy. To accelerate the transformative process from a state dependent on oil to one that develops and uses energy efficiency and renewable technologies, Maine must make available the financial, regulatory and policy support for CHP applications.

Maine is making recognizable positive strides in energy efficiency. According to the 2009 State Energy Efficiency Scorecard, Maine ranked tenth, moving up 9 spots and into the "top-ten" (ACEEE, Oct. 2009). The American Council for an Energy-Efficient Economy (ACEEE) State Energy Efficiency Score Card ranks and scores states on adoption and implementation of energy efficiency policies and programs based on six categories: (1) utility-sector and public benefits programs and policies, (2) transportation policies, (3) building energy codes, (4) combined heat and power, (5) state government initiatives, and (6) appliance efficiency standards. The "top-ten" states lead the country in energy efficiency through best practices in most of the six ranking categories. Maine moved into the 'top-ten" due to a variety of increased energy efficiency efforts, including adoption of building energy codes, land-use planning management, Efficiency Maine efforts, and other activities (ACEEE, Oct. 2009). Through the information and guidance provided in this report, the OEIS strives to transform Maine into a leader on CHP as well.

1.1 PURPOSE OF REPORT

The purpose of this report is to provide information and recommendations pursuant to:

- LD 2149 "Resolve, To Encourage Renewable Energy and Energy Conservation in Maine" from the 123rd Legislature; and
- LD 1044 "Resolve, To Promote Cogeneration of Energy at Maine Sawmills" from the 124th Legislature.

This report will clearly define the technical background and benefits related to combined heat and power and waste heat recovery, provide examples of existing CHP facilities in Maine, identify barriers and current incentives for the installation of CHP systems, and make recommendations pursuant to our directive.

1.2 DEVELOPMENT OF COMBINED HEAT AND POWER STAKEHOLDER GROUP

Pursuant to its directive, the OEIS convened a stakeholder group in June 2009, which consisted of representatives from various groups, including the Energy Resource Commission (ERC), MPUC, the office of the Public Advocate, representatives from the forest products industry and transmission and distribution utilities, project developers and engineering firms, industrial users, economic development entities, and environmental groups.

The stakeholder group met in July, August, September, and December of 2009. The meeting goals were to define the stakeholder group's terms and the group was charged with making recommendations for eliminating/overcoming barriers and creating incentives for the installation of systems that conserve energy through the reuse of waste heat. To lay the technical foundation and to promote discussions, relevant and informative presentations were given by the members of the stakeholder group during the meetings. Copies of these presentations can be found in Appendix A.

1.3 MEMBERS OF CHP STAKEHOLDER GROUP

The following is a list of members of the established CHP Stakeholder Group:

Manisha Aggarwal, TransCanada
Glen Albee, Hancock Lumber
David Allen, Central Maine Power
Cynthia Armstrong, Portland Natural Gas Transmission System
Paul Aubrey, TSI / Self-Gen
Kathy Billings, Bangor Hydro
Rick Buotte, Bureau of General Services
Bruce Bornstein, Isaacson Lumber Company
Ian Burnes, Efficiency Maine
Patrick C. Cannon, Maine Public Service
Dick Davies, Maine Public Advocate
Stacy Dimou, Consultant
Joel Farley, Eastern Maine Medical Center
Stacy Fitts, House Representative, District 29
Ken Fletcher, House Representative, District 54
Chip Gavin, Maine Bureau of General Services
Todd Griset, Preti Flaherty
Marylee Hanley, Maritimes Northeast
John Joseph, JAI Software
John Kerry, Governor's Office of Energy Independence and Security
Christopher J. Leblanc, Unitil
Gus Libby, Colby College
Jerry Livengood, Bangor Natural Gas
Erika Lloyd, Woodard & Curran
Angela Monroe, Maine Public Utilities Commission
Jeff Mylen, Eastern Maine Medical Center
Tyler Player, Maine Public Service
Darrel Quimby, Maine Natural Gas
Jim Robbins, Robbins Lumber INC
Steve Schley, Pingree Associates
Mike Smith, Unitil
Patrick Strauch, Maine Forest Product Council
Sharon Sudbay, Maritimes and Northeast Pipeline
Don Tardie, Maine Woods Company
Greg Thompson, Self-Gen
Mary Usavic, REPSOL

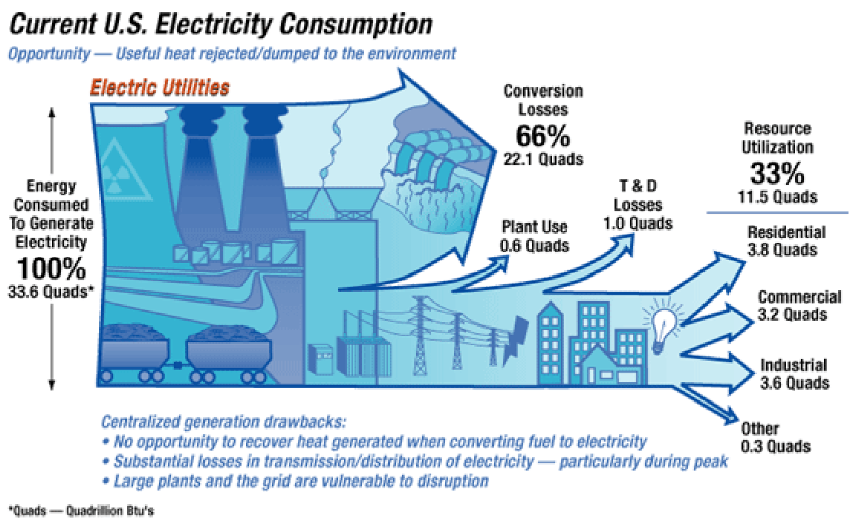
OEIS prepared this report with significant guidance and information provided by the CHP Stakeholder Group. However, while the report reflects the consensus of the CHP Stakeholder Group, some content and opinions expressed in the report may not reflect the positions of every Member of the Group.

2. COMBINED HEAT AND POWER

2.0 WHAT IS COMBINED HEAT AND POWER

CHP, also known as cogeneration, is a specific form of distributed generation (DG) which relates to the strategic placement of electric power generation units at or near customer facilities to supply on-site energy needs (US EPA, 2008). CHP enhances the advantages of DG by the concurrent production of thermal energy (heating or cooling) and electricity or mechanical power from a single fuel source, such as natural gas, biomass, biogas, coal, waste heat, or oil. CHP is not a single technology but rather an integrated energy system that can be customized and designed based on the needs of the energy end users' thermal (heating and cooling) baseload demand. More than two-thirds of our natural resources (mostly coal and natural gas) used to generate power are lost as waste heat to the environment (NREL, 2010). See Figure 2-1 which shows the current U.S Electricity Consumption.

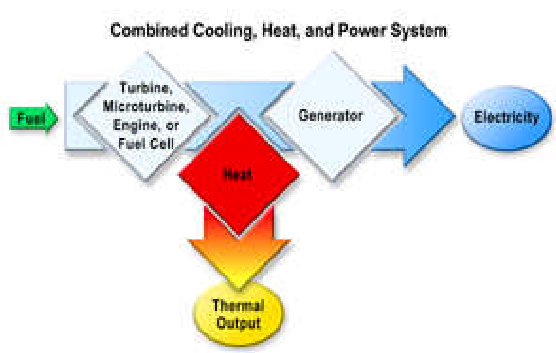
Figure 2-1: Current U.S. Electricity Consumption



Source: http://www.nrel.gov/dtet/about.html

The CHP energy model allows the heat (thermal energy) that would normally be lost in the power generation process to be recovered to provide thermal energy that can be used for process steam, hot water heating, space heating and cooling, and process cooling. See Figure 2-2 which shows a combined heat and power system diagram.

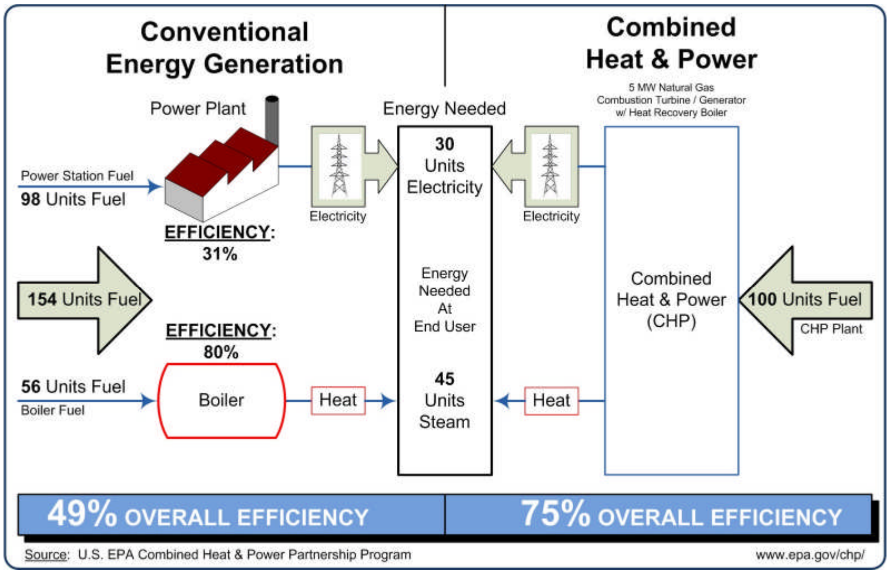
Figure 2-2: Combined Heat & Power System



Source: http://www.in.gov/oed/2414.htm

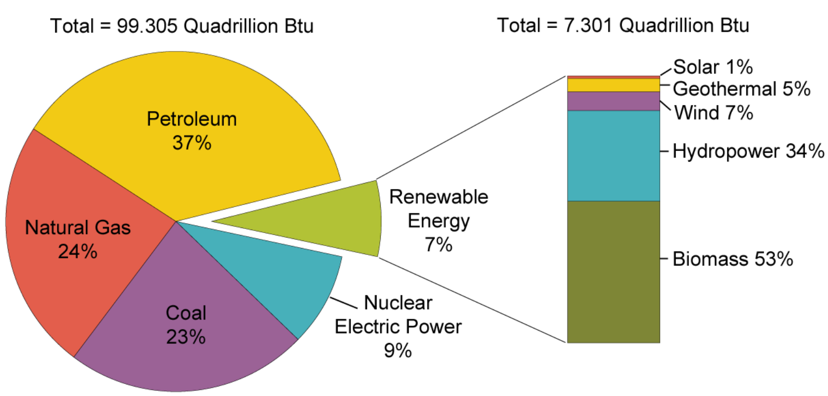
The CHP energy model can improve a facility's operational efficiency and decrease energy costs, as well as reducing greenhouse gas emissions. Figure 2-3 shows a comparison between conventional central utility power station generation and onsite boilers and the CHP energy model. CHP normally requires only ¾ the primary energy that separate heat and power systems require. Additionally, CHP systems utilize less fuel to achieve the same level of output, while producing fewer emissions (US EPA, 2008).

Figure 2-3: Separate Heat and Power Production versus Combined Heat & Power



In 2008, consumption of renewable sources in the United States totaled 7.3 quadrillion Btu or about 7% of all energy used nationally. Over half of renewable energy goes to producing electricity. About 9% of U.S. electricity was generated from renewable sources in 2008. The next largest use of renewable energy is the production of heat and steam for industrial purposes. Renewable fuels, such as ethanol, are also used for transportation fuels and bio-oil provides heat for homes and businesses (US EPA, 2010a).

The Role of Renewable Energy in the Nation's Energy Supply, 2008

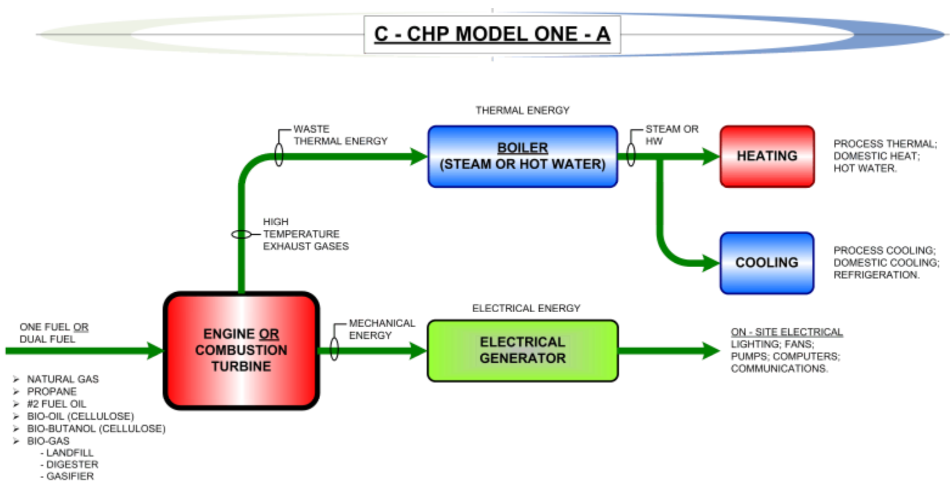


Note: Sum of components may not equal 100% due to independent rounding.
Source: Energy Information Administration, *Renewable Energy Consumption and Electricity Preliminary Statistics 2008*, Table 1: U.S. Energy Consumption by Energy Source, 2004-2008 (July 2009).

CHP plays an important role in meeting the United States' renewable energy needs as well as in reducing the environmental impact of power generation (US EPA, 2010a).

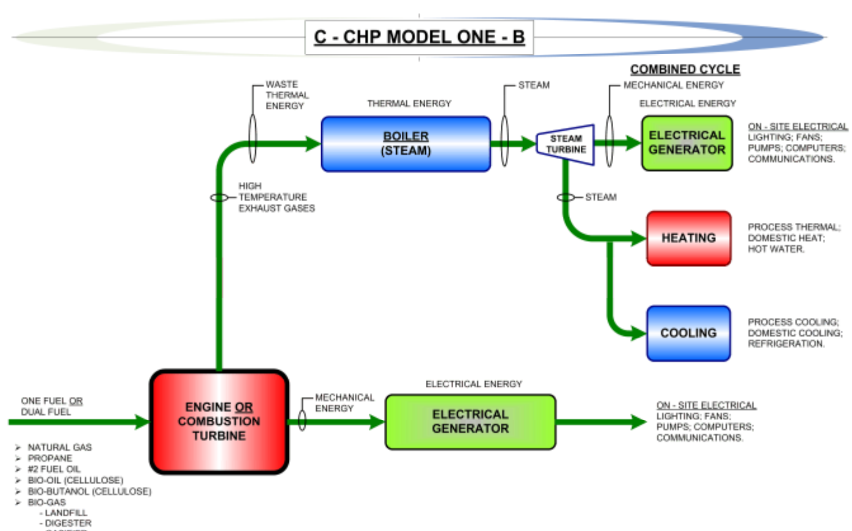
2.1 TYPES OF CHP SYSTEMS

There are two basic energy conversion models for CHP systems with variations on each model utilizing CHP technologies or systems that are suitable to the application. Several hybrid models exist but for this report the two most common models are identified. For Model 1A, the energy conversion process starts with the fuel, which is converted into mechanical energy; this mechanical energy is then converted into electrical energy; finally, recovered waste thermal energy is converted into steam or hot water.



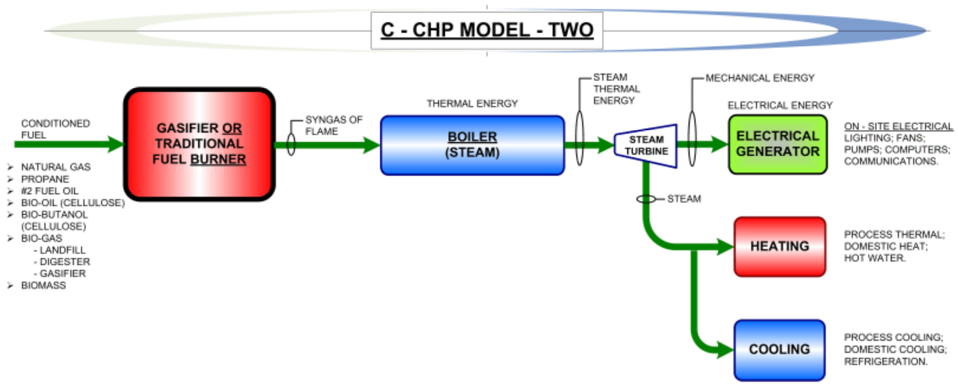
Source: Self-Gen, Inc.

For Model 1B, the energy conversion process starts with the fuel, which is converted into mechanical energy; this mechanical energy is then converted into electrical energy; finally, recovered waste thermal energy is converted into steam or hot water for heating and cooling needs of the host site. However, for Model 1B the waste thermal energy is first converted to mechanical energy to create additional electrical energy and finally the remaining recovered waste thermal energy is used for heating and cooling loads. This energy model is defined as a combined cycle where electrical energy is created twice during the energy conversion process.



Source: Self-Gen, Inc.

For Model 2, the energy conversion process starts with the fuel which is converted into thermal energy first (usually high pressure steam); the steam is then converted to mechanical energy (steam turbine) that is used to create electrical energy; and finally, recovered waste thermal energy from the steam turbine is utilized for heating and cooling needs of the host site.



Source: Self-Gen, Inc.

For each CHP energy conversion model there are many technologies available for each phase of the energy conversion process. Suitability-to-application should always be one of the key criteria when considering which energy conversion model and associated technologies to utilize for each site specific application. A vendor-neutral energy expert should be engaged when determining the best energy conversion model and associated technologies.

CHP systems consist of a number of individual components which are configured into an integrated system. The table below defines the typical components based on the energy conversion model utilized.

Table 2-1: Typical Components Based on Energy Conversion Model

CHP Core Component	Component Description	**Model 1A** *Fuel-to-Mechanical Energy-to-Electrical Energy & Waste Thermal Energy Recovery*	**Model 1B** *Fuel-to-Mechanical Energy-to-Electrical Energy & Waste Thermal Energy Recovery-to-Mechanical Energy-to-Electrical Energy & Waste Thermal Energy Recovery*	**Model 2** *Fuel-to-Thermal Energy-to-Mechanical Energy-to-Electrical Energy & Waste Thermal Energy Recovery*
Combustion Turbine/Generator	Converts fuel into mechanical energy to electrical energy with high temperature waste exhaust gases for thermal energy recovery & conversion	Yes	Yes	No
Reciprocating Engine/Generator	Converts fuel into mechanical energy to electrical energy with high temperature waste exhaust gases, jacket water & lube oil cooler for thermal energy conversion	Yes	Yes	No
Micro-Turbine/Generator	Converts fuel into mechanical energy to electrical energy with high temperature waste exhaust gases for thermal energy recovery & conversion	Yes	No (combined cycle models are for larger systems)	No
Exhaust Gas Waste Heat Steam Generator or Boiler (HRSG)	Converts waste high temperature exhaust gases into steam or hot water	Yes	Yes	No
Jacket Water & Lube Oil Cooling Heat Exchangers	Converts waste thermal energy from jacket water and lube oil coolers into hot water	Yes	Yes	No
Gasifier/Boiler	Converts solid waste fuel (biomass) into a syngas that is used to make high pressure steam in a boiler	No	No	Yes
Stoker Solid Fuel Boiler	Converts solid waste fuel (biomass) into a thermal energy that is used to make high pressure steam in a boiler	No	No	Yes
Fluidized Bed Solid Fuel Boiler	Converts solid waste fuel (biomass) into a thermal energy that is used to make high pressure steam in a boiler	No	No	Yes
Steam Turbine	Converts steam into mechanical energy	No	Yes	Yes
Generator	Converts mechanical energy into electricity	No	Yes	Yes
Economizer	Recovers thermal energy from boiler flue gases for energy optimization	No	No	Yes
Absorption Chiller	Coverts steam or hot water into chilled water for cooling energy	Yes	Yes	Yes
Steam Turbine Chiller	Converts steam into mechanical energy to drive a chiller for sub-40 deg. refrigeration or freezer cooling applications	Yes	Yes	Yes
Fuel Cells (three types)	Electro-chemical energy conversion process for electrical and thermal energy production. Can be integrated with other CHP technology components	Possible	Possible	Possible with Digester
Power Interconnection	Power system interconnection equipment to include switchgear or switchboard. Protective relaying, metering and controls.	Yes	Yes	Yes
Automation & Controls	Process automation and controls including PLC or DCS and operator interface station	Yes	Yes	Yes

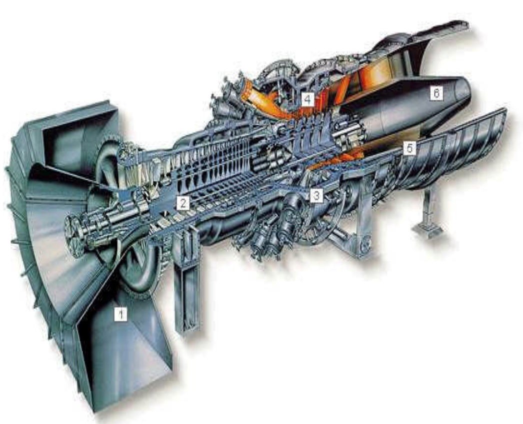
The CHP prime mover typically identifies the CHP components and there are five principle types:

1. Combustion or gas turbines;
2. Micro-turbines;
3. Reciprocating engines;
4. Steam turbines; and
5. Fuel cells.

These prime movers are able to burn a variety of fuels such as natural gas, coal, oil, and alternative fuels such as biomass, bio-gas, or bio-fuels to produce mechanical or thermal energy. Typically this mechanical energy is used to power a generator to produce electricity; however it can also be used to power rotating equipment including compressors, pumps, and fans (US EPA, 2008). The recovered thermal energy from the CHP system can be used two different ways: "in direct process application or indirectly to produce steam, hot water, hot air for drying, or chilled water for process cooling" (US EPA, 2008). The following subsections will briefly describe the five different types of CHP prime movers. Detailed information can be found in the Catalog of CHP Technologies, Appendix B.

2.1.1 Combustion or Gas Turbines with Heat Recovery

Combustion or gas turbines are much like a jet aircraft engine coupled to an electric generator. It's an internal-combustion engine consisting essentially of an air compressor, combustion chamber, and turbine wheel that is turned by the expanding products of combustion. Gas turbines can be used in a variety of configurations: (1) a single gas turbine producing power only, referred to as simple cycle operation, (2) a simple gas turbine with a heat recovery heat exchanger, which recovers the heat in the turbine exhaust and converts it to useful thermal energy, referred to as CHP operation, or (3) where high pressure steam is produced from the recovered exhaust heat and used to create additional power using a steam turbine/generator, referred to as combined cycle operation (NortheastCHP, 2010a).



1. Inlet Section
2. Compressor
3. Combustion System
4. Turbine
5. Exhaust System
6. Exhaust Diffuser

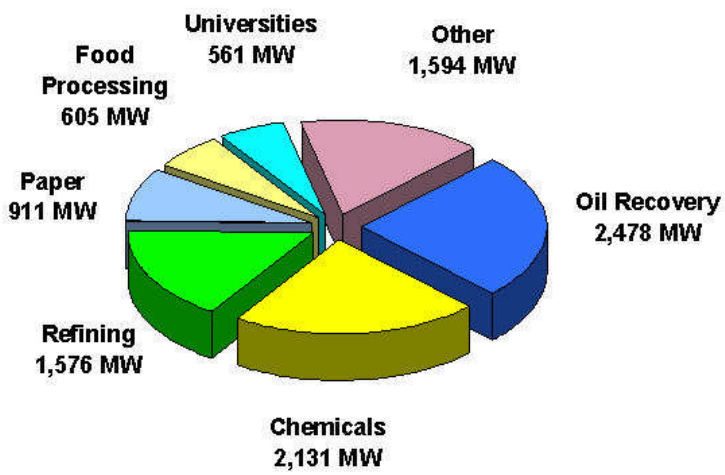
Courtesy of siemens Westinghouse

Gas turbines are available ranging in size from 500 kilowatts (kW) to 250 megawatts (MW) and can utilize a variety of fuels such as natural gas, synthetic gas, landfill gas, and fuel oils (US EPA, 2008). Simple cycle gas turbines are available with efficiencies reaching 40% Lower Heating Value (LHV); however gas turbines used in the CHP configurations can achieve overall system efficiencies, including both electric and useful thermal energy, of 70-80% LHV (NortheastCHP, 2010a). Gas turbines in CHP models have been used successfully nationwide in many industrial and institutional facilities to generate power and thermal energy. There are several examples of CHP technology in Maine, including Eastern Maine Medical Center, which is an example of a medium-sized (5,000 kW) CHP combustion turbine/generator system and will be discussed in Section 3, and Verso Paper Jay Mill Cogeneration System, an example of a large-size combustion turbine (50,000 kW each).

Compared to any other fossil technology in general commercial use, gas turbines emit substantially less carbon dioxide (CO_2) per Kilowatt-hour (kWh) generated because of their high efficiency and reliance on natural gas as the primary fuel (NortheastCHP, 2010a).

Gas turbine based CHP systems are used in a variety of different applications in the United States, including oil recovery, chemicals, refining, large hospitals, large universities, pharmaceuticals and the paper industry to name a few. Figure 2.4 below shows the distribution of an estimated 359 industrial and institutional facilities operating in the United States in 2000.

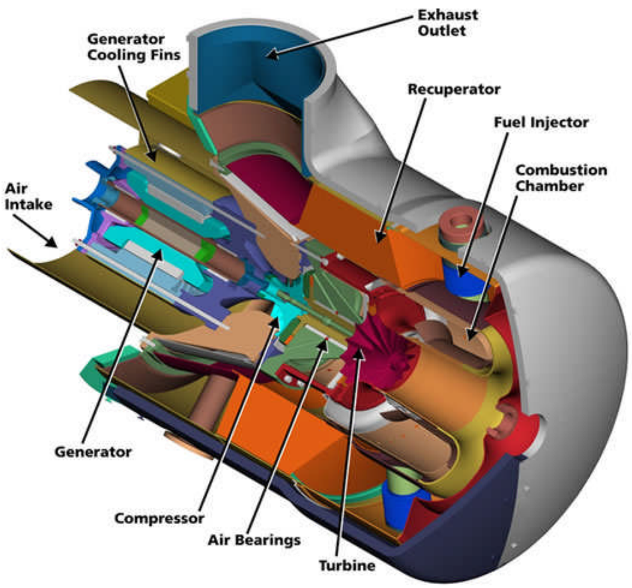
Figure 2-4: Existing Simple Cycle Gas Turbine CHP – 9,854 MW at 359 Sites



Source: www.energysolutionscenter.org

2.1.2 Micro-Turbines with Heat Recovery

Micro-turbines are a type of combustion turbine that produces both heat and electricity on a relatively small scale. The micro-turbine technology was pursued by the automotive industry beginning in the 1950's, entered CHP field testing approximately in 1997, and began initial commercial service in 2000 (NortheastCHP, 2010a). Micro-turbines are small electricity generators that burn gaseous fuels including natural gas, sour gases (high sulfur, low Btu content) and liquid fuels such as gasoline, kerosene, and diesel fuel/distillate heating oil/bio-fuels, to create a high-speed rotation that turns an electrical generator to produce electricity (US EPA, Dec. 2008). Micro-turbines can also burn waste gases that would otherwise be emitted directly into the atmosphere and have extremely low emissions.



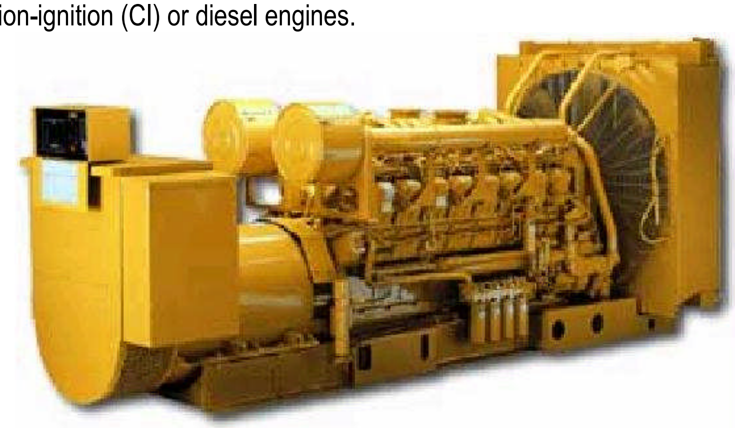
Source: http://www.greenprophet.com/

Most micro-turbines are comprised of a compressor, combustor, turbine, alternator, recuperator (a device that captures waste heat to improve the efficiency of the compressor stage), generator, and heat exchanger. Micro-turbines are available in sizes ranging from 30kW to 350kW (NortheastCHP, 2010a).

They can be used in power-only generation or CHP systems. In CHP operation, a heat exchanger, also known as the exhaust gas heat exchanger, "transfers thermal energy from the micro-turbine exhaust to a hot water system" (US EPA, 2008). The exhaust heat can also be used for space heating, process heating, absorption chillers, desiccant dehumidification equipment, and other building uses. Heat Recovery Steam Generators are now also readily used with micro-turbines for CHP steam applications (Cain, undated).

2.1.3 Reciprocating Engines with Heat Recovery

Reciprocating engines are a well known and widespread technology developed more than 100 years ago. They were the first of the fossil fuel-driven distributed generation technologies. Reciprocating engines are a subset of internal combustion engines, which also include rotary engines. They are machines in which pistons move back and forth in cylinders. There are two common types of reciprocating engines used in CHP systems: spark-ignition (SI) gas engines and compression-ignition (CI) or diesel engines.



Source: http://www.energysolutionscenter.org

SI gas engines use "spark plugs with a high-intensity spark of timed duration to ignite a compressed fuel-air mixture within the cylinder" (US EPA, 2008). The preferred fuel in electric generation is natural gas; however they can also run on gasoline, propane, bio-gas and landfill gas. For power generation, SI engines range in size from a few kW to over 5 MW.

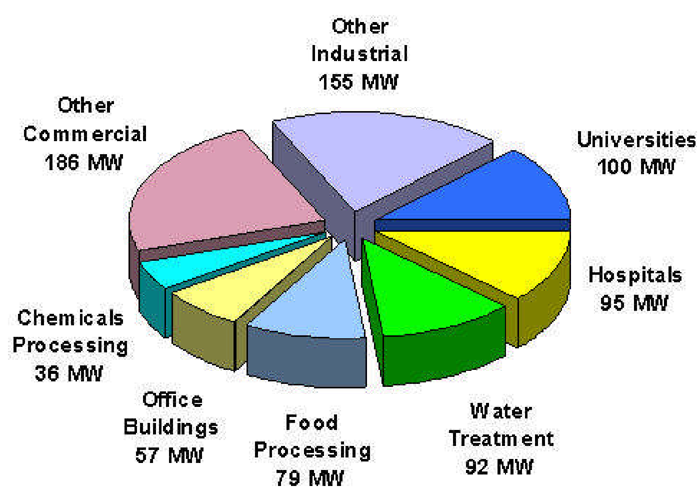
CI engines, otherwise referred to as diesel engines, run on diesel fuel or heavy oil or bio-fuels. They can also be set-up as dual fuel engines to run on primarily natural gas with small amounts of diesel pilot fuel (US EPA, 2008).

Reciprocating engines start quickly, have excellent load-following characteristics, have high reliabilities when maintained properly, and have significant heat recovery potential. They are well suited for applications that require low-pressure steam or hot water, and many times multiple reciprocating engine units are utilized in the CHP model to enhance the capacity and availability of the facility.

The electric efficiency of natural gas engines ranges from 28% LHV for smaller engines (<100 kW) to over 40% LHV for large lean-burning engines (>3 MW) (NortheastCHP, 2010a). For CHP applications, hot water or low pressure steam is produced from the waste heat recovered from the hot engine exhaust and from the engine cooling systems. As a result, the natural gas engines in CHP systems commonly have an overall efficiency of 70-80%, which includes both electricity and useful thermal energy (NortheastCHP, 2010a).

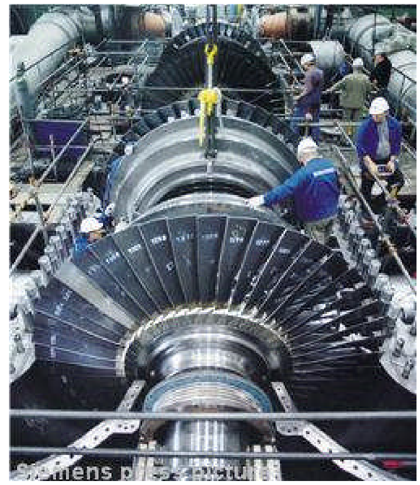
Reciprocating engine CHP systems are used in a variety of different applications in the United States, including chemical processing, food processing, universities, and hospitals to name a few. Figure 2-5 below shows the distribution of an estimated 1,055 engine based CHP systems operating in the United States in 2000.

Figure 2-5: Existing Reciprocating Engine CHP - 801 MW at 1,055 Sites



Source: www.energysolutionscenter.org

2.1.4 Steam Boilers with Steam Turbine Generators (CHP Model 2)



One of the most versatile and oldest prime mover technologies used to run a generator or mechanical system is a steam turbine. Most of the electricity produced in the United States is generated by conventional steam turbine power plants. The capacity of steam turbines ranges in size from 50 kW to more than 1,300 MW for larger utility power plants.

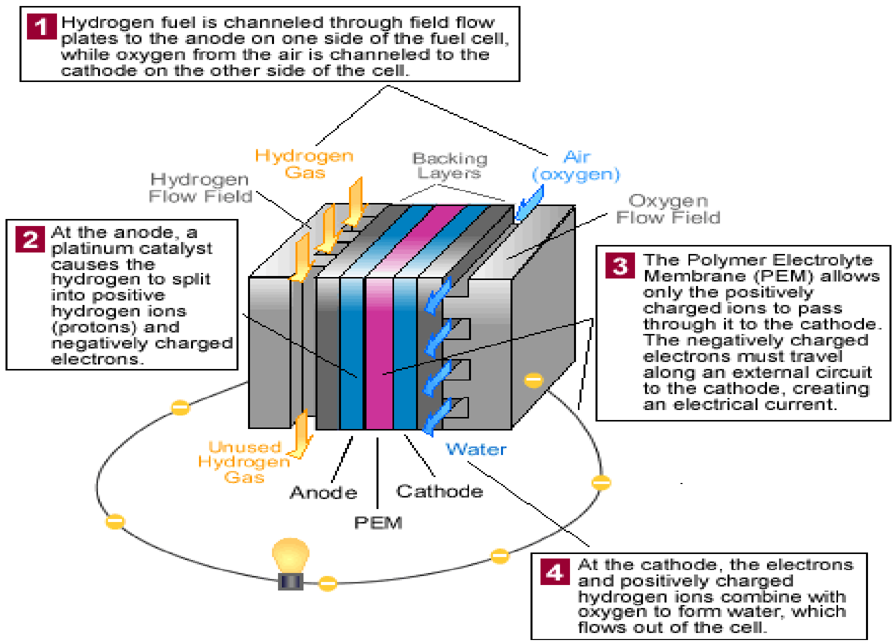
Steam turbines are unlike gas turbines and reciprocating engines because they produce electricity as a byproduct of heat (steam) generation. Steam turbines do not directly convert fuel to electrical energy; instead the energy is transferred from the boiler to the turbine through high-pressure steam that in turn powers the turbine and generator (NortheastCHP, 2010a). Steam boilers for steam turbines operate with a variety of different fuels, ranging from natural gas to solid waste, including all types of wood, wood waste, coal, and agricultural byproducts such as fruit pits, sugar cane bagasse, and rice hulls.

Steam turbines are well suited for CHP applications. In CHP systems, steam is extracted from the steam turbine after electrical generation at lower pressure and used directly or converted to other forms of thermal energy. To match the preferred application and/or performance specifications for either utility or industrial applications, steam turbines are available in a wide variety of designs and complexity. Steam turbines can be specified as full condensing type, extraction type and back-pressure type. Each of these configurations is dependent on the CHP application and the overall energy balance for both thermal and electrical energy at the host site.

2.1.5 Fuel Cells with Heat Recovery

Fuel cell systems produce energy differently than traditional prime mover technology – they produce electricity and heat without combustion or moving parts. Instead, they use an electrochemical process to convert the chemical energy of hydrogen and oxygen into electricity and heat.

Figure 2-6: Fuel Cell System



Source: www.nersc.gov

Fuel cells consist of two electrodes, an anode and a cathode, separated by an electrolyte. See Figure 2-6 above. Electrochemically, power is produced when charged particles, ions, formed at one end of the electrodes pass through the electrolyte with the aid of catalysts (NortheastCHP, 2010a). The produced current can be used for electricity.

Fuel cells use hydrogen as their fuel, which can be derived from natural gas, coal gas, methanol, and other hydrocarbon fuels. There are five types of fuel cells under development, and they include:

1. Phosphoric Acid (PAFC);
2. Proton Exchange Membrane (PEMFC);
3. Molten Carbonate (MCFC);
4. Solid Oxide (SOFC); and
5. Alkaline (AFC).

The electrolyte and operating temperature distinguish each type of fuel cell; however each fuel cell system is composed of three primary subsystems: (1) the fuel cell stack that generates direct current electricity, (2) the fuel processor that converts the natural gas into a hydrogen-rich feed stream, and (3) the power conditioner that processes the electric energy into alternating current or regulated direct current. All types of fuel cells have low emissions due to the burning of low energy hydrogen exhaust stream that is used to provide heat to the fuel processor (US EPA, 2008).

Fuel Cell Application: Sierra Nevada Brewing

Sierra Nevada recently completed one of the largest fuel cell installations in the United States: they installed four 250-kilowatt co-generation fuel cell power units to supply electric power and heat to the brewery. Natural gas or bio-gas is fed to the fuel cell, where hydrogen gas is extracted and combined with oxygen from the air to produce electricity, heat, and water. Their one megawatt of power output will produce most of the brewery's electrical demand, and the co-generation boilers will harvest the waste heat and produce steam for boiling the beer and other heating needs. Fuel cells are efficient, quiet, and produce extremely low emissions. The overall energy efficiency of the installation is double that of grid-supplied power and air emissions are significantly reduced. Surplus electrical energy will be sold back into the power grid.

Sierra Nevada's commitment to energy efficiency and reducing the company's environmental impact led them to look at many alternatives for their energy needs. The fuel cell was one of the cutting-edge new technologies they chose to embrace that has exciting potential for meeting the United States' future energy needs. Sierra Nevada's decision was based on dramatically lower emissions than conventional power generation, minimal electrical line transmission loss, and their ability to co-generate and use the waste heat from the fuel cell in their brewing process, for further information see Appendix C.

2.1.6 Comparison of CHP Configurations

There are several factors to consider when comparing CHP technologies, including installed costs, operation and maintenance (O&M) costs, start-up time, availability, thermal output, efficiency, and emissions (US EPA, 2008). Table 2-1 compares the different CHP technologies by listing key performance characteristics and cost information.

Table 2-2: Summary of CHP Technologies

CHP system	Advantages	Disadvantages	Available sizes
Gas turbine with heat recovery	• High reliability. • Low emissions. • High grade heat available. • No cooling required.	• Require high pressure gas or in-house gas compressor. • Poor efficiency at low loading. • Output falls as ambient temperature rises.	500 kW to 250 MW
Micro-turbine with heat recovery	• Small number of moving parts. • Compact size and light weight. • Low emissions. • No cooling required.	• High costs. • Relatively low mechanical efficiency. • Limited to lower temperature cogeneration applications (low pressure steam and hot water)	30 kW to 250 kW
SI reciprocating engine with heat recovery	• High power efficiency with part-load operational flexibility. • Fast start-up. • Relatively low investment cost. • Can be used in island mode and have good load-following capability. • Can be overhauled on site with normal operators. • Operate on low-pressure gas. • Can be configured in multiple models.	• High maintenance costs. • Limited to lower temperature cogeneration applications. • Relatively high air emissions. • Must be cooled even if recovered heat is not used. • High levels of low frequency noise.	< 5 MW in DG applications
CI reciprocating engine (dual fuel pilot ignition) with heat recovery			High speed (1,200 RPM) ≤4MW Low speed (102-514 RPM) 4-75 MW
Steam boilers with steam turbine generators	• High overall efficiency. • Any type of fuel may be used. • Ability to meet more than one site heat grade requirement. • Long working life and high reliability. • Power to heat ratio can be varied.	• Slow start up. • Low power to heat ratio.	50 kW to 250 MW
Fuel cells with heat recovery	• Low emissions and low noise. • High efficiency over load range. • Modular design.	• High costs. • Low durability and power density. • Fuels require processing unless pure hydrogen is used.	5 kW to 2 MW

Source: US EPA, Catalog of CHP Technology, Dec. 2008

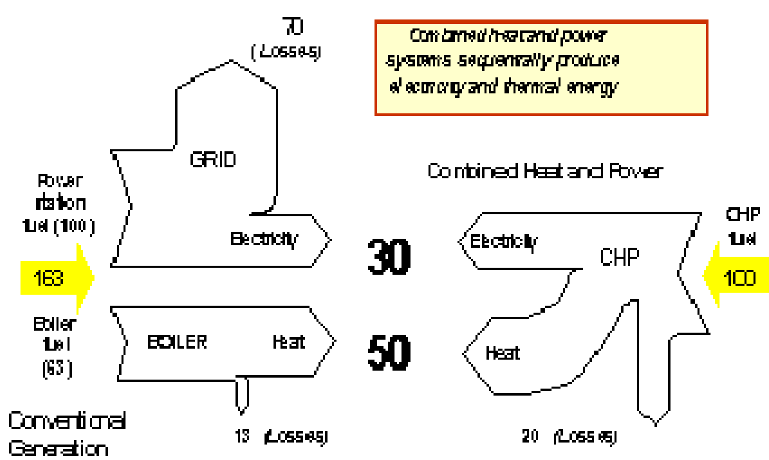
2.2 BENEFITS OF CHP

Cogeneration benefits include increased energy efficiency, decreased operating costs, improved environmental quality and economic development opportunity (US EPA, 2010b). For industrial facilities, there are additional benefits such as increased reliability, power quality, and higher productivity (ESC, 2004). For deregulated areas, host CHP sites can bilaterally distribute excess electricity to other business units within the deregulated territory providing low cost electricity supply to other non-CHP business sites.

Efficiency Benefits

Integrated CHP systems increase efficiency of energy utilization to as much as 85% from 51% for conventional power generation systems (NortheastCHP, 2010c). Conventional systems require 65% more energy than integrated CHP systems. Using CHP systems can reduce the consumption of fossil fuels (for a unit of energy needed) by about 40% compared to conventional systems. This is a key factor in reducing our dependence on imported fuels.

Figure 2-7: Example of CHP Energy Savings



Source: www.energysolutionscenter.org

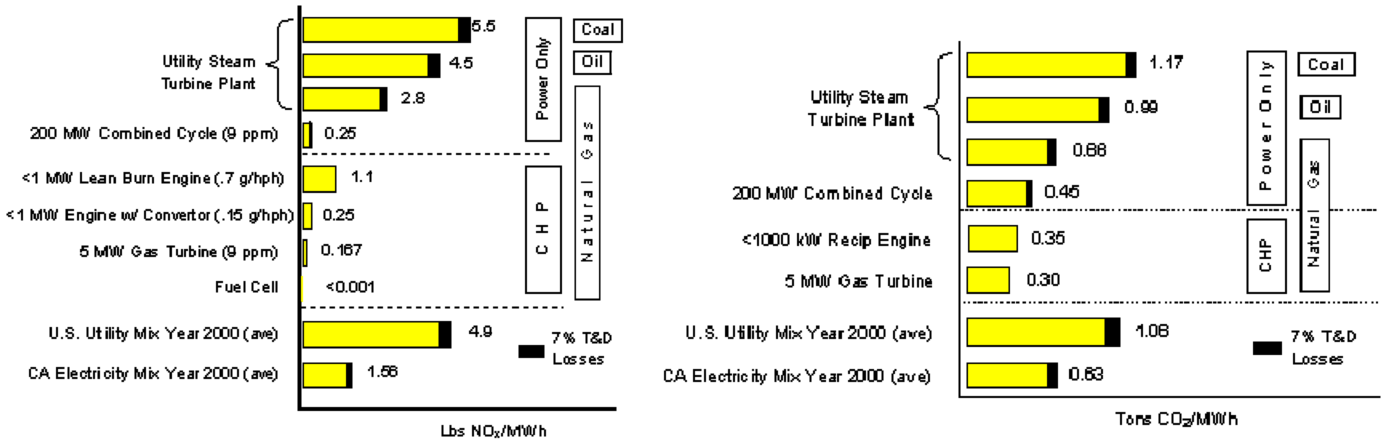
Figure 2-7 above demonstrates the energy savings. For 100 units of input fuel, CHP converts 80 units to useful energy of which 30 units are electricity and 50 units are for steam or hot water. However, traditional separate heat and power components require 163 units of energy to accomplish the same end use tasks (ESC, 2004).

Environmental Benefits

CHP reduces less air pollution and greenhouse gas emissions because less fuel is burned to produce each unit of energy output. By increasing energy efficiency, CHP also reduces emissions of criteria pollutants such as nitrogen oxides (NOx) and sulfur dioxide (SO_2) and non-criteria greenhouse gases such as CO_2. For CHP systems that utilize renewable fuel sources, the environmental benefits are even greater than using fossil fuels for the CHP energy model. For example, sustainably harvested biomass-fueled CHP systems are being defined as a net zero carbon emissions model.

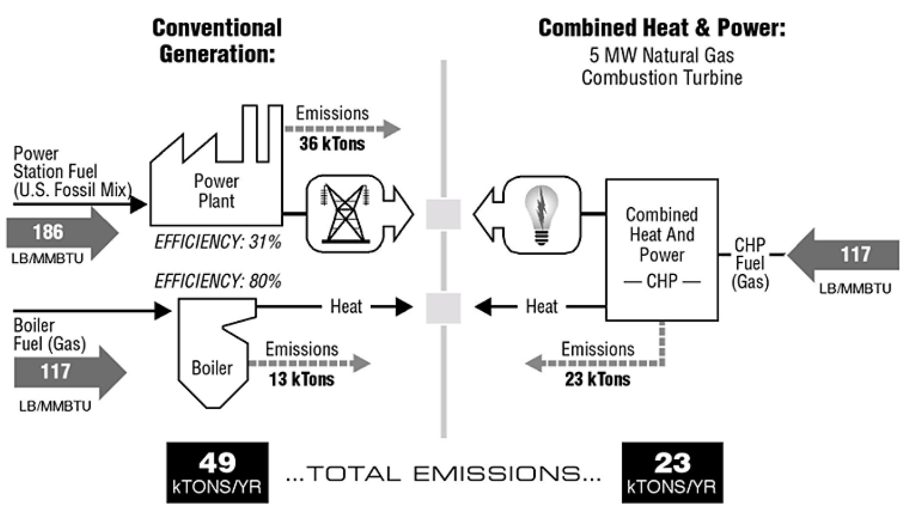
Figure 2-8 below shows NOx and CO_2 emission comparisons, respectively, by power generation technology and fuel type conducted in 2000. For reference, nationwide and California utility emissions are also shown.

Figure 2-8: NOx and CO_2 Reduction Benefits of CHP



Source: USCHPA, DOE, CEC, AGA, Onsite Energy

Figure 2-9: CO_2 Emission Output

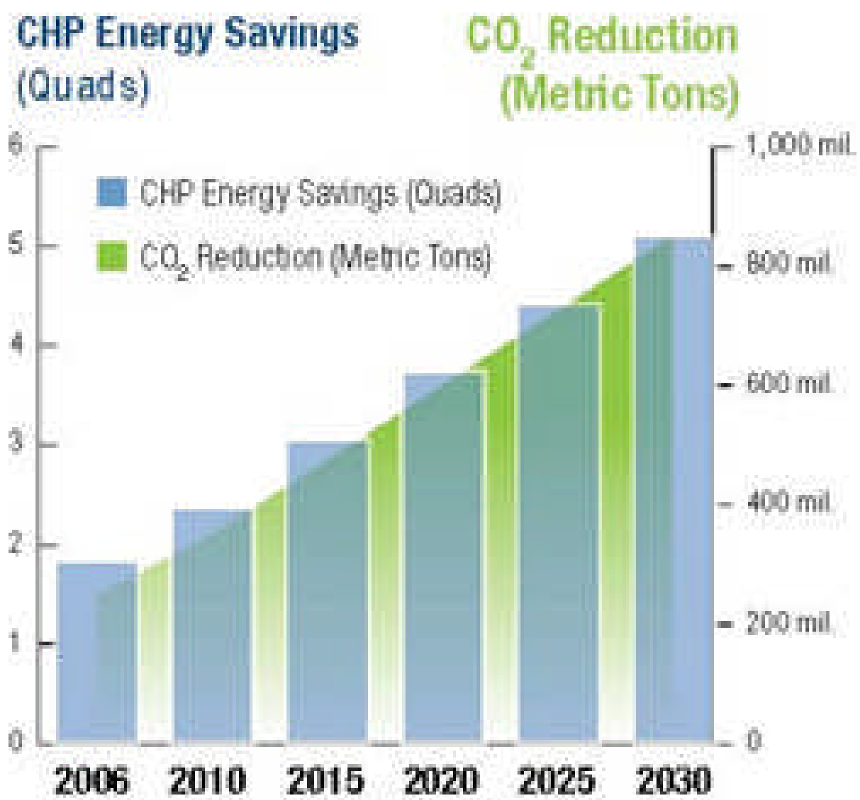


Source: http://www.epa.gov/chp/basic/environmental.html

Figure 2-9 above shows the CO_2 emissions output from power and thermal energy generation for a conventional separate heat and power system with a fossil fuel-fired power plant and a natural gas-fired boiler and a CHP system (5 megawatt combustion-turbine) powered by natural gas. The CHP system emits a total of 23,000 tons of CO_2 per year compared to more than twice the CO_2 emissions per year (49,000 tons per year) for the conventional system.

Currently in the United Sates, there are approximately 3,500 CHP systems with a generating capacity of 85 GW, which avoids more than 1.9 quadrillion Btu of fuel consumption and reduces 248 metric tons of CO_2 emissions. This is equivalent to removing more than 45 million cars from the road (EERE, 2009). In helping the United States achieve its goal of 20% of CHP power generation by 2030, there is the potential to save approximately 5.8 quadrillion Btu per year, 240 GW (equal to 200-300 coal-fire power plants), and 848 million metric tons of CO_2 emissions. See Figure 2-10 below. This is equivalent to removing more than 150 million cars off the road (EERE, 2009).

Figure 2-10: Potential Savings of 20% of CHP Generation Capacity by 2030



Source: http://www1.eere.energy.gov/industry/bestpractices/energymatters/archives/winter2009.html

As demonstrated here, CHP can significantly reduce emissions, thereby reducing Maine's carbon footprint and boosting environmental benefits. Summarized below are the emissions results using the US EPA CHP Partnership emissions calculator for small and large natural gas CHP systems.

Small CHP System (Tri-Generation) Emissions Summary (See Appendix D):

The small system is comprised of a 150 kW micro-engine generator, heat recovery system and absorption chiller to provide electricity, heating and cooling for a municipal facility in Maine. The basic emissions metrics are as follows:

Self-Gen, Inc.
Scarborough, Maine

Town Hall - Tri-Generation
Basic Emmissions Data

CHP Results

The results generated by the CHP Emissions Calculator are intended for eductional and outreach purposes only; it is not designed for use in developing emission inventories or preparing air permit applications.

Annual Emissions Analysis

	CHP System	Displaced Electricity Production	Displaced Thermal Production	Emissions/Fuel Reduction	Percent Reduction
NOx (tons/year)	0.19	0.55	0.24	0.60	76%
SO2 (tons/year)	0.00	1.08	0.00	1.07	100%
CO2 (tons/year)	733	1,041	282	590	45%
Carbon (metric tons/year)	181	257	70	146	45%
Fuel Consumption (MMBtu/year)	12,562	17,459	4,828	9,725	44%
Acres of Forest Equivalent				122	
Number of Cars Removed				97	

This CHP project will reduce emissions of Carbon Dioxide (CO2) by 590 tons per year

This is equal to 146 metric tons of carbon equivalent (MTCE) per year

This reduction is equal to removing the carbon that would be absorbed by 122 acres of forest

OR

This reduction is equal to removing the carbon emissions of 97 cars

chp_emissions_calc, Results   Page 1 of 5   3/6/2010

Large CHP System (Tri-Generation) Emissions Summary (See Appendix D):

The large system is comprised of a 4.6 MW combustion-turbine generator, heat recovery steam generator/boiler (HRSG) and absorption chiller to provide electricity, heating and cooling for a large medical facility. The basic emissions metrics are as follows:

Large-Tri-Gen-NG Model
Emissions Metrics

Combine Metrics with attached
Combined-Cycle S/T/G emissions data.

CHP Results

The results generated by the CHP Emissions Calculator are intended for eductional and outreach purposes only; it is not designed for use in developing emission inventories or preparing air permit applications.

Annual Emissions Analysis	CHP System	Displaced Electricity Production	Displaced Thermal Production	Emissions/Fuel Reduction	Percent Reduction
NOx (tons/year)	52.33	16.25	22.45	(13.63)	-35%
SO2 (tons/year)	0.19	31.73	23.55	55.10	100%
CO2 (tons/year)	36,644	30,700	24,085	18,142	33%
Carbon (metric tons/year)	9,060	7,591	5,955	4,486	33%
Fuel Consumption (MMBtu/year)	627,996	514,877	299,382	186,264	23%
Acres of Forest Equivalent				3,738	
Number of Cars Removed				2,996	

This CHP project will reduce emissions of Carbon Dioxide (CO2) by 18,142 tons per year

This is equal to 4,486 metric tons of carbon equivalent (MTCE) per year

This reduction is equal to removing the carbon that would be absorbed by 3,738 acres of forest

OR

This reduction is equal to removing the carbon emissions of 2,996 cars

Emmissions-Example-Large-Tri-Gen-NG, Results   Page 1 of 5   3/8/2010

Economic Benefits

CHP can offer a variety of economic benefits. The use of CHP will save facilities considerable money in reduced energy costs which is a direct result of the increased energy efficiency of CHP systems. Additionally, CHP systems can produce power at rates that are lower than the utility's delivered price; the cost of such power of course varies and is dependent on application, technology, and grid circumstances (ESC, 2004). There are also no utility transmission and distribution losses.

Small CHP System (Tri-Generation) Economic Benefits Summary (See Appendix D):

The small system is comprised of a 150 kW micro-engine generator and heat recovery system and absorption chiller to provide electricity, heating and cooling for a municipal facility in Maine. The basic economic metrics are as follows:

Energy Category	*Existing Energy "Debits"*	*Tri-Gen Energy "Debits"*	*Tri-gen Energy "Credits"*	
Existing Building Usage - Thermal 1:	-$24,957.00	-$122,289.71		
Excess Energy Required/Saved - Thermal 2:		$0.00	$0.00	*Excess Thermal 'sold'*
Chiller Electrical Savings - Thermal 3:			$30,120.65	*Electric Chiller Savings (accounts for differentials in kWh $)*
Town Hall Total - Electric:	**-$66,169.00**	$0.00	$116,496.35	*Excess Electricity Net Metered with Other Municipal Meters (10)*
Totals – 2006 - 2007:	**-$91,126.00**	**-$122,289.71**	**$146,617.00**	
Maintenance Cost / Year plus Escrow:			-$10,442.29	
Energy Difference Adjustment "+" or "-":			-$31,163.71	
TOTAL SAVINGS PER YEAR:			**$105,011.00**	
Estimated Project Cost - "1" - 150 kW Engine:			**$498,629.40**	
	4.75	**Year Payback**	***$49,863***	10% Grant
w/ 10% grant	**4.27**	**Year Payback**	***$448,766.46***	
w/ $200/kW credit	**4.62**	**Year Payback**	***$485,629.40***	

Large CHP System (Tri-Generation) Economic Benefits Summary (See Appendix D – 11"x 17" Calcs.):

The large system is comprised of a 4.6 MW combustion-turbine generator, heat recovery steam generator/boiler (HRSG) and absorption chiller to provide electricity, heating and cooling for a large medical facility. The basic economic metrics are as follows:

Simple Payback Summary for Large Tri-Generation Systems (CHP):

$ 2,361,068 – Electricity Savings with Tri-gen (CHP)
$ 500,492 – Thermal Savings with Tri-gen (CHP)
$ 2,861,560

$ 9,000,000 ÷ $ 2,861,560 **= 3.14 Year Simple Payback**

(including Utility (Transmission and Distribution) T&D Fees of $ 525,000 or 100% of current T&D costs)

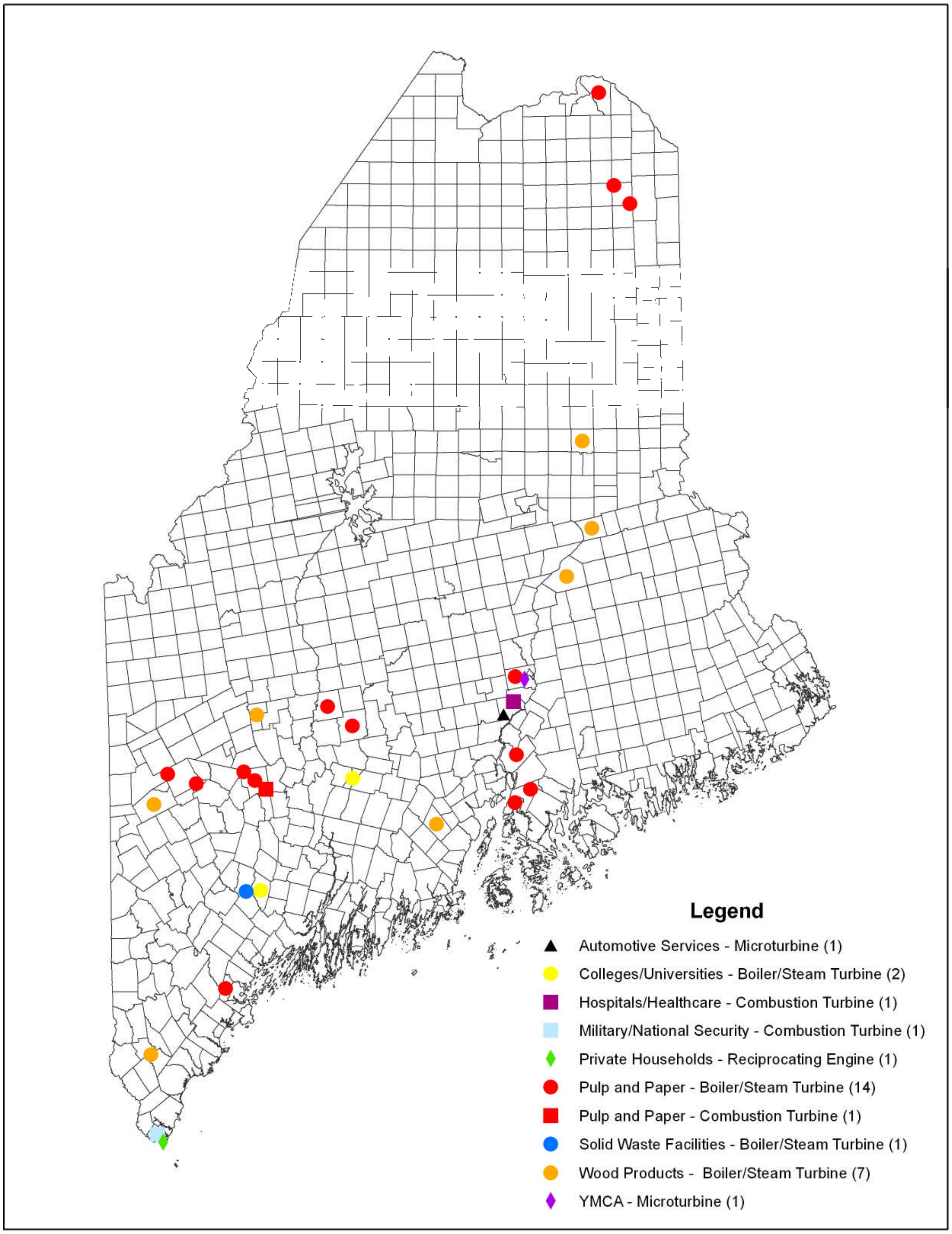
2.3 CHP IN VARIOUS FACILITY TYPES

CHP technology is used nationwide in a wide variety of energy-intensive facility types and sizes (US EPA, 2010b) including:

- Industrial manufacturers: pharmaceutical, chemical, refining, bio-fuels production, pulp and paper, sawmills, wood product manufacturers, food processing, and glass manufacturing;

- Institutions: colleges and universities, hospitals, prisons, and military bases;
- Commercial buildings: hotels and casinos, airports, high-tech campuses, large office buildings, and nursing homes;
- Municipal: district energy systems, wastewater treatment facilities, and K-12 schools; and
- Residential:multi-family housing and planned communities.

In Maine there are 24 boiler/steam turbines, three combustion turbines, two micro-turbine, and one reciprocating engine (Appendix E). These 30 CHP facilities with a total capacity of 1,130,880 kW, are in the following applications/industries: pulp and paper (15), wood products (7), colleges and universities (2), automotive services, health care, military, solid waste, one private household and one YMCA (EEA, 2009). See map below.



Source of current CHP facilities in Maine: http://www.eea-inc.com/chpdata/states/me.html, map provided by Woodard & Curran

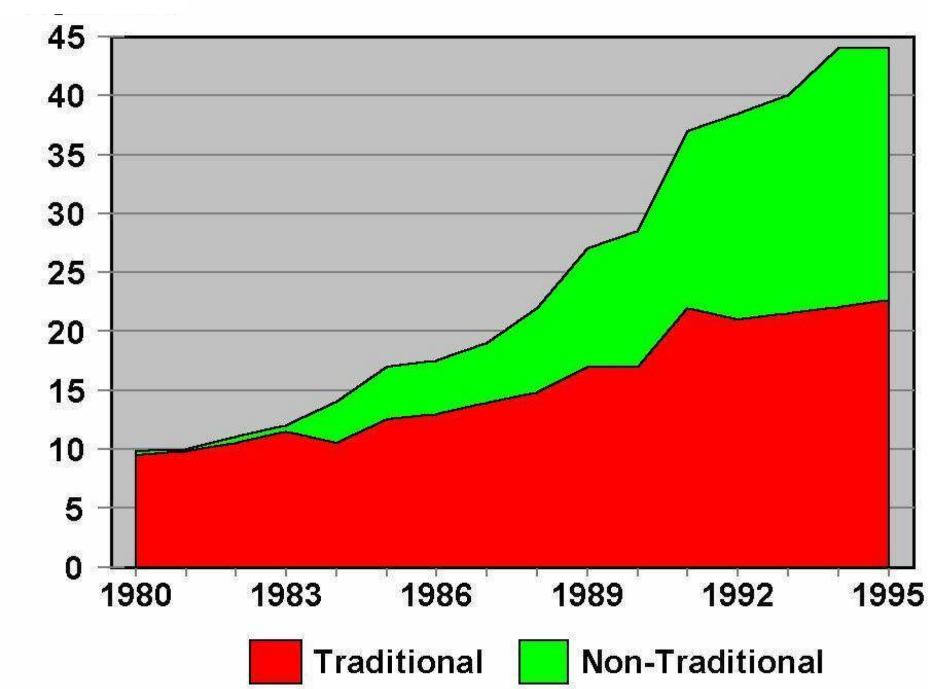
3. CHP BACKGROUND AND RESOURCES

3.1 PUBLIC UTILITIES REGULATORY POLICY ACT

In 1978 the US Congress passed the Public Utilities Regulatory Policy Act (PURPA) requiring electric utilities to interconnect with CHP and small renewable power sources and buy electricity from these sources at their avoided costs. This encouraged many large industrial customers to install CHP, interconnect to the utility grid, and sell power to the local utility. Since PURPA provided the only way for non-utility generators to sell excess electricity, many independent power producers found a use for some of their waste thermal energy. This allowed them to qualify as cogenerators under PURPA. These electricity-optimized CHP systems are called "non-traditional" cogenerators. (ACEEE, 2010).

During the 1980s there was a rapid growth of CHP capacity in the United States: installed capacity increased from less than 10 gigawatts electric (GWe) in 1980 to almost 44 GWe by 1993 (see Figure 3-1).

Figure 3-1: CHP Capacity in US from 1980 - 1995

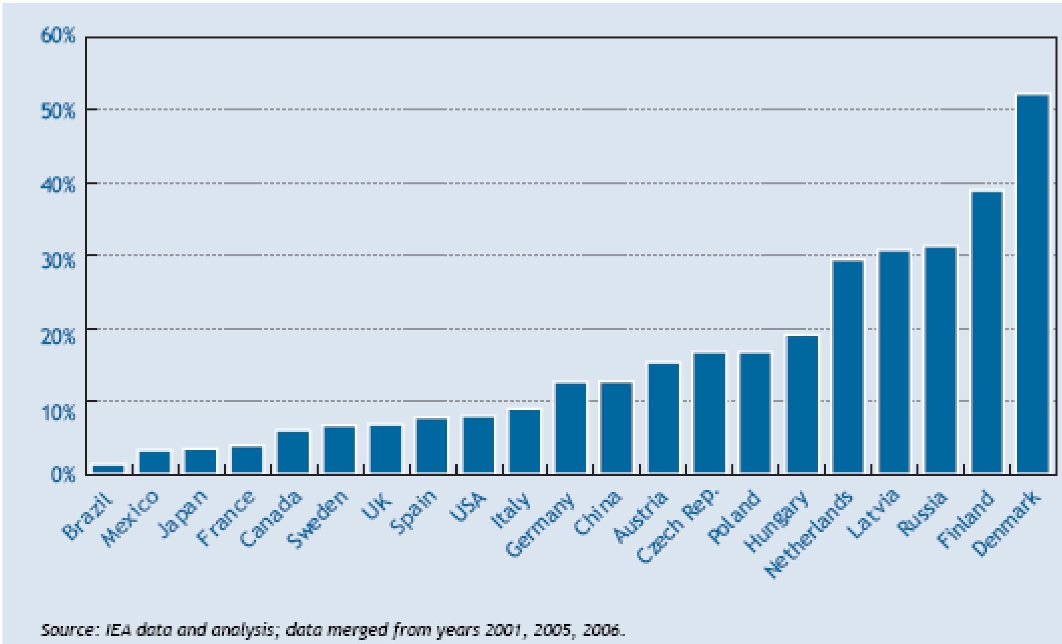


Source: www.aceee.org

Most of this capacity was installed at large industrial facilities such as pulp and paper, petroleum, and petrochemical plants, which provided a "thermal host" for the electric generator (ACEEE, 2010).

PURPA no longer provides sufficient incentive to install CHP. Nevertheless, it paved the way for an increased number of CHP facilities in the United States in addition to the pre-existing localized district heating systems that already existed in various cities like New York City, Boston, MA, Concord, NH and a number of older military bases. Currently, about 10% of total US electrical generation comes from CHP (see Figure 3-2).

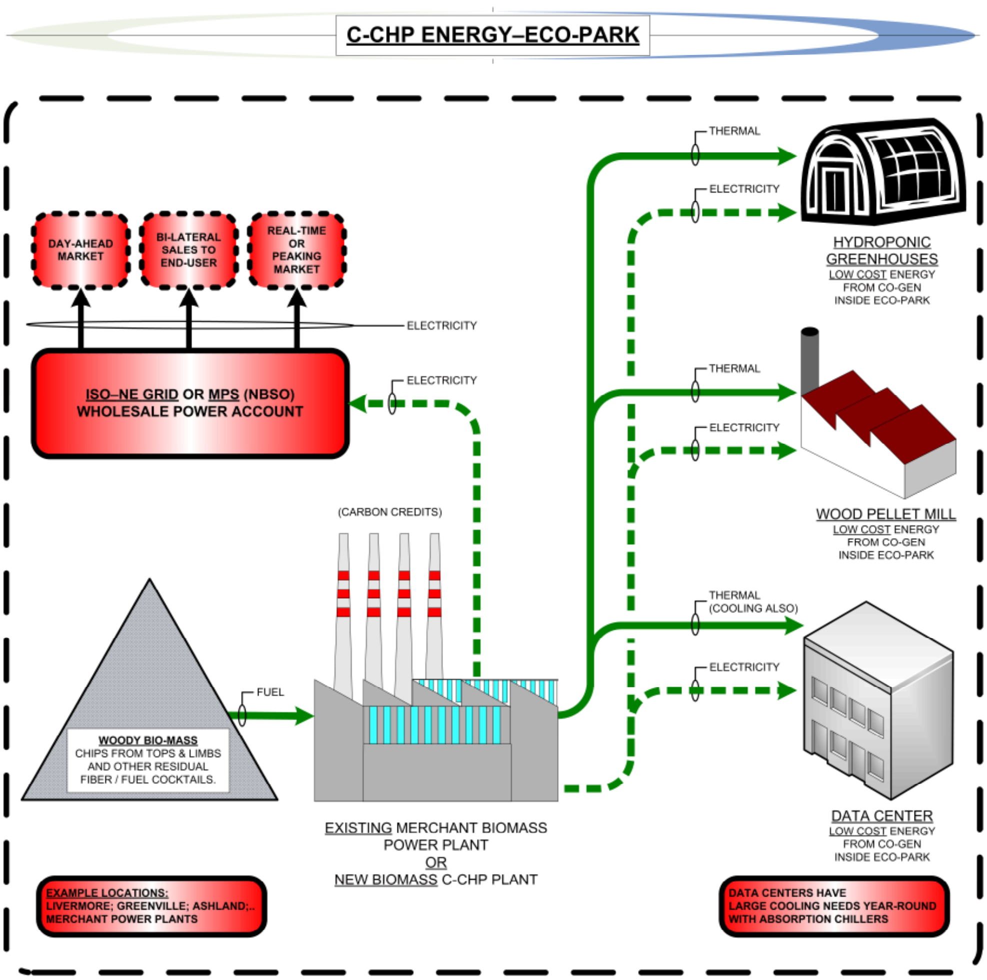
Figure 3-2: CHP as a Share of Electricity Generation



Denmark, Finland, Russia, and Latvia have expanded use of CHP between 30-50% of total power generation (IEA, 2009) and each took a different approach. One factor is common among the countries that have successfully implemented CHP, namely a focused government policy on electricity and heat supply (IEA, 2009). In Switzerland cogeneration accounts for about 77% of their total electricity production (BPE, 2010), of that, 56% is produced from hydropower and 40% is produced from nuclear power. As a consequence, Switzerland has almost CO_2-free electricity production.

Europe has been employing a district heating model for over thirty years. Switzerland uses "organic fuel pellets" for their power plants from the "organic" content of municipal solid waste (MSW) that is cleanly processed for all recyclable content with the remaining content being "organic." The recycled content is sold for value-added uses and the organic content is pelletized for the clean fuel at power plants sited for district heating using CHP. Oceanside Rubbish is proposing the same model for the York/Wells area and MERC is proposing a hybrid model for their Saco plant, but the sorting and fuel pelletizing will be done remotely instead of downtown.

Existing free-standing power plants and proposed future merchant power plants should be encouraged to explore CHP using their low-value waste thermal energy (i.e. Calpine in Westbrook providing thermal energy to IDEXX Labs (heating and cooling) and low cost electricity using the ECO Park Model – see graphic below).



Source: Self-Gen, Inc.

3.2 UNITED STATES CLEAN HEAT & POWER ASSOCIATION

The United States Clean Heat and Power Association (USCHPA) is a private non-profit trade association that was formed in 1999. At that time, USCHPA promoted combined heat and power and sought out public policy support for CHP, but in 2007 it expanded its focus. USCHPA continued its full support for CHP and also began advocating for recycled energy, bio-energy, and other local generation sources, all focused on reducing greenhouse gas emissions (USCHPA, 2010). The association consists of more than 60 organizations and their affiliates (including several Fortune 500 companies), 300 individuals, and allied industry groups. It sponsors workshops, advocacy events, and conferences to educate the public about clean heat and power. USCHPA is committed to the CHP program of the DOE and the US Environmental Protection Agency (US EPA) CHP Partnership, and is working to achieve a cleaner, more affordable, and more reliable national energy system (USCHPA, 2010).

3.3 US EPA CHP PARTNERSHIP

In 2001, US EPA formed the CHP Partnership, a voluntary program with the main goal of reducing the environmental impact of power generation by encouraging the installation and use of CHP. The Partnership works closely with entities such as energy users, the CHP industry, state and local governments, and other clean energy stakeholders to support and assist new cost-effective CHP projects and promote the economic and environmental benefits of cogeneration. Through 2007, the CHP Partnership helped install more than 335 CHP projects, representing an estimated 4,450 MW of capacity. The emissions reductions are equivalent to removing the annual emissions of more than two million automobiles or planting more than 2.4 million acres of forest. Using CHP technology equates to approximately 25% reduction of emissions (US EPA, 2010a)

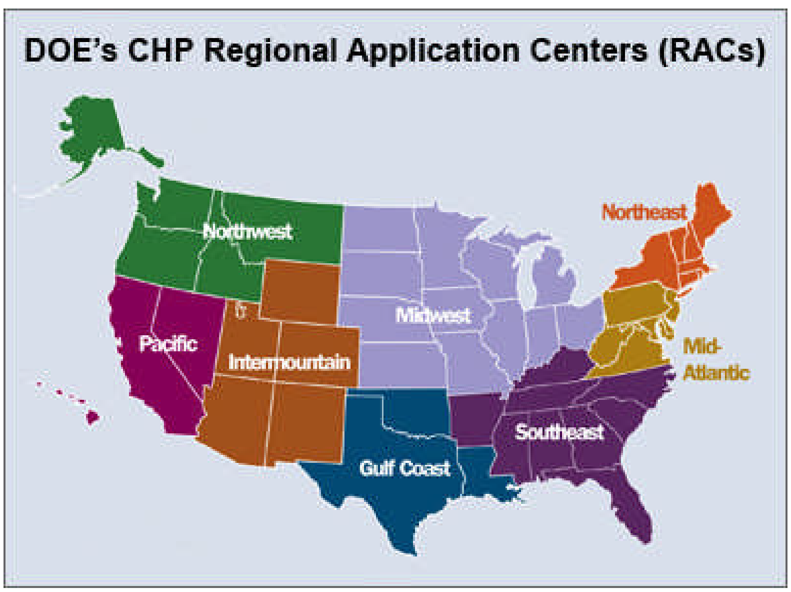
3.4 NORTHEAST CHP INITIATIVE

The Northeast Combined Heat and Power Initiative (NECHPI), a group of state and federal agencies, organizations and individuals, was established around 2000. This group is committed to promoting the use and implementation of CHP in the Northeast. Their mission is to encourage the use of CHP, support DOE's and US EPA's goal of doubling the CHP-produced power from 46GW to 92GW by 2010, and to be a communication and coordination central point for various CHP stakeholders in the Northeast, including state and federal agencies, utilities, project developers, CHP users, universities, research institutions, equipment manufacturers, and public interest groups (NECHPI, 2010).

3.5 NORTHEAST CHP REGIONAL APPLICATION CENTER

DOE formed the Northeast CHP Regional Application Center (NECHPRAC) at the University of Massachusetts Amherst (UMass) and Pace University (Pace) in October of 2003. The NECHPRAC is one of eight Regional Application Centers in the United States (see Figure 3-3).

Figure 3-3 CHP Regional Application Centers



Source: www.eere.energy.gov

NECHPRAC encourages the development and implementation of CHP systems, and it also provides consulting services for CHP in the seven Northeast states of Connecticut, Maine, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. Additionally, NECHPRAC can address many technical and policy issues for industry, commercial and institutional energy end-users (NortheastCHP, 2010b).

3.6 MAINE COMPREHENSIVE ENERGY ACTION PLAN

The Maine Comprehensive Energy Action Plan recognizes and addresses CHP in the *Fostering Renewable Energy* section. The Plan calls for identifying, assessing and removing technical, regulatory, policy and economic barriers to the use of cogeneration or tri-generation facilities. Additionally, increasing the development and use of cogeneration and tri-generation is specifically listed as a goal to achieve improvements in fostering renewable energy (OEIS, 2009).

3.7 NET METERING AND NET ENERGY BILLING

Net metering enables electricity customers to use their own generation to offset their consumption. This flexibility allows customers to maximize the value of their production by either being paid for excess power supplied to the grid or "banking" their energy and carrying the surplus over to the next billing period. Providers can benefit through improvement (reduction) of their system's load during peak hours. Net metering provisions have a limited scope as to the size and types of facilities that may be subject to their provisions. As of 2010, 43 states, including Maine, and the District of Columbia have net metering provisions.

In Maine, all utilities must offer net energy billing, a type of net metering, for individual customers. According to MPUC Chapter 313 Rule, "net energy billing" is a "billing and metering practice under which a customer and the shared ownership customers are billed on the basis of net energy over the billing period taking into account accumulated unused kilowatt-hour credits from the previous billing period." Eligible facilities include those with capacity limits up to 660 kilowatts (kW) and include facilities generating electricity using fuel cells, tidal power, solar, geothermal, hydroelectric, biomass, generators fueled by municipal solid waste in conjunction with recycling, and eligible CHP systems. CHP systems must meet efficiency requirements in order to qualify – micro-CHP 30kW and below must achieve combined electrical and thermal efficiency of 80% or greater and micro-CHP 31kW to 660 kW must achieve combined efficiency of 65% or greater. (DSIRE, 2009). This leaves a large intermediate group of systems that have a nameplate capacity greater than the scope of Maine's net metering provisions. There are other MPUC rules that apply to groups above the net metering capacity levels, including Rule 315 for Small Generator Aggregation. Also, deregulation itself allows for excess electricity to be bi-laterally distributed into a wholesale power account of the host for use at other locations owned by the host or for direct sales to ISO-NE grid.

3.8 RGGI TRUST – PROJECTS AND OFFSETS

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by ten Northeast and Mid-Atlantic States to reduce greenhouse gas emissions through a mandatory, market-based CO_2 emissions reduction program. The states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont are signatory states to the RGGI agreement. These ten states have capped CO_2 emissions from the power sector, and will require a 10% reduction in these emissions by 2018. Regulated power plants can use a CO_2 allowance issued by any of the ten participating states to demonstrate compliance with the state program governing their facility. Maine is setting aside allowances to benefit CHP units at integrated manufacturing facilities. Such facilities are allowed to receive free allowances equal to their CO_2 emissions.

3.9 STATE'S RENEWABLE ENERGY PORTFOLIO AND RENEWABLE ENERGY CREDITS

Maine's renewable portfolio standard (RPS) originally required certain electricity providers to supply at least 30% of their total retail electric sales using electricity generated by eligible renewables and energy efficiency resources. In 2007, the Legislature enacted legislation mandating that specified percentages of electricity come from "new" renewable resources, reaching 10% by 2017. Eligible new renewables include those placed into service after September 1, 2005. To qualify, electricity must be generated at either a "Class I" or "Class II" facility. Class I facilities must be no greater than 100 megawatts (MW) in capacity and use fuel cells, tidal power, solar arrays and installations, wind power, geothermal power, hydropower, biomass power or generators fueled by municipal solid waste in conjunction with recycling. Electricity generated by CHP systems that burn an eligible fuel and meet other eligibility criteria may qualify for Class I. In CHP systems, the electric portion of a qualifying CHP project would be eligible (e.g., electricity from a new biomass CHP project at a sawmill would be eligible) while the thermal portion would be ineligible under the renewables goal. As Maine's RPS is reviewed and revised, it has been suggested that the thermal portion of an in-state CHP project should qualify in the RPS and receive renewable energy credit (REC) value in addition to any qualifying generation that is otherwise eligible under the RPS. Massachusetts law currently follows this path and other states are recognizing the value of CHP systems in their RPS requirements. This policy should be fully explored and modeled as appropriate for Maine.

The MPUC has approved the use of NEPOOL Generation Information System (GIS) certificates (which are similar to RECs) to satisfy the portfolio requirement. GIS certificates are awarded based on the number of kilowatt-hours (kWh) of eligible electricity generated. GIS certificates used to meet the Class I standard may not also be used to satisfy the Class II standard. Legislation enacted in June 2009 (L.D. 1075) provides a 1.5 credit multiplier for eligible community-based renewable energy projects.

3.10 DEREGULATION

Under deregulation, Maine utilities (CMP, BHE, MPS) could no longer generate as well as transmit and distribute electricity, so the utilities sold their generation plants and kept their transmission and distribution systems. In March 2000, Maine became a deregulated state which meant the billing for end-users of electricity would be split into supply (generators) and T&D. Deregulation is ideal for CHP applications since excess electricity is easily distributed back to the grid for sale or bilateral distribution to other CHP host facilities and other end-users. Deregulation helped create a model for super-net-metering throughout all of New England (ISO-NE). CHP facilities can now supply all their on-site electrical and thermal energy needs while maximizing the economic benefit of excess electricity by selling it to the grid. For example, the state's east campus has year-round thermal energy needs (heating & cooling) that are ideal for the CHP model. However, the heating and cooling needs using the CHP model result in significant excess electricity (i.e. meeting the thermal energy demands of the east campus with the CHP model generates excess electricity for the campus). Under deregulation, the excess electricity generated by the East Campus CHP plant can be bilaterally distributed via a State-established wholesale ISO-NE energy account to any other State facility as a low cost source of electric supply. The transmission and distribution component remains for the remote sites, but is reduced at the host site, or East Campus.

The diagram below shows how deregulation allows for CHP energy models to utilize excess electricity throughout the ISO-NE network. (MPS is not connected to ISO-NE but hybrid bi-lateral distribution models are available for CHP facilities in northern Maine; eventually MPS will be connected to ISO-NE if transmission upgrades are implemented as planned).

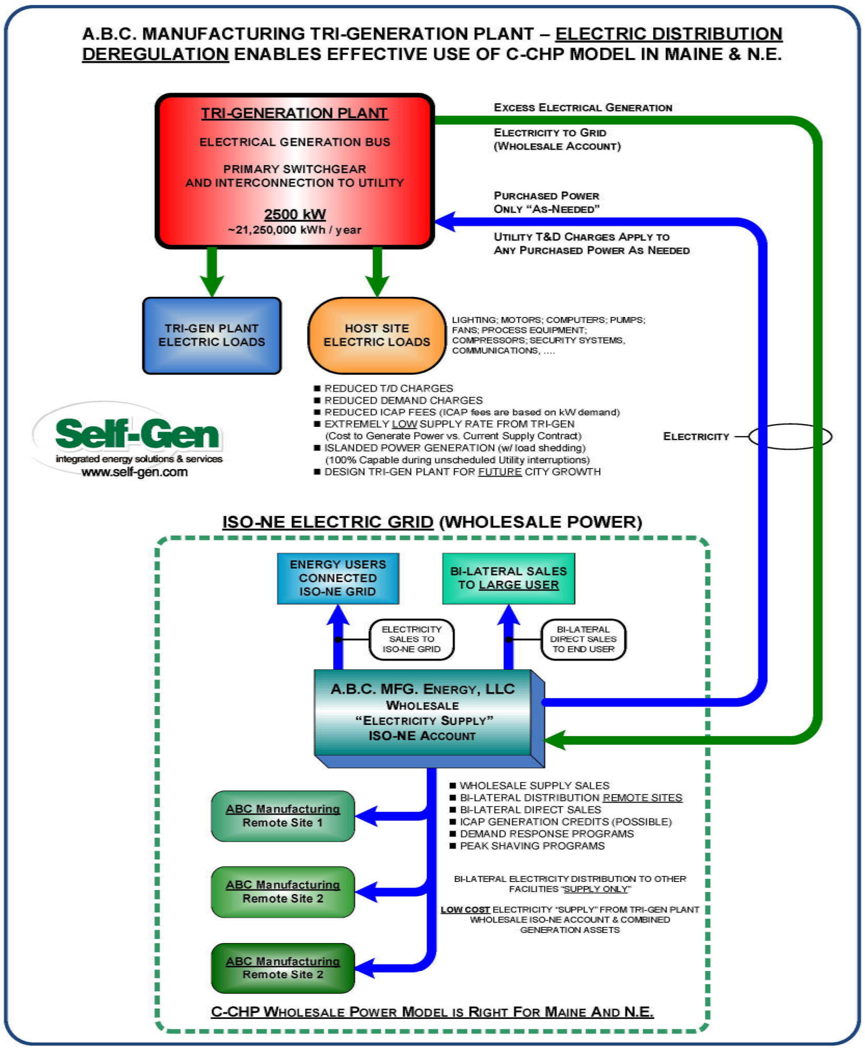


Diagram: C-CHP (Combined Cooling Heat & Power) Facility Electrical Distribution under Deregulated Structure, Source: Self-Gen, Inc

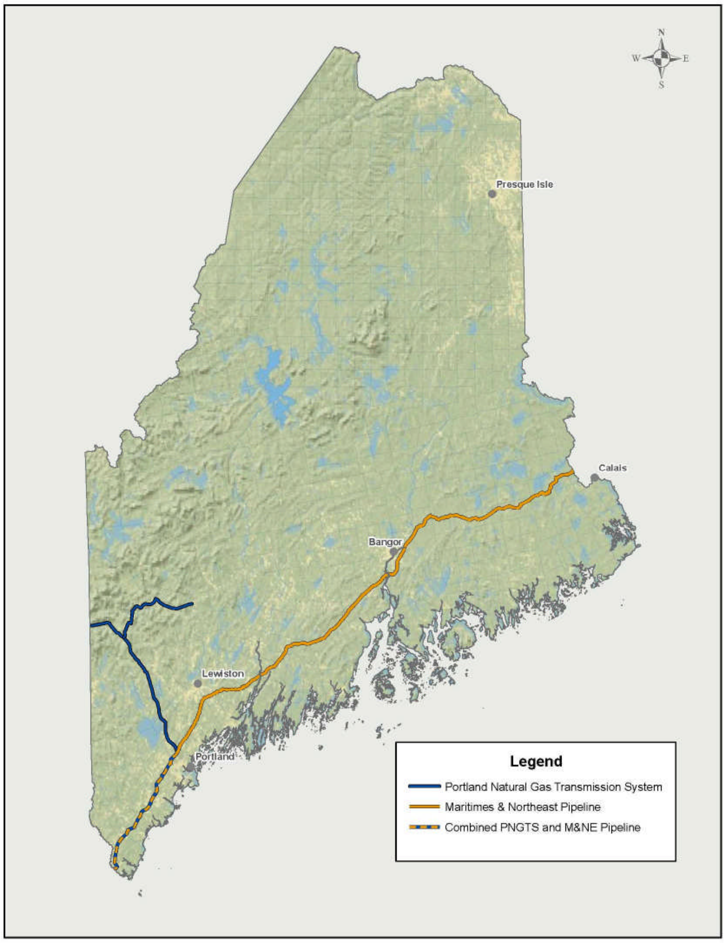
3.11 NATURAL GAS PIPELINE SUPPORT

Natural gas is a crucial element to Maine's efforts to better utilize fossil fuel usage. Natural gas CHP systems are very efficient and a clean, reliable energy source. Maine could meet or exceed its RGGI commitment by aggressively supporting and encouraging CHP applications where natural gas is currently available including at universities, hospitals, health care facilities and businesses.

Maine receives its natural gas by pipeline mostly from Canada, and ships over 50% of its natural gas to the Boston area via New Hampshire (EIA, 2010). Maine's per capita natural gas consumption is low and supply is used primarily for electricity generation. There are three natural gas transmission pipelines in Maine, the Maritimes and Northeast

Pipeline, the Portland Natural Gas Transmission System, and the Granite State Gas Transmission Co. See Figure 3-4 below.

Figure 3-4: Map of Natural Gas Transmission Pipelines



Source: Map provided by Woodard & Curran

Maine Natural Gas provides natural gas service in the towns of Windham, Gorham, Brunswick, Topsham, and Bowdoin and will bring natural gas services to Freeport in 2010. Towns currently served by Bangor Gas Company distribution system are Old Town, Orono, Veazie, Bangor, Brewer, and Bucksport (Verso Paper Mill). Unitil provides natural gas service to the following towns: Auburn, Biddeford, Cape Elizabeth, Cumberland, Eliot, Gorham, Kennebunk, Kittery, Lewiston, Lisbon, Lisbon Falls, New Gloucester, North Berwick, Old Orchard Beach, Portland, Saco, Sanford, Scarborough, South Berwick, South Portland, Wells, Westbrook and York.

The emissions reductions possible using natural gas CHP systems cannot be ignored. Natural gas is the cleanest fossil fuel and has lower emissions than oil or coal because the principle products of combustion are carbon dioxide and water vapor.

Maritimes & Northeast Pipeline President Tina Faraca explains, "The expanded Maritimes & Northeast Pipeline has created a real opportunity for more Mainers to have access to natural gas. It's the cleanest-burning conventional fuel. As we bring more supplies to the state, it will bring more opportunities for use. This project also enables the state of Maine to gain access to new suppliers and ensures reliability of our supply." The project puts Maine in a unique position, at the beginning of the United States' interstate natural gas pipeline network.(De Houx, 2010)

OEIS worked on two natural gas expansion initiatives in 2008-2009. One initiative was the "Natural Gas to Augusta" initiative. Stakeholders attended several meetings to collaborate on the concept of bringing natural gas to Augusta, specifically the State's East Campus Complex first and then the rest of Augusta. The stakeholders for this initiative were The Bureau of General Services (BGS), Togus VA Medical Center (Togus VAMC), Riverview, Maine General Hospital, Maine Natural Gas (MNG) and OEIS. Energy metrics were obtained for all the stakeholders in order to create an energy model for implementing CHP at each site. A joint letter of intent was drafted between the stakeholders and MNG in order to engage additional resources for planning. Togus VAMC was to be the first major energy host in the natural gas to Augusta initiative. Installing distribution level natural gas infrastructure to the East Campus would afford even greater expansion of natural gas infrastructure in the Augusta area. Also, it's quite possible natural gas could utilize river, rail and power rights of ways to expand natural gas beyond Augusta to Waterville and other areas.

The other natural gas initiative was the "Natural Gas to Rockland" initiative. The City of Rockland assisted in obtaining all the energy metrics for the major stakeholders in the Rockland area. Meetings were convened with MNG, FMC, city representatives, OEIS, Penn Bay Medical Center and other healthcare facilities, Warren State Prison, municipal buildings, commercial businesses, wastewater treatment plants and others.

A task force should be convened to address the barriers to expanding natural gas infrastructure in Maine since this fuel source has significant economic and environmental benefits from immediate utilization. It is expected that natural gas transmission to New England is going to grow and Maine should have a strategic plan for off-take of this critical energy source.

Natural gas, wind, solar, biomass, geothermal and other resources are all elements of Maine's quest for independence from foreign fuels. Natural gas and CHP systems are readily available for immediate use with immediate benefits. Expanding Maine's natural gas use will advance CHP development and provide an alternative fuel source for domestic heating. Natural gas continues to be a clean, efficient fuel source for Maine's CHP system. The natural gas pipeline infrastructure should be expanded and is part of the State's Comprehensive Energy Plan.

3.12 BIOMASS TO ENERGY INITIATIVES

Biomass-to-energy initiatives will become a cornerstone of Maine's economic and energy future. Fiber optimization is critical for proper utilization of this resource. "Non-competitive" biomass – biomass fiber for energy that does not come from pulp-grade or forest-products-grade feedstock, such as from tops, limbs, and slash – should be encouraged as a resource for CHP systems. Non-competitive biomass sources include residual sources like tops, limb, bark, small de-limbed trees, slash and fiber thinnings left in the wood lots. Non-competitive biomass is not considered part of the round wood feedstock being used for wood pellet production, which is often considered a competitive source with the pulp and paper industry and other forest products businesses. However, some mill residue, such as bark and sawdust, is incompatible with higher-value uses such as pulp and could provide for on-site use in CHP projects.

Small and large scale non-competitive biomass-to-energy initiatives using the Energy Eco-Park Model and point of use model are prevalent. Non-competitive biomass is also being used for creating bio-fuels and bio-chemicals prior to using pre-treated biomass residuals for biomass waste-to-energy systems. These are typically located within Energy Eco-Parks.

For example, an existing biomass stand alone power plant or one located at a mill would first pre-treat the non-competitive biomass to extract up to 20% of it's dual energy use, hemi-cellulose. After this extraction process the remaining biomass residuals are dewatered, dried and then used as normal in the existing biomass-to-energy power plant. The hemi-cellulose is then used to create a value-added revenue stream by creating bio-fuels or bio-chemicals. Maine Renewable Energy Consortium, LLC is pioneering this model in their Bio-Energy Eco-Park currently under development in South Portland industrial park (MREC, undated).

Small point-of-use biomass systems are typically used for thermal energy only like schools or CHP systems at forest products facilities, however CHP can be accomplished even with smaller biomass systems. Biomass gasification systems are typically employed for these small, medium, and large applications. Wood pellets systems are currently not used for CHP systems because the boilers utilized for commercialized pellet fuels only generate hot water or low pressure steam; higher pressure steam is required for CHP systems. There are, however, redesigned small steam engine/generators currently available for low pressure steam CHP applications.

3.13 STATE SUPPORTED BCAP MAINE FARM AGENCIES

Biomass, including wood and wood wastes, can be used efficiently in a combined heat and power system. In February 2010, the Obama Administration proposed rules to implement the Biomass Crop Assistance Program (BCAP) designed to spur the development of bio-fuel and alternative energy markets. BCAP provides financial assistance for the establishment, harvest, storage and transport of biomass feedstocks for energy production, including a variety of heat and power applications. The Maine forest product industry is positioned to benefit from the proposed rule, as sawmills and pellet manufacturers could qualify as eligible conversion facilities if they convert renewable biomass into heat or power.

3.14 CHP IN OTHER STATES

There is a wide variety in the CHP applications and in the number of CHP facilities in the nation and particularly in the Northeast States. As mentioned earlier, Maine has a total of 30 CHP facilities with a total capacity of 1,130,880 kW. The number of CHP units is considerably lower than the number of CHP units in Connecticut, Massachusetts and New York. Massachusetts has total of 124 CHP units, with a total capacity of 1,907,742 kW, and ranked second in the 2009 State Energy Efficiency Scorecard (ACEEE, Oct. 2009). Third-ranked Connecticut has 141 CHP units with a total capacity of 674,284 kW. New York has a total of 399 CHP facilities with a total capacity of 5,836,533 kW (EEA, 2009) and is ranked fifth on the State Energy Efficiency Scorecard. The subsections below represent just a sample of the programs that are in place in Massachusetts, Connecticut and New York which enable those states to increase energy efficiency through CHP.

3.14.1 Massachusetts Green Communities Program

Massachusetts is viewed as a sustainability leader because of the Green Communities program. The Green Communities Division was created in October 2008 and their goal is to help all 351 cities and towns maximize energy efficiency in public buildings, generate clean energy from renewable sources, and manage rising energy costs, which leads them toward a path of zero-net energy use (Sylvia, 2009).

To achieve these goals, the Green Communities Division is helping the cities and towns by offering the following:

- Education about the benefits of energy efficiency and renewable energy;
- Guidance and technical assistance through the energy management process;
- Facilitation of informed decisions and actions;
- Collaboration through shared best practices among cities and towns;
- Local support from regional Green Communities coordinators; and
- Opportunities to fund energy improvements.

The Green Communities program consists of four programs or services described below.

The Energy Audit Program

The EAP is designed to assess energy use by establishing benchmarks and develop individualized strategies to improve energy performance by reducing the energy demand of municipally owned buildings. This program is supported through technical assistance from the Department of Energy Resources' (DOER) Green Communities Division and the utilities/energy providers who work with communities to establish accurate benchmarks for their buildings' energy use, develop an energy strategy to improve their buildings' energy performance, and manage their energy costs (EOEEA, 2010).

Energy Management Services

Energy Management Services (EMS) is a type of performance contracting that many cities and towns choose to use to execute their energy efficiency plans. EMS contracting is a practical financing option to reduce energy costs by improving a buildings' energy and water systems with little or no up-front capital investment. This is a seamless process and the "efficiency measure are paid for by the energy and water savings guaranteed from the project by the chosen vendor" (EOEEA, 2010).

Green Communities Grant Program

The Green Communities Grant Program (GCGP) helps communities improve their overall energy efficiency. It provides up to $10 million annually to qualifying communities to fund energy efficiency initiatives, renewable energy projects and innovative projects. Communities can apply for the GCGP after they have been officially designated as a "green community" and meet firm qualification criteria. Approximately $7 million (total) is expected to be distributed in late 2010 to help Massachusetts's communities manage their energy use and costs and advance the clean energy economy (EOEEA, 2010).

MassEnergyInsight

MassEnergyInsight is a free web-based tool, provided by the Department of Energy Resources, that helps communities manage energy use and maximize energy efficiency. MassEnergyInsight compiles energy use information for municipally owned and operated buildings, streetlights, and vehicles and allows communities to execute energy management tasks (EOEEA, 2010) such as:

- Developing an energy use baseline;
- Benchmarking building performance;
- Identifying priority targets for energy efficiency investments;
- Showing the results of energy efficiency investments;
- Highlighting any irregularities in energy use;
- Developing a greenhouse gas emissions inventory;
- Generating reports for stakeholders; and
- Forecasting energy budgets.

Based on this information, it allows communities to make key energy management decisions.

3.14.2 Interconnection Standards

Massachusetts Interconnection Standards – The goal is to provide project developers with a uniform and predicable process for interconnection with the local utility. Massachusetts's interconnection standards apply to all forms of DG, including renewables, and to all customers of the state's four investor-owned utilities. The original Model Interconnection Tariff was developed by the Massachusetts DG Collaborative and adopted by the Massachusetts Department of Telecommunications and Energy (DTE) in February 2004. (The DG Collaborative – a combination of the state's utilities and DG stakeholders – was created by the DTE in October 2002 to develop interconnection standards for Massachusetts. The DG Collaborative's work encompasses all sizes of DG on both radial and secondary network systems.) The Model Interconnection Tariff includes provisions for three levels of interconnection. Simplified interconnection applies to certified, inverter-based, single-phase systems less than 10 kilowatts (kW) and certified, three-phase systems up to 25 kW in capacity. For simplified interconnection, there are no fees for the interconnection approval process and applications must be processed within 15 days. However, if the proposed interconnection is on a distribution network circuit, the utility may charge a $100 fee to review the network protector's interaction with the system. For simplified network interconnection, the aggregate generating facility capacity must be less than 1/15th of the customer's minimum load. (The issue of interconnection to network systems is particularly important in Massachusetts because network systems are commonly used in dense urban areas, such as Boston). Other interconnections can either qualify for "expedited" interconnection or will have to undergo "standard" interconnection review. Under the expedited interconnection procedures, both the time frames and fees to complete the interconnection are limited. Fees are set at $3 per kW of generator capacity, with a minimum fee of $300 and a maximum of $2,500.

3.14.3 Standby Rates

Connecticut DPUC Backup Rates – Under the capital grant program, the electric cost associated with power used when base load customer-side generation is out of service can be reduced. This is done by eliminating backup rates and demand ratchets for customers who install these projects. In addition, generation that will be interconnected to the distribution system must comply with certain standards. Further, some projects are required to participate in the ISO-NE's Demand Response Programs.

3.14.4 Grants and Rebates

NYSERDA

Eligible Technology: Combustion Turbine, Reciprocating Engine. **Eligible Fuel:** # 2 Fuel Oil, # 6 Fuel Oil, Biogas, Biomass, LFG, Natural Gas, Other, Waste Heat Recovery. **Eligible Project Size:** >0.25kW

Size of Award: Incentives are performance based and correspond to the summer-peak demand reduction (kW), energy generation (kWh), and fuel conversion efficiency achieved by the CHP system on an annual basis over a two year measurement and verification period. For the Upstate region: $0.10/kWh + $600/kW. For the Con Edison region: $0.10/kWh + $750/kW. There is a $2,000,000 incentive cap per CHP project.

The Existing Facilities Program merges the previous Enhanced Commercial/Industrial Performance Program (ECIPP) and the Peak Load Reduction Program (PLRP). There are various pre-qualified incentives under the program for energy efficiency and conservation measures. There are also performance-based incentives for combined heat and power systems. To be eligible for the performance-based CHP incentives, a CHP system must be:

- Based on a commercially available reciprocating engine or gas turbine and result in an electrical peak demand reduction during the summer capability period;
- Have a 60% annual fuel conversion efficiency based on a higher heating value (HHV) including parasitic losses;
- Use at least 75% of the generated electricity on-site; and
- Have a NOx emission rate <1.6 lbs/MWhr

There are non-performance incentive reductions under the program and a two year measurement and verification period. Incentives are paid after review and approval of the M&V data.

Multi-family buildings are ineligible for this program, as are fuel cells, micro-turbines, direct drive natural gas engines providing mechanical energy only, and CHP systems currently contracted for installation under another NYSERDA program or projects eligible to submit to the customer sited tier of the Renewable Portfolio Standard.

3.14.5 Loans

New Jersey Clean Energy Solutions Capital Investment (CESCI) Loan/Grant. Interest-free loans are available through the CESCI Loan/Grant program in amounts up to $5 million (a portion of which may be issued as a grant).

- Scoring criteria based on the project's environmental and economic development impact determines the percentage split of loan and grant awarded. The maximum grant awarded is the lesser of 80% of the amount requested or $2.5 million.
- To be eligible for the CESCI Loan/Grant, total project capital equipment costs must be at least $1 million.
    - A minimum of 50% of project costs must be covered by project sponsor(s) (includes Federal funding).
    - Aggregate state public funding cannot exceed 50% of the project cost.

- Businesses benefiting from the CESCI Loan/Grant should create or maintain jobs in New Jersey.
- The loans have a term of up to a 10-years and amortization up to 20 years based on the depreciable life of the asset financed.
- Personal guarantees are required for any person or entity with 10% or more ownership in the project, if historical Adjusted Debt Service Coverage Ratio (ADSCR) is less than 1.2:1 (based on adjusted year-end financials).
    - The EDA may consider the assignment of other public grant funding in lieu of personal guarantees, provided the other public grants are no less than 120% of the loan amount and aggregate state funding does not exceed 50% of the project cost.
- The equity requirement is 10%.

4. CASE STUDY – EASTERN MAINE MEDICAL CENTER

Eastern Maine Medical Center (EMMC) is a critical regional tertiary hospital located in Bangor, Maine, and serves as the referral hospital for the largest geographical area of any hospital in the Northeast. Prior to 2006, the existing utilities and infrastructure at the hospital consisted of the following:

- Duel fuel high pressure steam boiler plant and distribution system;
- 2,300 ton electric chilled water plant;
- Two 12.4 kilovolt feeders on overhead poles from Bangor Hydro Electric Company with primary switchgear and site distribution; and
- Two 1,500 kilowatt diesel emergency generator sets and one 500 kilowatt set.

Between 1995 and 1997, EMMC began looking into turbine technology for its Bangor campus for the following reasons (EMMC, 2010; Mylen, 2009):

- The medical center never closes, and must remain operational at all times.
- The severe and ever-changing weather that affects central, eastern, and northern Maine is known to cause extended electrical outages and EMMC must deliver healthcare no matter what the weather conditions are. Having dual fuel capability (natural gas or oil) would greatly improve EMMC's ability to operate under any circumstances.
- High utility rates, high process thermal load, and a 12-month thermal requirement for heating or cooling.
- To reduce emissions of NOx, CO, SO2, VOCs, particulate matter, and other greenhouse gases.
- EMMC is an economic driver in the region and is mandated by the State of Maine to find ways to provide affordable and efficient healthcare for all of the people of central, eastern, and northern Maine. The CHP project would trim energy costs at the medical center by approximately $1,000,000 per year.

In 1998 an ice storm had a catastrophic effect on EMMC and the surrounding area, resulting in the loss of dependable power for more than 16 hours and reinforcing the fact that hospitals need secure electrical power. Much of the utility infrastructure was damaged, causing many homes and businesses to be without power for time periods that ranged from several days to six weeks.

In the spring/summer of 2003, EMMC assembled a team to assist with the procurement, design, construction, and information distribution for the CHP project. Team members included EMMC, Cianbro Construction Corporation, Vanderweil Engineers, Solar Turbines, Inc., and the International District Energy Association.

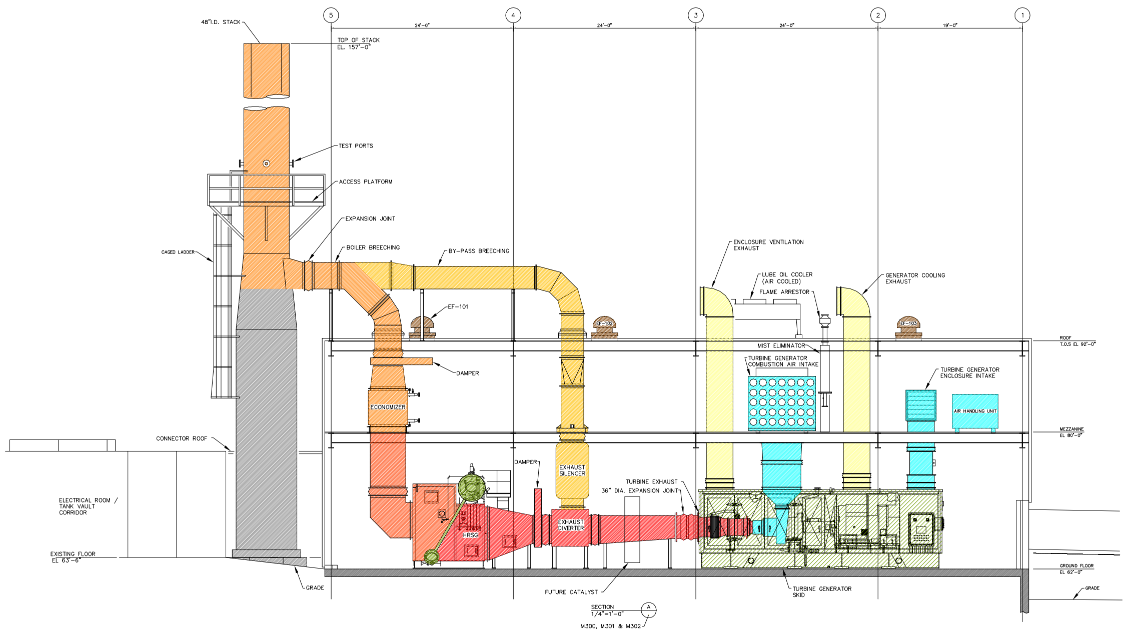
In the fall of 2003, after three years of working with Vanderweil Engineers to determine the feasibility of using turbine technology, EMMC applied for the DOE's Distributed Energy System Application grant to help finance the turbine project. In May 2004, EMMC was awarded a $3 million dollar DOE grant (administrated by Oak Ridge National Lab) to build and operate a CHP Plant. The balance would be internally financed by EMMC. On February 4, 2005, EMMC was awarded a Certificate of Need (CON) by the State of Maine to start construction of the CHP Plant, and construction of the Plant commenced in July 2005. The CHP Plant at EMMC was fully tested and online on October 16, 2006.

Figure 4-1 shows the CHP System, which consists of the following elements:

- Solar Centaur 50, 4.6 megawatts @ ISO with un-fired Heat Recovery Steam Generator (HRSG) generating 25,000 pounds per hour flow (PPH) of steam; and
- New 500 ton steam absorption chiller and ancillaries.

EMMC will stay connected to the Bangor Hydro Grid and still imports approximately 20% of its electricity from the grid on an annual basis. The generator connected to the turbine is 4.6 megawatts, which is equal to supplying electricity to 46,000 one-hundred watt bulbs or approximately 400 average size homes. The heat output of the HRSG (boiler) is equivalent to heating approximately 300 homes. In addition, during the summer months, surplus steam from the plant can be used to help cool the hospital through the 500 ton steam absorption chiller and two new cooling towers. This output is equivalent to helping cool approximately 500 homes on a hot day.

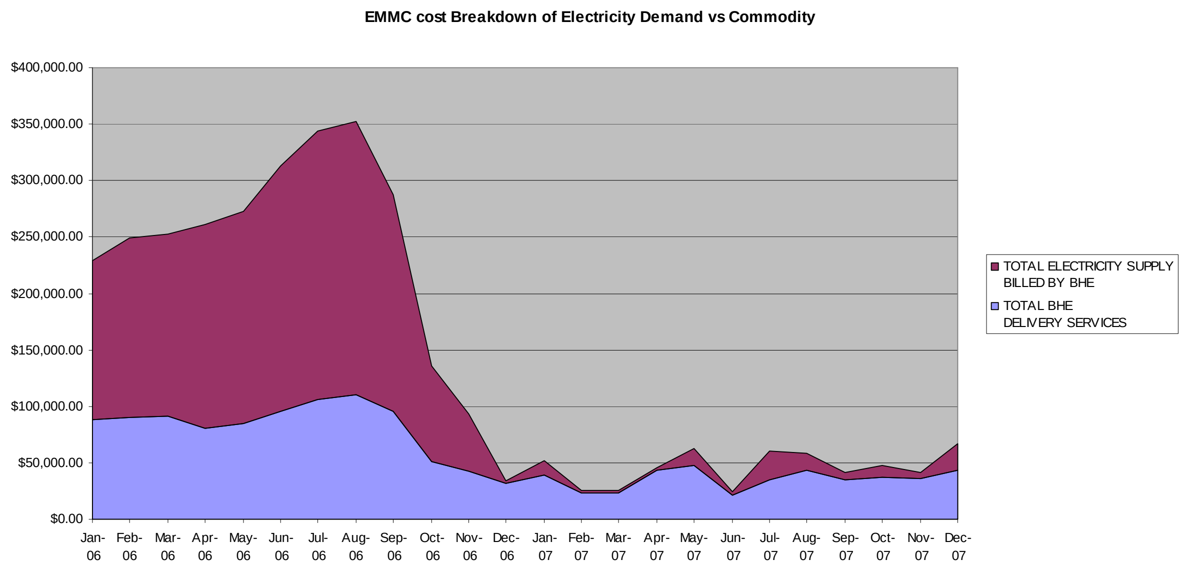
Figure 4-1: CHP System



Source: Mylen, 2009

The cost of the project was approximately $8.2 million and EMMC's cost was approximately $5.2 million. The expected energy savings are at least $1 million per year, yielding complete payback in less than 5 years. Additional benefits include reduced emissions, increased thermal and heating capacity, and emergency backup power. Figure 4-2 shows the cost breakdown of electrical demand versus commodity from January 2006 to December 2007.

Figure 4-2: EMMC Cost Breakdown



Source: Mylen, 2009

As stated above, the CHP Plant at EMMC was fully tested and online on October 16, 2006. The cost savings have been greater than expected and the system has already paid for itself in approximately three years.

5. IDENTIFYING BARRIERS

5.1 INTERCONNECTIONS (TECHNICAL & ECONOMIC)

Interconnection standards are the rules that establish uniform processes and technical requirements for utilities when DG systems of a particular type and size are connected to the grid. In general, interconnection standards consist of two components: technical requirements and an application process. Technical issues relate to the size and type of the generator and its connection and operation procedures that may affect grid stability and worker and public safety. Standards also make the application process as simple as possible, especially for small-scale DG developers who are more likely to be deterred by a strenuous application process because of their relatively small generating capacities.

Without uniform interconnection standards, consumers may find it time consuming and costly to install DG systems. Statewide interconnection standards provide clear and reasonable rules for connecting DG systems to the electric grid. Complexity, length of time to completion, and costly processes may act as reasons for the abandonment of efforts in installing DG systems.

As of February 2008, 31 states had adopted standard interconnection rules for DG. These include: Arkansas, Arizona, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Indiana, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Mexico, New Jersey, Nevada, New York, North Carolina, Ohio, Oregon, Pennsylvania, South Carolina, Texas, Utah, Vermont, Washington, Wisconsin and Wyoming. Additionally, eleven other states are developing standards (*i.e.,* Alaska, District of Columbia, Idaho, Illinois, Iowa, Kansas, Kentucky, Maryland, South Dakota, Tennessee and West Virginia). Of the states that have adopted statewide interconnection standards, a range of technologies, including CHP systems, have been covered within the scope of the standard. According to a US EPA assessment, fifteen states (California, Connecticut, Delaware, Indiana, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Nevada, Ohio, Oregon, Pennsylvania, Vermont and Washington) have standards that are considered "DG-friendly."

After restructuring, Maine did not adopt statewide uniform interconnection standards. Instead, each utility used different procedures and each had its own requirements for the interconnection of small generators to their distribution systems. However, in 2003 the MPUC stated that it was "…not aware of any unwarranted barriers deriving from the interconnection procedures and the Federal Energy Regulatory Commission (FERC) [was] in the process of addressing the matter." Since 2003, FERC and other organizations have created a number of model interconnection standards that states may use for statewide needs. The three major uniform rules are FERC's Small Generator Interconnection Procedure (SGIP), Interstate Renewable Energy Council's (IREC) model standards, and Mid-Atlantic Demand Resources Institute's (MADRI) model standards.

FERC's SGIP has been the most widely used. The IREC model is based on the FERC model, but a few changes were made to improve timeframes and to lower remaining barriers to small generation. MADRI is less utilized by other states. It was originally developed for the Mid-Atlantic States and has at least informed Pennsylvania's small generator interconnection process, but few others.

During the 2008 session, the Maine State Legislature enacted "Resolve, To Encourage Renewable Energy and Energy Conservation in Maine." Section 2 of the Resolve directed the MPUC to conduct a review of the advisability of statewide interconnection standards for small renewable generation facilities. The MPUC concluded in its Draft Report that statewide interconnection procedures for Maine's utilities should be imposed. In particular, the MPUC concluded that "Standardized rules [would] increase the efficiency of the interconnection process, encourage the increased use of renewable energy and energy conservation, and may foster an easier business environment for the companies that sell and install small generation systems."

On January 4, 2010, the MPUC issued an order in docket No. 2009.219 adopting statewide interconnection procedures which apply to all technologies, regardless of system size. The following points are included in these interconnection procedures (IREC, 2010):

- All state-jurisdictional interconnections are applicable, regardless of size of the generator.
- Four Interconnection levels of review (including a non-export level).
- Spot and area network interconnection provisions are the same as those found in IREC's model procedures.
- Disconnect switch is prohibited for small inverter-based systems.
- Application fees are $50 for level 1; $50 + $1/kW for other levels.
- Engineering fees: fixed at $100/hour.
- Insurance provisions adopted levels from IREC's 2009 model.
- Timelines were similar to IREC's model.
- The dispute resolution adopts a flexible approach that allows MPUC to tailor to the circumstances, including use of informal methods such as teleconferences.

5.2 UTILITY ISSUES ON SAFETY AND COST SHIFTING

During the task force meetings, the largest barriers raised by the T&D utilities were 1) safety of the CHP interconnections and 2) cost shifting to rate payers for lost revenues.

Interconnection safety should not be taken lightly, but it should be noted that the technical component of interconnections follows very clear national guidelines for power generation, protection (safety), relaying, metering and controls. T&D utilities are upgrading or replacing their own protection and automation systems with new multifunctional protection relaying and metering. Maine has adopted statewide interconnection standards that address safety as a barrier.

During the CHP stakeholder meetings, "cost shifting" to the rate payers was one of the largest concerns of electric T&D utilities in the advancement toward CHP models in Maine. T&D utility rates in the state of Maine, as well as most other electric deregulated jurisdictions, are based upon the cost of serving customers, as well as the allowed regulated rate of return on the rate base. The cost of service and allowed rate of return components make up a utility's revenue requirement. A T&D utility's revenue requirement and rates are generally set through MPUC and FERC rate cases whereby rates or alternative rate plans establish rates for a predetermined period of time. There is no electric rate that a regulated utility charges that isn't explicitly approved through a regulatory process that, in many cases, has various interested stakeholders engaged throughout the process.

When rates are set and designed, these utility rates reflect the average cost to serve various classes of customers and this average cost may be higher or lower than the marginal cost to serve any one specific customer. Since an electric utility has an obligation to serve all its customers, which ultimately implies that it has the obligation to build the infrastructure to serve these customers at any peak or off-peak demand time period, the excess costs associated with some customers are spread across all customers and borne by all ratepayers.

When an existing electricity customer converts to CHP technology, their electricity consumption (kWh) drops, but is not totally eliminated. CHP customers generally remain connected to the electric system and take service when the CHP generator is out of service. Consequently, the revenue that a CHP customer contributes through minimal consumption may not be sufficient to cover the cost of service associated with that customer; therefore, the cost to serve the CHP customer may ultimately be shifted to other customers.

In an effort to reduce or eliminate "cost shifting" to other customers, some utilities, such as Bangor Hydro Electric Company, have sought to institute an approved tariff that accounts for the cost to provide standby electric service. Some feel that standby rates approved by a regulatory body generally represent an example of compromise between the CHP customer, other ratepayers, and the utility.

Some proponents of CHP consider standby rates to be excessive considering the limited use of the electrical system; however, others say that the cost to build and maintain the system is the same whether it is used by the customer 365 days a year or only 1 day a year. These stakeholders state that the CHP customer has lower energy (kWh) consumption, yet the utility must provide the infrastructure needed to serve the maximum demands (kW) of the customer. Generally speaking, CHP customers have high demands requiring a robust electrical system to serve them when their generator is out of service.

Electric utilities are allowed to recover their costs to serve their customers through rates by charging customers based on their energy consumption or demand levels. Some argue that standby rates attempt to balance the interests of the CHP customers, the ratepayer and the utility through the application of below average delivery rates and characteristics of service that lessen the ratepayer impact of normal cost recovery. The appropriate approach will require leadership to create a straight-forward policy that addresses this issue for the best interest of Maine. Perhaps there will be a hybrid model that solves this issue.

5.3 LIMITED FUEL SOURCE INFRASTRUCTURE

Natural gas is an ideal fuel source for small and medium sized CHP systems. Maine should maximize the advancement of the CHP energy model throughout existing natural gas infrastructure locations. A strong natural gas expansion initiative would create and retain Maine jobs as well as help realize our Regional Greenhouse Gas Initiative (RGGI) goals. There is currently an effort underway for the installation of liquefied natural gas (LNG) stations strategically located along major transmission pipelines. LNG would also help advance the CHP model where biomass-fueled systems may not be economically or technically feasible.

Biomass resources are also excellent fuel sources for CHP systems and extensive evaluation of Maine's biomass or wood fiber feedstock availability is ongoing. The cost for this feedstock can be impacted by various factors, including competitive use demands from forest products, pulp & paper and wood pellet industries. Further discussion is needed as to whether biomass CHP plants should be defined as non-competitive by specifying that their supplier provide feedstock fiber only from tops, limbs and small de-limbed trees, and other sources and not from pulp grade sources.

Bio-gas can be produced from many sources including capped landfills, anaerobic digesters and renewable fuel conversion processes. Landfill gas is already being used in Maine at the Hampton landfill and other smaller landfills and is being proposed for the West Old Town Landfill. An opportunity exists for the Energy Eco-Park Model to be employed at the Old Town landfill by constructing a bio-gas tri-generation plant as an energy hub for the Eco-Park. The Energy Eco-Park tri-generation plant would be designed to supply electricity and steam for heating and cooling for park tenants (new businesses) as well abutting neighbors, including the University of Maine in Orono and the Old

Town Fuel and Fiber Mill. This model would help businesses and the University control energy costs as well as create economic development opportunities by enticing new businesses into the Park with low-cost renewable energy guarantees.

Anaerobic digesters create bio-gas by digesting organic matter including agricultural animal waste, agricultural plant waste and energy crops. In this model, the bio-gas created is used in a reciprocating engine/generator as a fuel source or in traditional combustion boilers. The fuel can be used for CHP Model 1, 1A, or 2.

Bio-fuel is a large area for CHP fuel development or fuel optimization. For biomass-sourced CHP applications, the developer may want to consider the pre-treatment of the biomass prior to being utilized in the CHP plant in order to extract value-added energy content. In this model, the biomass is pre-treated and hemi-cellulose is extracted for use in creating bio-butanol (transportation fuel) or bio-chemicals. The remaining pre-treated biomass is then used in the CHP facility. In any case, all developers should be encouraged to explore and evaluate emerging technologies that may enhance their project's value.

Bio-oil is another fuel that is being created from non-competitive biomass to create a cellulose-based replacement for #2 fuel oil and # 6 fuel oil. In the CHP model for producing bio-oil, the refinery is co-located at a forest products facility that requires electrical and thermal energy. Some of the bio-oil produced is then used in a combustion-turbine-generator with heat recovery boiler to create electricity and steam for the host. The remaining bio-oil is sold to the market.

On this topic, we suggest further review of the "Liquid Biofuels Policy for Maine" report submitted by OEIS to the legislature in February of 2008.

5.4 LACK OF PRE-ENGINEERING PROJECT DEVELOPMENT FUNDING

For over a decade, one of the largest barriers to the advancement of the CHP energy model has been funding for pre-development and development. Even large Fortune 100/500 companies do not have the budgets to fund the feasibility studies that help build the business case for advanced projects. In most cases where a feasibility study is completed, the comprehensive pre-engineering funding is almost non-existent. Pre-engineering is the process by which a fiscal grade project scope and budget are created to within +/- 10%. Once this level of engineering has been completed, then traditional and non-traditional funding can be secured for project implementation.

One of the biggest barriers for launching CHP projects in Maine has been lack of funding for feasibility studies and comprehensive pre-engineering.

6. INCENTIVES AND FUNDING PROGRAMS

6.0 TYPES OF INCENTIVES

The incentive and funding program descriptions in Section 6 are primarily drawn from US EPA's CHP Partnership Program. For the most current incentives see the CHP Partnership webpage: http://www.epa.gov/chp/index.html.

For CHP systems, a number of Federal incentives and funding programs are available. Types of incentives include tax credits, rebates, grants and loans. Some of these incentives expire by the end of 2010 while others terminate much later. Many of the incentives were created or are supported by the adoption of recent Acts, such as the Energy Independence and Security Act of 2007 (EISA) and the Energy Policy Act of 2005 (EPACT). The Internal Revenue Service, Department of Energy and the Department of Agriculture all administer funds for various types of programs. For a more detailed description of individual grants and incentives offered for CHP systems, please refer to Appendix F.

CHP incentive and funding opportunities are offered by various government entities throughout the country, many at the state and federal level. These opportunities take a variety of forms, including:

- Financial incentives, such as grants, tax credits, low-interest loans, favorable partial load rates (e.g., standby rates), and tradable allowances.
- CHP or biomass project development can be expedited with regulatory treatment, such as standard interconnection requirements, net metering, and output-based regulations that remove unintended barriers.

6.1 FEDERAL INCENTIVES FOR DEVELOPING COMBINED HEAT AND POWER PROJECTS

In 2008 and early 2009, two key federal bills were passed that include provisions that support CHP:

- The Energy Improvement and Extension Act of 2008 (EIEA) passed by Congress on October 3, 2008, significantly expanded federal energy tax incentives and introduced the CHP investment tax credit.
- The American Recovery and Reinvestment Act of 2009 (ARRA), passed in February 2009, expands and revises tax incentives for CHP and provides funding opportunities for CHP and waste energy recovery.

Note that many of the programs authorized in EIEA or ARRA are still under development.

6.2 TAX PROVISIONS

6.2.1 CHP Investment Tax Credit (ITC)

EIEA created a 10% investment tax credit (ITC) for the costs of the first 15 MW of CHP property. To qualify for the tax credit, the CHP system must:

- Produce at least 20% of its useful energy as electricity and 20% as thermal energy;
- Be smaller than 50 MW;
- Be constructed by the taxpayer or have the original use of the equipment begin with the taxpayer;
- Be placed in service after October 3, 2008 and before January 1, 2017; and

- Be 60% efficient on a lower heating value basis.

The 60% efficiency requirement does not apply to CHP systems that use biomass for at least 90% of the system's energy source. The ITC may be used to offset the alternative minimum tax and the CHP system must be operational in the year in which the credit is first taken.

ARRA allows taxpayers eligible for the CHP ITC to receive a grant from the U.S. Department of the Treasury instead of taking the ITC for new installations. For eligible CHP projects, Treasury will make payments to qualified applicants in an amount equal to 10% of the system cost. The Treasury Department is now accepting applications for the grant program. For more information including the guidance document (PDF), terms and conditions (PDF), and a sample application (PDF), please visit the U.S. Department of Treasury's Web site. To apply for a grant in lieu of the tax credit, please visit the application web site.

The CHP ITC is claimed through IRS Form 3468, available on the IRS's Web site. Facility owners who claim the ITC can not claim the production tax credit (PTC).

6.2.2 Investment Tax Credits for Micro-Turbines and Fuel Cells

The EIEA extended the ITC to micro-turbines and fuel cells. For micro-turbines, the credit is equal to 10% of expenditures, with no maximum limit stated (explicitly), but it is capped at $200 per kW of capacity. Eligible property includes micro-turbines up to two MW that have an electricity-only generation efficiency of 26% or higher.

For fuel cells, the credit is equal to 30% of expenditures, with no maximum credit. However, the credit for fuel cells is capped at $1,500 per 0.5 kW of capacity. Eligible property includes fuel cells with a minimum capacity of 0.5 kW that have an electricity-only generation efficiency of 30% or higher. (The credit for property placed in service before October 4, 2008, is capped at $500 per 0.5 kW.)

The ITC for both micro-turbines and fuel cells is available for eligible systems placed in service on or before December 31, 2016. As with the CHP ITC, facility owners can choose to receive a one-time grant equal to 30% of the construction and installation costs for the facility, as long as the facility is depreciable or amortizable. To be eligible, the facility must be placed in service in 2009 or 2010, or construction must begin in either of those years and be completed prior to the end of 2013. For more information including the guidance document, terms and conditions and a sample application, please visit the U.S. Department of Treasury's Web site. To apply for a grant in lieu of the tax credit, please visit the application web site.

The ITC for micro-turbines and fuel cells is claimed through IRS Form 3468, available on the IRS's Web site. Facility owners who claim the ITC can not claim the production tax credit (PTC).

6.2.3 Renewable Electricity Production Tax Credit

The EIEA extended the PTC for biomass, geothermal, hydropower, landfill gas, waste-to-energy, and marine facilities and other forms of renewable energy through 2010, and the ARRA further extended the tax credit through 2013. The renewable electricity PTC is a per kWh federal tax credit included under Section 45 of the U.S. tax code for electricity generated by qualified energy resources. The PTC provides a corporate tax credit of 1.0 cents/kWh for landfill gas, open-loop biomass, municipal solid waste resources, qualified hydropower, and marine and hydrokinetic (150 kW or larger). Electricity from wind, closed-loop biomass, and geothermal resources receive 2.1 cents/kWh. Projects that receive other government grants or subsidies receive a discounted tax credit.

The ARRA allows taxpayers eligible for the federal PTC to take the federal business energy investment tax credit (ITC) or to receive a grant from the U.S. Treasury Department instead of taking the PTC for new installations. The Treasury Department issued Notice 2009-52 in June 2009, giving limited guidance on how to take the federal business energy investment tax credit instead of the federal renewable electricity production tax credit. The Treasury Department is now accepting applications for the grant program. For more information including the guidance document, terms and conditions and a sample application, please visit the U.S. Department of Treasury's Web site.

The Renewable Energy PTC is claimed through IRS Form 8835 and IRS Form 3800.

6.2.4 Bonus Depreciation

Under the federal Modified Accelerated Cost-Recovery System (MACRS), businesses may recover investments in certain property through depreciation deductions. The MACRS establishes a set of class lives for various types of property, ranging from three to 50 years, over which the property may be depreciated. The ARRA extended the five-year bonus depreciation schedule through 2010 and includes CHP, thereby allowing 50% of the depreciation value to be taken in the first year and the remainder over the following four years.

To qualify for bonus depreciation, a project must satisfy these criteria:

- The property must have a recovery period of 20 years or less under normal federal tax depreciation rules;
- The original use of the property must commence with the taxpayer claiming the deduction;
- The property generally must have been acquired during 2009 or 2010; and
- The property must have been placed in service during 2009 or 2010.

The bonus depreciation rules do not override the depreciation limit applicable to projects qualifying for the federal business energy tax credit. Before calculating depreciation for such a project, including any bonus depreciation, the adjusted basis of the project must be reduced by one-half of the amount of the energy credit for which the project qualifies.

For more information on the federal MACRS, see IRS Publication 946, IRS Form 4562: Depreciation and Amortization, and Instructions for Form 4562.

6.2.5 Advanced Energy Manufacturing Tax Credit

ARRA established the advanced energy manufacturing tax credit to encourage the development of a U.S.-based renewable energy manufacturing sector. ARRA authorizes the Department of the Treasury to issue $2.3 billion of credits under the program. In any taxable year, the investment tax credit is equal to 30% of the qualified investment required for an advanced energy project that establishes, re-equips, or expands a manufacturing facility that produces any of the following:

- Equipment and/or technologies used to produce energy from solar, wind, geothermal, or other renewable resources;
- Fuel cells, micro-turbines, or energy-storage systems for use with electric or hybrid-electric motor vehicles;
- Equipment used to refine or blend renewable fuels; or

- Equipment and/or technologies to produce energy-conservation technologies (including energy-conserving lighting technologies and smart grid technologies).

Qualified investments generally include personal tangible property that is depreciable and required for the production process. Other tangible property may be considered a qualified investment only if it is an essential part of the facility, excluding buildings and structural components.

To be eligible for the tax credit, a project must be certified by the Department of the Treasury. In determining which projects to certify, ARRA directs the Department of the Treasury to consider those projects that most likely will:

- Be commercially viable;
- Provide the greatest domestic job creation;
- Provide the greatest net reduction of air pollution and/or greenhouse gases;
- Have the greatest potential for technological innovation and commercial deployment;
- Have the lowest levelized cost of generated (or stored) energy or the lowest levelized cost of reduction in energy consumption or greenhouse gas emissions; and
- Have the shortest project time from certification to completion.

After certification is granted, the taxpayer has up to one year to provide additional evidence that the requirements of the certification have been met and three years to put the project in service.

On August 13, 2009, the Department of the Treasury announced the availability of funds under the program and preliminary applications were due to DOE September 16, 2009, followed by final applications being due to DOE and IRS on October 16, 2009. By January 15, 2010, the IRS certified or rejected applications, and notified the certified projects with the approved amount of their tax credit. Awardees received acceptance agreements from the IRS by April 16, 2010. Credits will be allocated until the program funding is exhausted. Subsequent allocation periods will depend on remaining funds.

6.2.6 Clean Renewable Energy Bonds

The 2005 Energy Policy Act created Clean Renewable Energy Bonds (CREBs) within Section 54 of the U.S. tax code. Unlike traditional bonds that pay interest, tax credit bonds pay the bondholders by providing a credit against their federal income tax. In effect, CREBs provide interest-free financing for clean energy projects.

In 2008, EIEA provided authority for the issuance of an additional $800 million in "new" CREBs, and in 2009, ARRA allocated an additional $1.6 billion for CREBs. The 2008 legislation also extended the deadline by which bonds must be issued for previous allocations to December 31, 2009.

The types of projects for which bonds can be issued include renewable energy projects utilizing landfill gas, wind, biomass, geothermal, solar, municipal solid waste, small hydroelectric, marine, and hydrokinetic. The IRS has determined that facilities "functionally related and subordinate" to the generation facility itself are also eligible for CREB financing. Examples of these auxiliary components include transmission lines and interconnection upgrades.

The EIEA directs the IRS to allocate the bonding authority equally among electric cooperatives, government entities, and public power producers. Other changes for "new" CREBs are as follows:

- The federal tax credit is reduced to 70% of the interest payment;
- The bond holder can transfer the tax credit to another party;
- Taxpayers can carry forward unused credits into future years; and
- Bond proceeds must be used within three years or a request for an extension must be made.

6.2.7 Qualified Energy Conservation Bonds

The EIEA created a new funding mechanism called Qualified Energy Conservation Bonds (QECBs), similar to the CREB model in which a bondholder receives tax credits in lieu of interest. The act authorizes state, local, and tribal governments to issue energy conservation bonds to finance qualified projects. The 2008 legislation allows the IRS to distribute up to $800 million in bond authorizations. In 2009, ARRA provided an additional $2.4 billion in bonding authority. The bond proceeds can be used to finance capital expenditures that achieve one of the following goals:

- Reduction of energy consumption by at least 20%;
- Implementation of a green community program; or
- Electricity generation from renewable resources in rural areas.

An IRS notice contains more details about the bond program, including an outline for the bond cap for each state. The IRS is expected to issue further guidance on how the program will work soon.

6.3 GRANTS/PRODUCTION INCENTIVES

6.3.1 Deployment of CHP Systems, District Energy Systems, Waste Energy Recovery Systems, and Efficient Industrial Equipment

On June 1, 2009 the DOE announced plans to provide $156 million from ARRA to support projects that deploy efficient technologies in the following four areas of interest:

- CHP;
- District energy systems;
- Industrial waste energy recovery; and
- Efficient industrial equipment.

Applications were due by July 15, 2009.

On November 3, 2009, the DOE announced its award of more than $155 million to 41 industrial energy efficiency projects across the country. The nine largest projects, totaling $150 million and leveraged with $634 million in private industry support, will promote the use of CHP, district energy systems, waste energy recovery systems, and energy efficiency initiatives at hospitals, utilities, and industrial sites.

A full list of recipients is available on the DOE's Industrial Technology Program Web site.

6.3.2 Combined Heat and Power Systems Technology Development Demonstration

The Combined Heat and Power Systems Technology Development Demonstration aims to accelerate the development and deployment of CHP technologies and systems to work towards a goal of increasing U.S. electricity generation capacity from CHP. Applications for CHP technology development and demonstration will be considered for three areas of interest. The areas of interest are based on the output range of the CHP system and are as follows:

- Large CHP systems (greater than or equal to 20 MW);
- Medium CHP systems (greater than or equal to 1 MW to less than 20 MW); and
- Small CHP systems (greater than or equal to 5 kW to less than 1 MW).

All three areas sought applicants that can perform research, development, and demonstration of technologies that increase the efficiency and reduce the cost of CHP systems. Applications were due by August 4, 2009.

The large CHP systems have an estimated total budget of $30 million – $15 million from the DOE. The medium systems have an estimated budget of $30 million – $15 million from the DOE. Small CHP systems have an estimated budget of $20 million – $10 from the DOE.

Funded demonstration projects are aimed at accelerating the project development process through collaborative partnerships with key industry partners. Key technologies are those capable of sizable energy savings and corresponding greenhouse gas emissions reductions while providing a least cost approach to compliance with relevant emissions regulations. All technologies have a defined pathway to commercialization.

6.3.3 Waste Energy Recovery Registry and Grant Program

Title IV of the Energy Independence and Security Act of 2007 contains extensive new provisions designed to save energy in buildings and industries. Subtitle D of the Act focuses on industrial energy efficiency and contains new provisions designed to improve energy efficiency by promoting CHP, waste energy recovery, and district energy systems. EPA is required under EIEA Subtitle D, Part E to establish a recoverable waste energy inventory program.

Subject to appropriations, the EIEA also directs the DOE to develop a waste energy recovery incentive grant program to provide incentive grants to:

- Owners and operators of projects that successfully produce electricity or incremental useful thermal energy from waste energy recovery;
- Utilities purchasing or distributing the electricity; and
- States that have achieved 80% or more of recoverable waste heat recovery opportunities.

US EPA's obligation under EISA is to develop an ongoing survey of major domestic industrial and large commercial sources, as well as the sites at which the sources are located, and to conduct a review of each source for the quantity and quality of potential waste energy produced. This survey is a necessary first step to gather the data needed to establish the Registry of Recoverable Waste Energy Sources (Registry). The purposes of the survey and Registry are to:

- Provide a list of the economically feasible existing waste energy recovery opportunities in the US, based on a survey of major industrial and large commercial sources.

- Provide state and national totals of the existing waste energy recovery opportunities, as well as the potential criteria pollutant and greenhouse gas emissions reductions that could be achieved with the capture and use of the waste energy recovery opportunities listed in the Registry.
- Serve as the basis for potential waste energy recovery projects to qualify for financial and regulatory incentives as described in Energy Policy and Conservation Act (EPCA) Sections 373 "Waste Energy Recovery Incentive Grant Program" and 374 "Additional Incentives for Recovery, Use, and Prevention of Industrial Waste Energy," as added by EISA.

On July 16, 2009, the US EPA Administrator signed a draft rule which proposes to establish the criteria for including sources or sites in the Registry, as required by EISA. The draft rule also proposes the survey processes by which US EPA will collect data and populate the Registry. The proposed rule would apply to major industrial and large commercial sources as defined by US EPA in the rulemaking. The proposed rule would not require the installation of new monitoring equipment, rather it would require only that sources above certain threshold levels that wish to be included in the Registry enter specific already-monitored data points into the survey. The survey is a software tool that will calculate the quantity and quality of potentially recoverable waste energy.

The proposed rule and relevant background information can be accessed on the Waste Energy Recovery Registry Web site. Public comments were accepted through September 21, 2009. For general questions about the proposed rule, contact Katrina Pielli.

6.3.4 EPA Clean Water and Drinking Water State Revolving Funds

ARRA provides funding for states to finance high-priority infrastructure projects needed to ensure clean water and safe drinking water. It provided $4 billion for the Clean Water State Revolving Fund (CWSRF) program, in place since 1987, including funds for Water Quality Management Planning Grants. ARRA also provided $2 billion for the Drinking Water State Revolving Fund (DWSRF) program, in place since 1997. States must provide at least 20% of their grants for green projects, including green infrastructure, energy or water efficiency, and environmentally innovative activities. CHP projects at wastewater treatment facilities qualify for grants under the 20% set-aside.

The CWSRF program is available to fund a wide variety of water quality projects, including all types of nonpoint source, watershed protection or restoration, and estuary management projects, as well as more traditional municipal wastewater treatment projects. Through the CWSRF program, each state and Puerto Rico maintain revolving loan funds to provide independent and permanent sources of low-cost financing for a wide range of water quality infrastructure projects. Funds to establish or capitalize the CWSRF programs are provided through federal government grants and state matching funds (equal to 20% of federal government grants).

The DWSRF program provides public water systems with affordable financing for infrastructure improvements which enable them to comply with national primary drinking water standards and protect public health. States use federal capitalization grant money awarded to them under this program to set up an infrastructure funding account from which assistance is made available to public water systems. Loans made under the program can have interest rates between 0% and market rate and repayment terms of up to 20 years. Loan repayments to the state provide a continuing source of infrastructure financing.

More information and program guidance, including grant allocations to each of the states is available through the Clean Water and Drinking Water State Revolving Funds Web site.

6.3.5 Renewable Energy Production Incentive

The Renewable Energy Production Incentive (REPI) Program was created by the Energy Policy Act of 1992 and reauthorized by the Energy Policy Act of 2005 to extend through 2026. REPI provides financial incentives for renewable energy electricity produced and sold by qualified renewable energy generation facilities, which include not-for-profit electrical cooperatives, public utilities, state governments, U.S. territories, the District of Columbia, and Indian tribal governments. The facilities are eligible for annual incentive payments of approximately 2 cents/kWh for:

- Landfill Gas
- Solar
- Wind
- Geothermal
- Biomass
- Livestock Methane
- Ocean
- Fuel cells using hydrogen derived from eligible biomass facilities

To be eligible, qualified renewable energy facilities must be operational before October 1, 2016. Funding is subject to annual appropriation, and the program has historically been under-funded. During years in which there is a funding shortfall, legislation requires DOE to allocate 60% of REPI funds to solar, wind, ocean, geothermal, or closed-loop biomass technologies and the remainder to landfill gas, livestock methane, and open-loop biomass projects. If funds are not sufficient to make full payments to all qualifying facilities, payments are made to those facilities on a pro rata basis.

To assist DOE in its budget planning, DOE requests that the owner or operator of a qualified renewable energy facility provide notification at least six months in advance of electricity generation. To receive payment, qualified facility owners and operators submit information, such as monthly electricity generation, to DOE during the first quarter (i.e., October 1 through December 31) of the next fiscal year.

More information and details about the application procedures are provided on the REPI Web site and in the Partnership's funding database.

6.3.6 Energy Efficiency and Conservation Block Grant Program

The Energy Efficiency and Conservation Block Grant (EECBG) Program provides grants to local governments, tribal governments, states, and U.S. territories to reduce energy use and fossil fuel emissions, and to implement energy efficiency improvements. Through formula and competitive grants, the Program empowers local communities to make strategic investments to meet the nation's long-term goals for energy independence and leadership on climate change.

The EECBG Program is intended to help U.S. cities, counties, states, territories, and Indian tribes to develop, promote, implement, and manage energy efficiency and conservation projects and programs designed to:

- Reduce fossil fuel emissions;
- Reduce the total energy use of the eligible entities;

- Improve energy efficiency in the transportation, building, and other appropriate sectors; and
- Create and retain jobs.

Funding for the EECBG Program under ARRA totals $3.2 billion. Of this amount, approximately $2.7 billion will be awarded through formula grants. In addition, approximately $454 million will be allocated through competitive grants.

All states are eligible to apply for direct formula grants and competitive grants from DOE. Depending on population, cities and counties are eligible for EECBG Program funds either directly from DOE or from the state in which they are located.

To date, DOE has awarded more than 1,200 EECBGs, totaling over $1.4 billion. The first EECBG formula grant awards were made on July 24, 2009, and continue to be made each week.

On October 19, 2009, DOE issued its competitive EECBG funding opportunity announcement. The announcement seeks innovative state and local government and Indian tribe programs, and will use up to $454 million in ARRA EECBG funds for these competitive grants awarded in the two topic areas described below. Applications were due to DOE by December 14, 2009, and the voluntary letters of intent were due by November 19, 2009.

- **Topic 1: Retrofit Ramp-Up, $390 million.** The first topic area will award funds for innovative programs that are structured to provide whole-neighborhood building energy retrofits. These will be projects that demonstrate a sustainable business model for providing cost-effective energy upgrades for a large percentage of the residential, commercial, and public buildings in a specific community. DOE expects to make 8 to 20 awards under this topic area, with award size ranging from $5-75 million. Eligible entities include states, formula-eligible local and tribal governments, entities eligible under Topic 2, and nonprofit organizations authorized by the preceding entities.
- **Topic 2: General Innovation Fund, $64 million.** The second topic area will award up to $64 million to help expand local energy efficiency efforts and reduce energy use in the commercial, residential, transportation, manufacturing, or industrial sectors. DOE expects to make 15 to 60 awards, with award size ranging from $1-5 million. Eligible entities include local and tribal governments that were not eligible to receive population-based formula grant allocations from DOE under the EECBG program; a governmental, quasi-governmental, or non-governmental, nonprofit organization authorized by and on behalf of a unit of local government (or Indian tribe) that was not an eligible entity; or a consortia of units of local governments (or tribes) that were not eligible entities.

For complete details on the availability of funds please visit the EECBG Web site, or the Partnership's funding database.

6.3.7 State Energy Program

The State Energy Program (SEP) provides grants to states to address their energy priorities in the areas of energy efficiency and development of renewable energy technologies. The ARRA appropriated $3.1 billion for the program for fiscal year 2009. In order for a state to be eligible for these funds, it must commit to all three of the following:

- Instituting policies at state-regulated utilities that support energy efficiency;
- Adopting energy efficient building codes; and
- Prioritizing grants toward funding energy efficiency and renewable energy programs.

States will have discretion over how the money is distributed. Local governments and others interested in developing CHP projects should contact their State Energy Office to learn more about their state's process for distributing grants. DOE has posted the list of State Energy Offices. In Maine, SEP funds are directed to Efficiency Maine and starting July 1, 2010 will be directed to the Efficiency Maine Trust.

The Weatherization and Intergovernmental Program in the DOE Office of Energy Efficiency and Renewable Energy manages SEP. More information about SEP can be viewed on the SEP Web site.

6.4 LOAN GUARANTEES

6.4.1 Innovative Energy Efficiency, Renewable Energy, and Advanced Transmission and Distribution Loan Guarantees

The Energy Policy Act of 2005 authorized the U.S. Department of Energy to issue loan guarantees to eligible projects that avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases. The projects need to employ new or significantly improved technologies when compared to technologies in service in the United States at the time the guarantee is issued. Under the solicitation that closed in February 2009, the minimum application fee was $75,000, which indicates that the program has historically been designed to support larger scale renewable energy and bio-fuel projects. DOE periodically publishes requests for applications for loan guarantees, which can target specific technologies or be general.

ARRA expanded the loan guarantee program with $6 billion for renewable energy systems, bio-fuel, and electric power transmission projects. "Renewable energy systems" include those that generate electricity or thermal energy (or manufacture component parts of such systems). Bio-fuel projects are limited to those that are likely to become commercial technologies and will produce transportation fuels that substantially reduce life-cycle greenhouse gas emissions compared to other transportation fuels. The 2009 funds are limited to projects that commence construction by September 30, 2011.

More information about DOE's loan guarantee program, including solicitation announcements, is available on the program's Web site.

6.5 COMMUNITY BASED RENEWABLE ENERGY PILOT PROGRAM

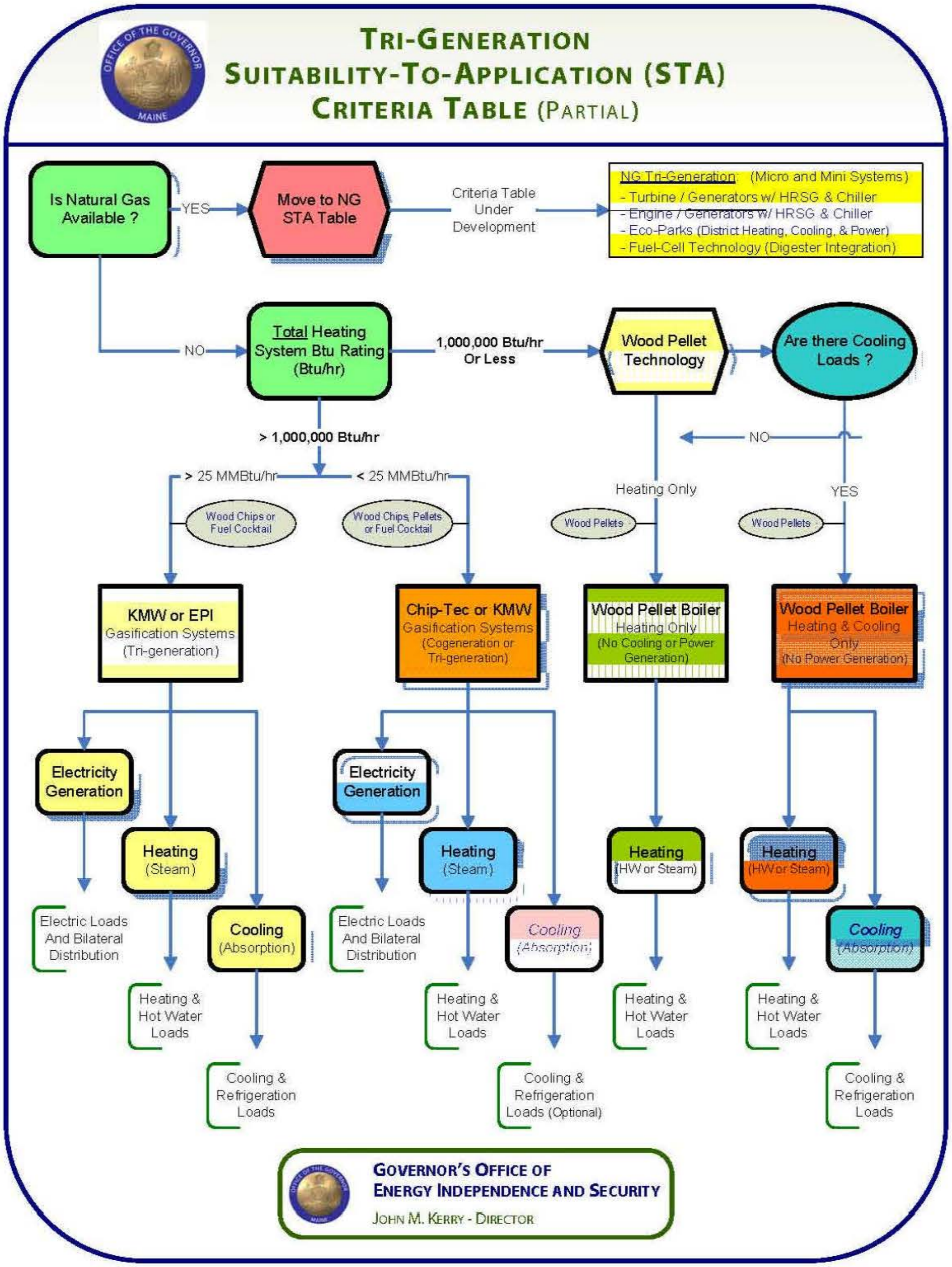
In response to legislative direction, the MPUC established a community-based renewable energy pilot program to encourage the sustainable development of community-based renewable energy in the State. The program is not to exceed 50 megawatts (MW) in capacity and eligible projects must include qualifying owners, community support, grid-connection, and capacity not to exceed 10 MW. One of two incentives can be applied to projects, either long-term contracts or a set renewable energy credit multiplier set at 150% of the amount of the electricity. The State may give purchasing preference to electricity generated by community-based renewable projects, the MPUC can incorporate into the supply of the standard-offer service and shall arrange for a green power offer composed of green power supply and will incorporate green power supply from community-based renewable energy projects to the maximum extent possible.

7. BEST APPLICATIONS IN MAINE

7.1 BEST APPLICATION FOR CHP

As demonstrated in the previous sections in this report, CHP systems have been designed and built for many different applications and various types of facilities, such as commercial applications, hospitals, heath care, education and industrial sites.

In Maine, there are numerous opportunities for CHP application, and many facilities are in various stages of implementing CHP systems. In general terms, the best applications for CHP reside with Energy Eco-Parks, high density housing, health care facilities, hospitals, colleges and universities, food and/or seafood processors, wood product manufacturers, sawmills and any facility or business near natural gas transmission lines. Any facility that has 24/7 operations with heating and cooling needs is perfect for CHP. Facilities with intense thermal loads, such as pulp and paper manufacturers, are also particularly well suited for CHP. Cost-effective and efficient location of CHP at locations with significant thermal loads is encouraged, whether at industrial sites, high-density housing or other facilities. Many facilities and businesses are able to easily take advantage of the environmental and economic benefits that CHP systems offer once an energy model has been created for the site.


TRI-GENERATION
SUITABILITY-TO-APPLICATION (STA)
CRITERIA TABLE (PARTIAL)
Is Natural Gas Available ?
YES
Move to NG STA Table
Criteria Table Under Development
NG Tri-Generation: (Micro and Mini Systems)
- Turbine / Generators w/ HRSG & Chiller
- Engine / Generators w/ HRSG & Chiller
- Eco-Parks (District Heating, Cooling, & Power)
- Fuel-Cell Technology (Digester Integration)
NO
Total Heating System Btu Rating (Btu/hr)
1,000,000 Btu/hr Or Less
Wood Pellet Technology
Are there Cooling Loads ?
> 1,000,000 Btu/hr
> 25 MMBtu/hr
< 25 MMBtu/hr
NO
Heating Only
YES
Wood Chips or Fuel Cocktail
Wood Chips, Pellets or Fuel Cocktail
Wood Pellets
Wood Pellets
KMW or EPI Gasification Systems (Tri-generation)
Chip-Tec or KMW Gasification Systems (Cogeneration or Tri-generation)
Wood Pellet Boiler Heating Only (No Cooling or Power Generation)
Wood Pellet Boiler Heating & Cooling Only (No Power Generation)
Electricity Generation
Heating (Steam)
Cooling (Absorption)
Electric Loads And Bilateral Distribution
Heating & Hot Water Loads
Cooling & Refrigeration Loads
Electricity Generation
Heating (Steam)
Cooling (Absorption)
Electric Loads And Bilateral Distribution
Heating & Hot Water Loads
Cooling & Refrigeration Loads (Optional)
Heating (HW or Steam)
Heating & Hot Water Loads
Heating (HW or Steam)
Cooling (Absorption)
Heating & Hot Water Loads
Cooling & Refrigeration Loads
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TRI-GENERATION SUITABILITY-TO-APPLICATION (STA) DATA TABLE (PARTIAL)

Sample - State System Sizes:

East Campus Capacity:	=	66,782,000 Btu/hr	(3 Boilers Total Capacity)
State House:	=	35,005,600 Btu/hr	(3 Boilers Total Capacity)
Service Garage:	=	2,900,000 Btu/hr	(1 Boiler Total Capacity)
Maine PUC Building:	=	1,089,000 Btu/hr	(1 Boiler Total Capacity)

Note: *Final systems should be sized based on thermal usage profiles, not capacity.*

Basic Conversions:

1 Boiler HP	=	33,465 Btu/hr
1 Boiler HP	=	9.8 $kW_{(Boiler)}$
1 lb Steam	=	1004 Btu
# 2 Fuel Oil	=	139,000 Btu / Gallon
Natural Gas	=	100,000 Btu / Therm.
1 Therm.	=	100,000 Btu
1 kWh	=	3,412 Btu
MMBtu	=	1,000,000 Btu
1 Refrigeration Ton	=	0.58 kW (Consumption)
1 Refrigeration Ton	=	12,000 Btu

Chip-Tec Gasification Systems:

Series A:
12 to 22 Boiler HP = (401,580 Btu/hr to 736,230 Btu/hr)

Series C:
23 to 300 Boiler HP = (769,695 Btu/hr to 10,039,500 Btu/hr)

Series B:
100 to 1,500 Boiler HP = (3,346,500 Btu/hr to 50,197,500 Btu/hr)

KMW Gasification Systems:

Range:
250 to 4,000 Boiler HP = (8,366,250 Btu/hr to 133,860,000 Btu/hr)

EPI Gasification Systems:

Magnitude *(13 MW Biomass Cogeneration or Tri-generation)*:
Up to 40,000 Boiler HP = (up to 1,305,200,000 Btu/hr)

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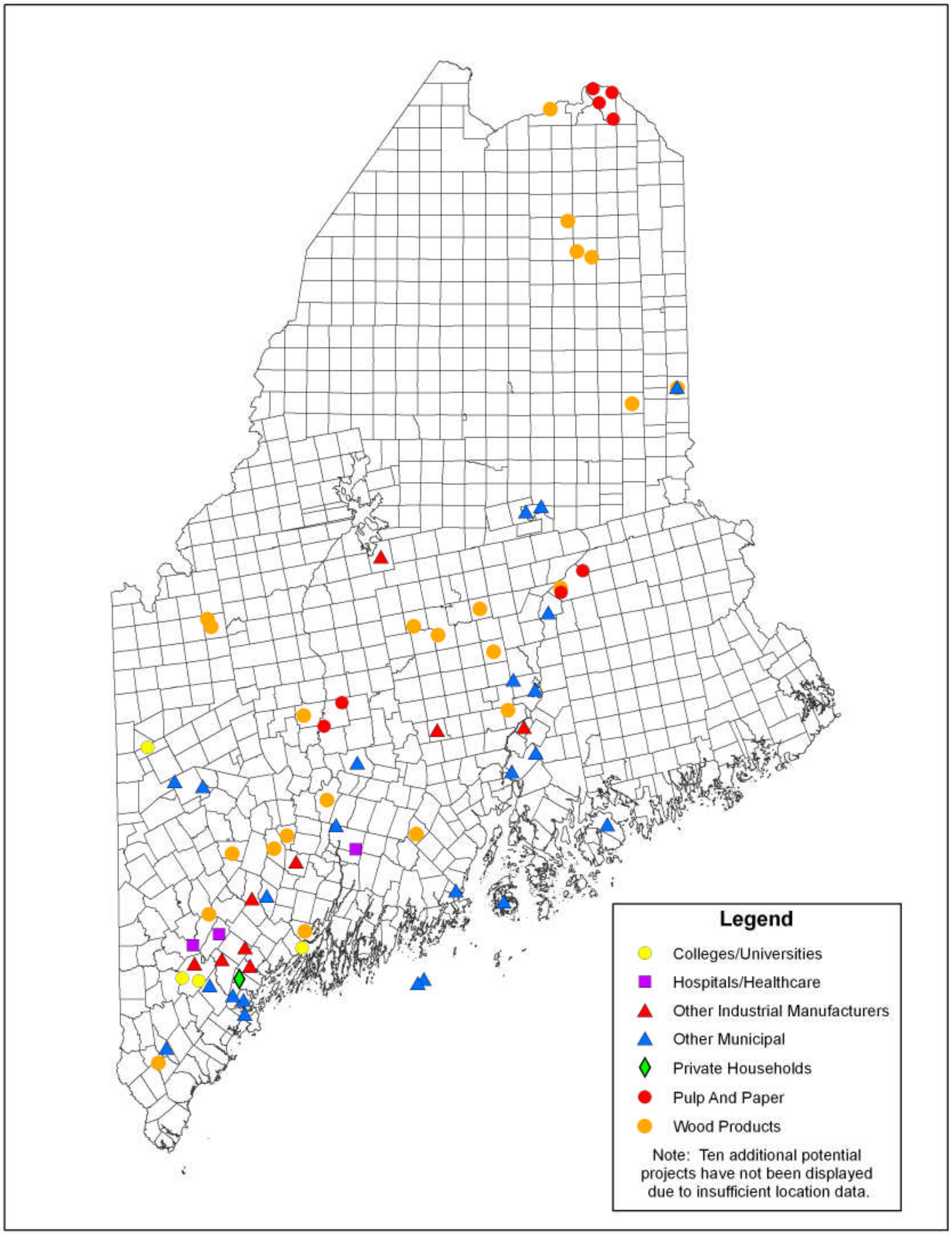
As part of the proposed Maine Energy Independence Fund (MEIF) initiative, OEIS examined potential "shovel-ready" projects throughout Maine that could benefit from positive CHP policies and incentives. OEIS identified more than 60 projects, consisting of a variety of different CHP applications totaling over $750 million.

Figure 7-1 is an illustrative map of potential CHP projects throughout the State of Maine. It does not reflect the full range of projects that may be available, but provides an initial snapshot of the extent to which CHP systems could penetrate the market given favorable incentives and funding opportunities.

Figure 7-1: Map of Shovel Ready Projects in Maine



Source: Map provided by Woodard & Curran

8. POTENTIAL LEGISLATIVE & POLICY RECOMMENDATIONS

Legislative and regulatory policy should recognize the valuable energy, economic development and environmental benefits of CHP and provide a hospitable market for CHP to compete with other energy resources. Maine is already playing an important role through inclusion of CHP as an eligible resource in its renewable portfolio standard and other initiatives. The Maine Legislature and Governor should review and consider the full toolbox of policy options to promote financial and policy incentives for CHP development, including public financing, tax incentives, loan and financing programs, utility and/or regulatory incentives and market-based approaches. CHP is an important part of a comprehensive, integrated energy plan. Policies must be in place to remove barriers to and stimulate CHP projects throughout the state.

OEIS recommends consideration of the following policies, initiatives and action items:

8.1 INTERCONNECTIONS TASKFORCE

In January 2010, the Maine Public Utilities Commission adopted a final rule, Chapter 324 Small Generator Interconnection Procedures, responding to a legislative resolve to "review and make a determination regarding the establishment of statewide standards for the interconnection of small renewable energy facilities to the energy grid." The MPUC concluded that statewide interconnection procedures for Maine's utilities should be created to increase the efficiency of the interconnection process, encourage the increased use of renewable energy and other distributed generation resources like combined heat and power systems and foster a market for companies that sell and install small generation systems.

OEIS commends the MPUC for its rulemaking and recommends that an interconnection stakeholder taskforce be formed to review and further explore how to streamline the technical and economic guidelines or requirements in order to quickly move CHP projects forward throughout the State of Maine.

Standardized interconnection requirements support the development of clean distributed generation by providing clear, concise rules for connecting CHP systems to the utility grid. These rules specify how to purchase power from the grid when supplemental power is needed and sell excess power to the grid. Uniform requirements can ensure that the costs of interconnection are the same throughout the state and are commensurate with the nature, size and scope of the project and that the project interconnection meets the safety and reliability needs of the utility and energy end-user.

The interconnection stakeholder taskforce should include electric utilities, MPUC commissioners, developers of CHP systems and projects, third-party technical organizations, other state agencies (e.g., OEIS), and NGOs.

Areas of exploration and collaboration may include:

- Specific issues faced by different project sizes and types, fuel sources and facilities;
- Appropriate CHP types and technologies;
- Strategies for reducing time and cost of interconnection process;
- Application process, purchase agreements, technical requirements, appropriate fees, insurance, liability issues;
- Existing federal and national organization model rules and requirements and other state experiences;

- Process to monitor effectiveness and ability to update rules; and
- Collaborative process for dispute resolution.

8.2 COST SHIFTING ANALYSIS

There is a concern that different rates and charges may apply to combined heat and power projects to recover utilities' reduced or lost revenue. If customers purchase less electricity due to on-site distributed energy projects, it is possible that utilities will have less income to cover fixed costs and these additional costs could be shifted to other ratepayers. If not properly designed, the additional rates may create unnecessary economic barriers to the use of renewable energy and CHP. Appropriate rate design is critical to ensure utility cost recovery, appropriate price signals for energy efficiency and renewable energy and reasonable and fair prices for rate payers.

OEIS recommends that the MPUC review and further explore cost shifting to ratepayers associated with utilities' potential lost revenue from CHP projects. This analysis should quantify the cost shifting, explore whether these rates and charges are creating unwarranted barriers to the use of renewable CHP projects, examine alternative rate designs and quantify and compare the system-wide benefits that CHP may provide.

A customer who shifts to CHP for the bulk of their electricity needs, but remains connected to transmission and distribution networks and relies upon the T&D network for backup service, should bear its fair share of the utility's costs, but this fair share is often less than 100% of the T&D costs that they would have otherwise paid. The case of Eastern Maine Medical Center demonstrates that "exit fees" or other rate designs that significantly seek to shift T&D rate recovery to allocation based on peak demand, as opposed to volumetric billing, can exert a significant chilling effect on CHP implementation in Maine. To use an analogy, it does not make sense to make a customer pay for a full fare buffet daily when the customer merely needs a snack now and then.

8.3 PURSUE MAINE ENERGY INDEPENDENCE FUND

The Maine Energy Independence Fund (MEIF) is a proposed public-private partnership that would match a potential DOE grant or loan one-to-one with private investments. Funds would be invested in small-to-medium sized clean energy projects and companies located in Maine. These funds would also help with the project development costs. The MEIF would create green jobs in the state, reduce dependence on imported sources of energy and lower energy costs. When fully leveraged with private investments, the MEIF could generate as much as $1 billion of much needed investment in renewable energy and energy efficiency infrastructure in Maine, including CHP projects.

8.4 COGENERATION ENERGY ZONES

The concept of cogeneration energy zones has merit but needs to be characterized. A cogeneration energy zone, as defined in LD 1044, is a "designated geographic area that includes a sawmill that has an on-site cogeneration facility." Deregulation allows CHP models to bilaterally distribute excess electricity supply to remote locations. For example, if Hancock Lumber installed a local CHP faculty in Bethel, any excess electricity from that site could be bi-laterally distributed to their other mills and retail stores in Maine via a wholesale energy account established with ISO-NE. The low-cost electricity supply would help reduce energy costs at the remote sites and the host CHP site in Bethel would realize the benefits of low cost electricity and thermal energy from the CHP plant.

Energy Eco-Parks for sawmill operations could be part of "Cogeneration Energy Zones" for sawmills. Cogeneration Energy Zones could have incentives that help advance CHP models for sawmills, such as streamlining the interconnection process or restricting utility standby fees and/or cost shifting. The energy zones could also benefit from guaranteed cost or access for biomass feedstock sources. Cogeneration Energy Zones could have access to low interest project funding and economic development resources to solicit potential complementary energy eco-park tenants. Hydroponic greenhouse operations or cold storage facilities would offer good year round thermal and electric tenants for such parks. Also, the co-location of bio-fuels production facilities should be considered as 24/7 energy hosts and a fiber enhancement business.

8.5 PLAN TO REDUCE PEAK POWER CONSUMPTION IN GOVERNMENT BUILDINGS

The State of Maine has made significant strides towards reducing the consumption and the cost of energy at the state-owned and operated facilities of executive branch departments and agencies (BGS, Jan. 2010, p. 6). Statewide heating oil use has decreased by an estimated 30% and electricity use decreased by an estimated 5% across these facilities during the FY05 - FY09 period (BGS, Jan. 2010, p. 6). Maine has been using 100% renewable electricity for state facilities since 2007 pursuant to MRSA Title 5, Section 1766-A (BGS, Jan. 2010, p. 4). Energy efficiency, conservation, and independence at the executive branch facilities of state Government can be improved, and the following four points summarize ways in which the State of Maine can reduce peak-load energy consumption in the existing and new state government buildings.

8.5.1 Demand Response Programs

Since the time of the 2007 Resolve, Chapter 183, the State of Maine has entered into a contractual agreement to reduce peak-load energy consumption through a so-called demand response program. Maine's private-sector partner is EnerNOC, which was selected as the result of a public, competitive process. The departments and agencies have pursued demand response programs for both generator and curtailment programs to reduce electricity costs by reducing electricity consumption during peak periods (BGS, Jan. 2010, pp. 11,13). The state through a contract with EnerNOC has enrolled multiple facilities with a total demand response capacity of 2,405 kW. The West Campus of state government in Augusta, which includes the State House, is among the locations enrolled in the demand response program. (BGS, Jan. 2010, p. 60).

In addition, the Department of Corrections, in partnership with BGS, enrolled all of the Department of Corrections facilities with EnerNOC. The program provides revenue to the department for being enrolled in the program and also provides revenue when the department uses its generators in the event that a demanded response event is declared by ISO New England. The revenue will be used to offset utility costs (BGS, Jan. 2010, p. 33).

The BGS Property Management Division, which provides service to 72 buildings within the communities of Augusta, Hallowell, and Vassalboro, is also enrolled with EnerNOC. The program will pay a fee to Property Management to ensure the removal of a given amount of power demand from the grid by running the Burton Cross Office Building generator. In the last three years, Property Management Division has reduced fuel consumption by 8% and electrical consumption by 14% (BGS, Jan. 2010, p. 25).

8.5.2 State Installation of CHP on East Campus

Among state government facilities, the single largest energy consuming location is the East Campus, which is managed by BGS (BGS, Jan. 2010, p. 10). The East Campus consumes approximately 425,000 gallons of heating fuel annually. The major initiative in this area is a plan to install a cogeneration or trigeneration energy system which would capture waste heat to generate electricity. (BGS, Jan. 2010, pp. 10, 60). Several rounds of initial assessment have been completed in the 2007-2009 period and have indicated a combined heat and power application with a fuel source other than oil could payback the initial investment in less than 10 years (BGS, Jan. 2010, p. 60). A substantial and more detailed assessment is expected to be completed for BGS in early 2010 by the firm Harriman Architect + Engineers (BGS, Jan. 2010, p. 60).

8.5.3 Plan Requirements

The following energy reduction goals relevant to state facilities are outlined in the State of Maine Comprehensive Energy Action Plan 2008-2009, promulgated by OEIS (BGS, Jan. 2010, pp. 60-68).

- Work with state government to adopt an overall energy reduction goal at state facilities;
- Work with state government to adopt an overall goal of new, renewable power generation at state facilities;
- Continue to promote increased efficiency standards for all new construction;
- Reduce peak-load energy consumption in all sectors;
- Seek to develop on-site clean, renewable energy projects at appropriate state facilities;
- Assist in the development of "bio-fuel" and "biomass" energy plants using Maine renewable resources;
- Work with DOC regarding biomass and bio-oil refineries using indigenous Maine fiber;
- Increase use of bio-fuels and alternative energy in state-occupied buildings; and
- Continue "lead by example" initiatives in Maine by implementing progressive energy policies applicable to state, county, and local governments.

8.6 EXPAND NATURAL GAS IN MAINE TO HELP REDUCE MAINE DEPENDENCE ON OIL

The Maine Comprehensive Energy Action Plan establishes goals to promote natural gas as a "transitional fuel" by expanding the natural gas infrastructure to all sectors in Maine and supporting development of liquefied natural gas ("LNG") where economically, socially and environmentally feasible. Although natural gas itself is a fossil fuel, it is cleaner-burning and more efficient per btu than fuel oil and coal, and will provide a more environmentally-friendly bridge between Maine's current consumption of fossil fuels and harnessing the state's abundant renewable energy resources. In order to do that, however, projects proposing to increase natural gas availability in Maine must pass the rigorous regulatory and statutory environmental review process exercised by the Department of Environmental Protection. In addition, the support of the community in which such development is proposed is of critical importance.

The Plan recommends convening a year-long, natural gas "dialogue" with all major natural gas players in the state to define the critical challenges regarding the development of traditional natural gas and LNG in Maine and to identify opportunities for the development of traditional natural gas and LNG projects where economically, socially and environmentally feasible. The Plan also recommends facilitating opportunities for private industry and residential customers to connect with natural gas companies in Maine to explore potential natural gas expansion projects.

Natural gas is an important part of the State's energy mix. In order to successfully and cost-effectively upgrade natural gas services, transmission systems and infrastructures, Maine must continue to work with natural gas companies, regulators, potential customers, communities and other stakeholders to explore the development of natural gas policies that support CHP systems in Maine. Natural gas demand is expected to increase and domestic production from conventional natural gas resources in the United States is not expected to keep pace with this projected demand growth. While Maine must focus on cultivating indigenous, renewable resources such as on- and off-shore wind, solar, biomass and bio-fuels, geothermal and tidal energy, it must carefully examine the role of natural gas, including LNG, including its safe and efficient storage and transportation, in the state's immediate and future energy plans.

8.7 SUPPORT CONGRESSIONAL DELEGATION AND ADMINISTRATION ON FEDERAL ENERGY INITIATIVES

The U.S. Congress has made energy and climate change policy development a priority legislative issue. OEIS supports a bipartisan approach to educate, promote awareness of and develop policy on increasing and expanding energy efficiency, renewable energy, natural gas and CHP use in the nation's energy portfolio. For example, the Maine Congressional Delegation should participate in efforts to explore the ways alternative energy sources can help meet Maine's energy needs and reduce the state's dependence on foreign fossil fuels. For example, the Senate and House Natural Gas Caucuses formed in October 2009 to examine the economic, environmental and energy benefits of using domestic sources of natural gas. These types of high-profile, bipartisan groups are also investigating distributed energy, high-performance and sustainable buildings, renewable energy and energy efficiency initiatives. The Maine Governor, Legislature and state agencies should participate in these educational efforts and serve as resources in Congressional hearings, briefings and other legislative forums.

8.8 SUPPORT CURRENT LEGISLATIVE AND REGULATORY ADVOCACY FOR CHP

The CHP community is advocating on the federal and state levels for legislative and regulatory initiatives that will support their industry. On the national level, these efforts include:

- Support to expand the CHP tax credit and extend it until 2016;
- Funding for CHP and waste energy recovery programs within the DOE Industrial Technology Program;
- Inclusion of CHP in a national renewable portfolio standard; and
- Dedicated revenues from climate change legislation to fund CHP, waste energy and district energy projects.

On the state level, CHP advocacy is focused on the following:

- Implementing utility rates to allow for utility cost recovery while also providing appropriate price signals for CHP and other clean energy resources;
- Emission regulations that require air permits to reflect the added value of CHP technologies and to be designed on an output-basis; and
- Standard interconnection regulations.

Increased funding for CHP research, development, demonstration and deployment is critical to incentivize appropriate and cost-effective, environmentally beneficial projects. Funding should be allocated to the most cost-effective projects on a "bang for the buck" basis, measured in terms of grid-purchased kWh avoided or greenhouse gas emissions avoided per public dollar.

In Maine, it has been suggested that the thermal portion of an in-state CHP project should qualify in the RPS and receive renewable energy credit (REC) value in addition to any qualifying (e.g., biomass) generation that is otherwise eligible under the RPS. This change in policy would recognize the full value of CHP projects as a component of the RPS mandate and should be fully explored and modeled as appropriate for Maine.

Maine policymakers should be aware of these activities and support those federal, regional and state initiatives that encourage cost-effective CHP projects in Maine. For example, we support examination of the Northeast CHP Application Center's recommendations for mechanisms that should be considered by New England states:

- Direct funding to provide support for desirable projects.
- Investment Tax Credits (ITC) to encourage capital investment. ITCs may be tied to CHP system efficiency, and states may enact ITCs that are incremental to or separate from Federal provisions.
- Production Tax Credit (PCT) to credit the facility based on energy produced, providing an incentive for reliable operation.
- Development incentives such as tax incentives for Brownfield redevelopment investments or loan guarantees may include CHP.
- Accelerated depreciation or expensing to ease the debt burden and shorten payoff periods. Under Federal rules, depreciation periods depend on what type of business owns the facility (industrial sites typically take depreciation faster than commercial or residential).
- Tax exempt financing or tax exempt leasing to promote investment.
- Loan guarantees to reduce risk to customers installing CHP.
- Emission reduction credits for distributed generation to provide market-based incentives to reduce NOx emissions – credits may be sold in existing emission markets.
- Tariff exemptions from standby or other charges for highly efficient CHP, or other regulatory mechanisms to recognize the system benefits of CHP.

Finally, CHP initiatives should be implemented in synergy with current programs, such as RGGI, and future plans pursued by the Efficiency Maine Trust.

8.9 PURSUE DOE/MAINE MEMORANDUM OF UNDERSTANDING

Maine is seeking to create a partnership with DOE through a Memorandum of Understanding (DOE-Maine Clean Energy and Efficiency Partnership) to:

- Integrate national, regional and state energy, environmental and economic policies;
- Invest in projects in Maine that increase energy efficiency, advance renewable energy, reduce greenhouse gas emissions and promote economic development and jobs;
- Make Maine a replicable model for achievement of a clean-energy-based economy;
- Develop and diversify Maine's economy and energy supply through innovative, market-based mechanisms that allow every sector to benefit from the transition to clean energy; and
- Help Maine create educational and employment opportunities necessary to sustain a clean energy economy.

8.10 IMPLEMENT GRANTS CONNECTOR PROGRAM

ARRA provides Maine with funds for job creation, energy efficiency, renewable energy, weatherization and workforce development. As a response to ARRA, OEIS will be coordinating federal, state and local funding programs with the goal of optimizing energy assistance for Maine businesses, non-profits and government entities. OEIS will track energy efficiency, renewable and clean energy projects in need of assistance and match them with policy, financial and incentive programs, their guidelines and all applicable deadlines. Eligible projects include CHP systems.

8.11 FULLY IMPLEMENT 'AN ACT REGARDING MAINE'S ENERGY FUTURE'

On June 12, 2009, Governor Baldacci signed into law *An Act Regarding Maine's Energy Future* (LD 1485), putting Maine on a path to reduce statewide heating oil consumption 20% by 2020. The legislation establishes the new, independent Efficiency Maine Trust for the purpose of administering programs for energy efficiency and alternative energy resources to help individuals and businesses in Maine "meet their energy needs at the lowest cost." The new Trust will is governed by an independent, nine-member board representing diverse state agencies, customer classes, and environmental interests and is subject to oversight by the MPUC.

The Trust has developed a triennial plan providing program design, planning and implementation strategies for all energy efficiency and alternative energy resources, for all fuel types, across all customer classes. CHP technologies and programs should be a key consideration in the Trust's activities.

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10. ACRONYMS

A

ADSCR- Adjusted Debt Service Coverage Ratio

AFC- alkaline

ARRA- American Recovery and Reinvestment Act

B

BCAP- Biomass Crop Assistance Program

BGS- Bureau of General Services

BHE- Bangor Hydro Electric

C

C-CHP- Combined Cooling Heat and Power

CESCI- Clean Energy Solutions Capital Investment

CHP- Combined Heat and Power

CI- compression-ignition

CMP- Central Maine Power

CO_2- carbon dioxide

CON- Certificate of Need

CREBs- Clean Renewable Energy Bonds

CWSRF- Clean Water State Revolving Fund

D

DG- distributed generation

DOC- Department of Corrections

DOE- Department of Energy

DOER- Department of Energy Resources

DTE- Department of Telecommunications and Energy

DWSRF- Drinking Water State Revolving Fund

E

EAP- Energy Audit Program

ECIPP- Enhanced Commercial/Industrial Performance Program

EECBG-Energy Efficiency and Conservation Block Grant

EIEA- Energy Improvement and Extension Act

EISA-Energy Independence and Security Act

EMMC-Eastern Maine Medical Center

EMS- Energy Management Services

EPA- Environmental Protection Agency

EPACT- Energy Policy Act

EPCA-Energy Policy and Conservation Act

ERC- Energy Resource Commission

F

FERC- Federal Energy Regulatory Commission

G

GCGP- Green Communities Grant Program

GIS- Generation Information System

GWe-gigawatts electric

H

HHV- higher heating value

HRSG-heat recovery steam generator

I

IREC- Interstate Renewable Energy Council

ITC- Investment Tax Credit

K

kW-kilowatt

kWh-kilowatt-hour

L

LHV-lower heating value

LNG-Liquefied Natural Gas

M

MACRS- Modified Accelerated Cost-Recovery System

MADRI- Mid-Atlantic Demand Resources Institute

MCFC-molten carbonate

MEIF- Maine Energy Independence Fund

MNG- Maine Natural Gas

MW- megawatt

N

NECHPI- Northeast Combined Heat and Power Initiative

NECHPRAC- Northeast Combined Heat and Power Regional Application Center

NGOs- non-government organizations

NOx- nitrogen oxide

NYSERDA- New York State Energy Research and Development Authority

O

O&M- Operations and Maintenance

OEIS- Office of Energy Independence and Security

P

PAFC- phosphoric acid

PEMFC- proton exchange membrane

PLRP- Peak Load Reduction Program

PPH- pounds per hours

PTC- Production Tax Credit

PUC- Public Utilities Commission

PURPA- Public Utilities Regulatory Policy Act

Q

QECBs- Qualified Energy Conservation Bonds

R

REC- Renewable Energy Credit

REPI- Renewable Energy Production Incentive

RGGI- Regional Greenhouse Gas Initiative

S

SEP- State Energy Program

SGIP- Small Generator Interconnection Procedure

SI- spark-ignition

SO_2- sulfur dioxide

SOFC- solid oxide

T

T&D- transmissions & distributions

U

USCHPA- United States Clean Heat and Power Association

V

VAMC- Veterans Administration Medical Center

VOCs- volatile organic compounds

W

WWTP- Wastewater Treatment Plant

APPENDIX A: STAKEHOLDER PRESENTATIONS

<u>Overview of Maine Electric Regulations & Policies Affecting Co-generation</u>

Co-generation Task Force Meeting
August 11, 2009
Presented by: Angela Monroe of MPUC

- **Net Energy Billing (co-generation < 660 kW).** (MPUC rule, Chapter 313). Allows netting of generation against usage, carrying excess generation credit over month-to-month for up to 12 months. No payment for excess generation credit at the end of 12 months. Now allows shared ownership with shared netting of generation against owners usage based on each owners' percent ownership.

  Applies to:
  - *Renewables* -- fuel cells, tidal, solar arrays, wind, geothermal, hydro, biomass, municipal solid waste in conjunction with recycling; or

  - "*Micro-Combined Heat and Power Systems*" -- A system that produces heat and electricity from one fuel input (no restriction on type of fuel) and
    - Generation capacity 1kW – 30kW, fuel system efficiency not less than 80% in production of heat & electricity; or
    - Generation capacity 31kW – 660 kW, fuel system efficiency not less than 65% in production of heat & electricity;
    - May work in combination with supplemental or parallel conventional heating systems;
    - Is manufactured, installed and operated in accordance with applicable government and industry standards; and
    - Is connected to the electric grid and operated in conjunction with the facilities of a T&D utility.

- **Small Generator Aggregations (generation 5 MW or less).** (MRSA 35-A § 3210-A)
  - For all fuel sources, requires standard-offer provider to purchase output at real-time price to keep payment neutral to standard offer provider. Prices are, therefore, not known ahead of time. The T&D to administer purchase & sale. There is an administrative fee for this.

  - For renewable fuel or "efficient combined heat and power system," allows T&D to administer purchase and sale with any competitive electricity provider, not just standard offer provider. Efficient combined heat and power system same definition as "micro-combined heat and power systems" without upper 660 kW limit.
    - Note: the rulemaking for the CEP purchase portion not yet done. Legislation indicates that the rulemaking may include a fee to cover the T&D utilities' cost of administration.

- **Small Power Producer or Cogenerator.** (MRSA 35-A §3305). Allows small power producers or cogenerators to "generate or distribute electricity through his private property solely for his own use, the use of his tenants or the use of, or sale to, his associates in a small power production or cogeneration facility and not for the use of or sale to others without approval or regulation by the commission."

    - "*Co-generator*" means municipality or person that generates electricity and steam or other useful forms of energy that are used for commercial, industrial, heating or cooling purposes; and that is not primarily engaged in the generation or sale of electricity other than that generated at the cogeneration facility.

    - "*Small power producer*" means a municipality or person owning or operating a power production facility that does not exceed 80 MW that depends upon renewable resources for its primary source of energy.

- **Sale and Distribution to Other Entities.** In 2000-653 (Boralex Case) the Commission found that under certain conditions, the distribution and sale of electricity by a generator (regardless of size or fuel type) is a "private," not a "public," sale and therefore does not make the generator a T&D utility or a CEP. The Commission found that factors in this determination include:

    - Whether both generator and customer are on the same or adjacent properties;
    - Whether the generator and customer have a corporate or commercial relationship that goes beyond the sale of electricity;
    - Whether the number of customers served or that could be served is limited;
    - Whether all the power sold comes from the generator as opposed to the grid;
    - Whether there are no sham transactions to create a private character;

    Note: In some cases, this might implicate provisions of MPUC Rule, Chapter 395. Chapter 395 allows private ownership of distribution facilities if the facilities serve only one customer but requires transfer to the T&D utility if more than one customer is to be served. Therefore, an entity seeking to serve more than one customer from a privately-owned distribution facility might need to seek a waiver of those provisions of Chapter 395.

In order to distribute power to a customer (or customers) without meeting the criteria of either 35-A §3305 or the Boralex decision, a generator would need to be licensed by the MPUC as a T&D utility and a CEP. The CEP license is a relatively straight-forward process. Becoming licensed as a T&D utility, however, would require a finding by the MPUC that the incumbent utility was either unable or unwilling to provide service.

- **Renewable Portfolio Standards (RPS).** (MPUC rule, Chapter 311). For every kWh sold in Maine, 30% is required to come from an "eligible" resource (Type II resource) and starting January 1, 2008, another 1% (increasing 1% each year to the maximum of 10% by 2017) from a "new renewable" resource (Type I resource).

    - *Eligible Type II* resources must either be from an "efficient" resource or from a renewable fuel source;
        - Efficient resource must have been constructed prior to 1997;
        - Renewable resource must not exceed 100 MW and relies on fuel cells, tidal power, solar arrays, wind, geothermal, hydro, biomass, or municipal solid waste in conjunction with recycling.

    - *Eligible Type I* resources must be fueled by a renewable resource (excludes municipal solid waste and requires fish passages for hydro), not exceed more than 100 MW (except wind) and:
        - Have been added to an existing facility after September 1, 2005;
        - Have not operated for at least two consecutive years or was not recognized by the ISO-NE or NMISA as a capacity resource prior to September 1, 2005, and, after September 1, 2005, resumed operation or was recognized by the ISO-NE or NMISA or as a capacity resource; or
        - Have been refurbished after September 1, 2005 and are operating beyond their previous useful life or employing an alternate technology that significantly increases the efficiency of the generation process.

- **Also of Note:**

    - Stand-by rates. Utilities have various rate schedules for customers that self-generate electricity but purchase electricity when their generator is unavailable;

    - Special rate contracts. Utilities often enter discount rate contracts to discourage customers from self-generating. Availability likely to decrease as stranded-costs continue to decline.

Governor's Office of Energy Independence and Security

Combined Heat and Power Stakeholder Group

August 11, 2009

William Weber, P.E. Principal Engineer
wjweber@mactec.com
www.mactec.com

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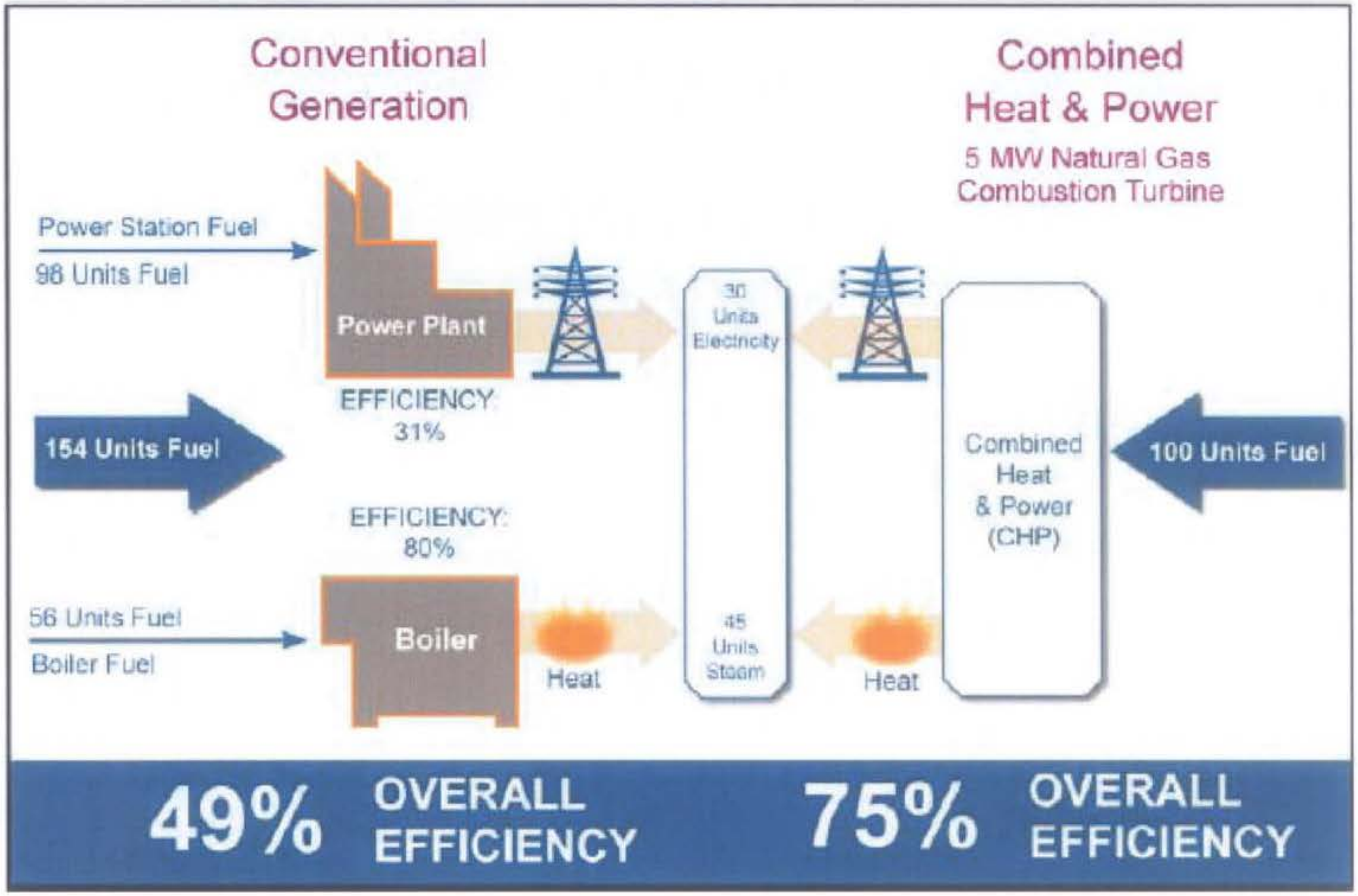
Small Scale Cogeneration

- Applications
- Technologies
- Example Projects
- Comments and Questions

Advantages of Combined Heat and Power (CHP) over Central Power Generating Station



Ref. EPA CHP Partnership

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Small Cogeneration Applications

- Small CHP or CCHP 1 MW and smaller
- Simultaneous Demand for Heating, Cooling and Power
  - Commercial Applications
  - Hospitality
  - Heath Care
  - Education
  - Industry

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Small Cogeneration Technologies

- Reciprocating Engines
- Microturbines
- Fuel Cells
- Micro CHP

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Reciprocating Engines

- Gas and Diesel Engines
- Diesel Engines limited to Emergency Standby Power due to air emissions
- Generally higher maintenance cost than gas turbines
- Available in size 10kW to over 5 MW

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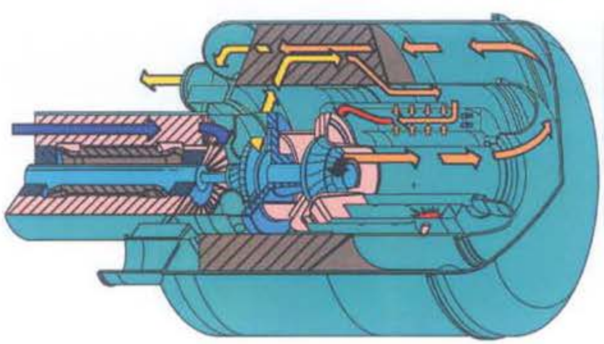
Microturbines

- Compact Gas Turbine
- NG, biogas, distillate oil, propane
- Extremely low emissions
- Modular can be ganged with absorption chiller for CCHP



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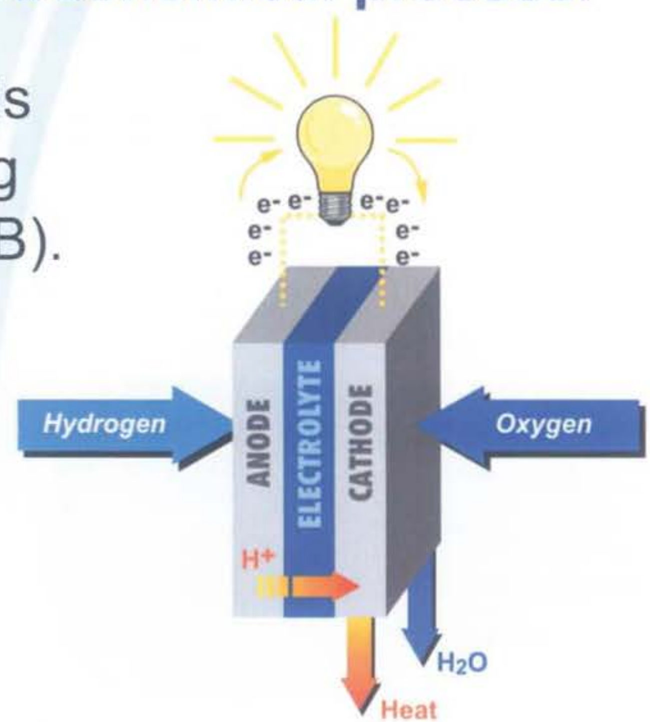
Fuel Cell

- Fuel Cells produce **electricity and heat without combustion** or moving parts. Uses hydrogen (or a hydrogen-rich fuel) and oxygen to create electricity by an **electrochemical process.**
- Meet or exceed air emission standards throughout the United States including California Air Resources Board (CARB).
- **Extremely quiet** operation



Anode: $2H_2 \rightarrow 4H^+ + 4e^-$

Cathode: $O_2 + 4H^+ + 4e^- \rightarrow H_2O$

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Fuel Cell

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Small Cogeneration Technologies

Technology	Recip Engine	Microturbine	Fuel Cell
Efficiency	70 - 80 %	65 – 75 %	55 – 85 %
Typical Capacity	.01 – 5 MW	30 – 250 kW	5 – 400 kW
Installed Cost	\$1000 - \$2200 / kW	\$2000 - \$3000 / kW	\$3500 - \$6500 / kW
Fuel	NG, LFG, Biogas	NG, Biogas, Fuel Oil	NG, H2, Propane
Availability	92 – 97 %	90 – 98 %	> 95 %
Noise	High	Moderate	Low
Emissions	Moderate	Low	Low

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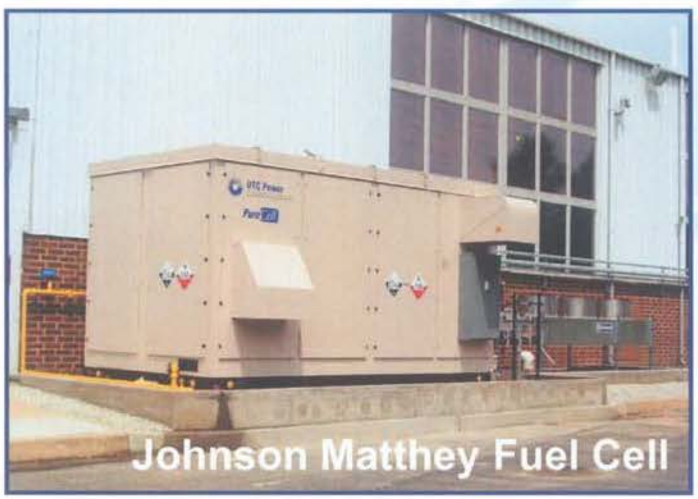
MACTEC CCHP Project Examples

- Johnson Matthey Industrial, 200 KW Fuel Cell
- St. Helena Hospital, 400 KW Fuel Cell
- Whole Foods, 200 KW Fuel Cell - several locations
- Clarkson University, three 65 KW Microturbines
- Current TV,123 Townsend Ave, Microturbines
- Ritz Carlton, San Francisco, Microturbines



Johnson Matthey Fuel Cell

Microturbines

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Clarkson University Microturbines

- 3 Microturbines and Absorption Chiller
- Provides 195 kW power to new LEED Silver Technology Advancement Center (TAC)
- Simultaneous chilled water and hot water for space heating/cooling and domestic hot water requirements

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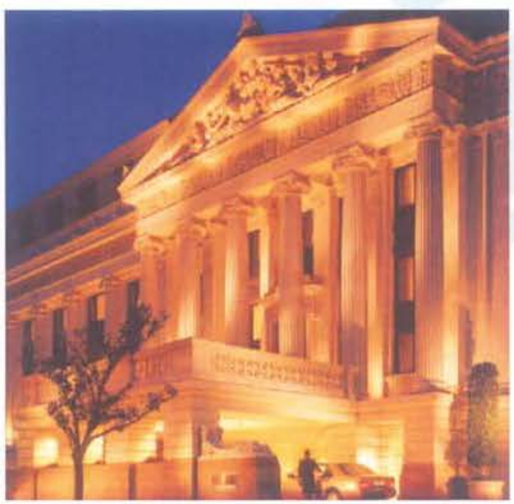
Ritz Carlton Microturbines

- 336 Room Luxury Hotel in San Francisco
- Combined Cooling, Heating and Power (CCHP)
- Four 60kW Microturbines with double effect absorption chiller
- 160 Tons of cooling



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Whole Foods Fuel Cell

- Combined Cooling, Heating and Power 46,000 sf facility
- 200 kW Fuel Cell meets 100 % of electricity and 50% heating demand

- Partially funded by State (Conn Clean Energy Fund)

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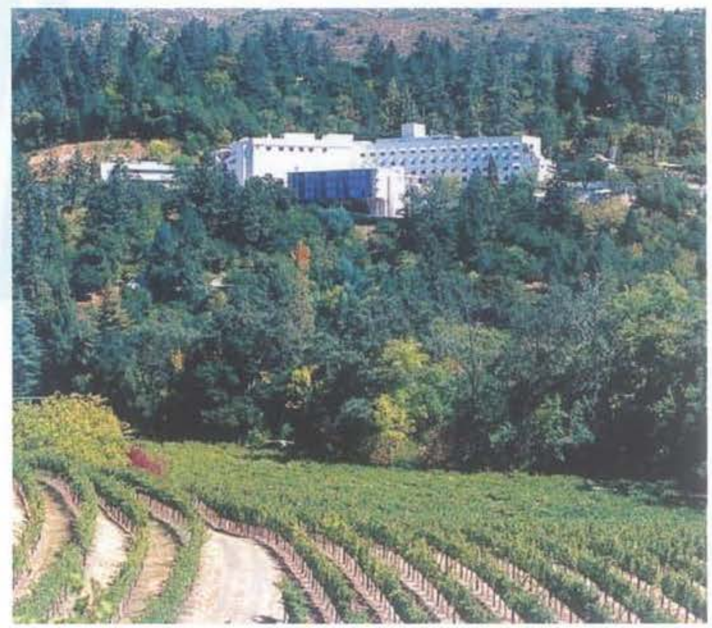
St Helena Hospital Fuel Cell

- 181 Bed Full Service Hospital
- 400 kW Fuel Cell with 1700 KBtu/Hr of Hot Water used for space heating
- Partially funded by State (CSGIP)



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Micro - CHP

- Residential Use
- Up to 5 kW
- Base load for most homes 1kW
- Propane or Natural Gas
- Integrated Inverter
- Installed Cost over $13,000

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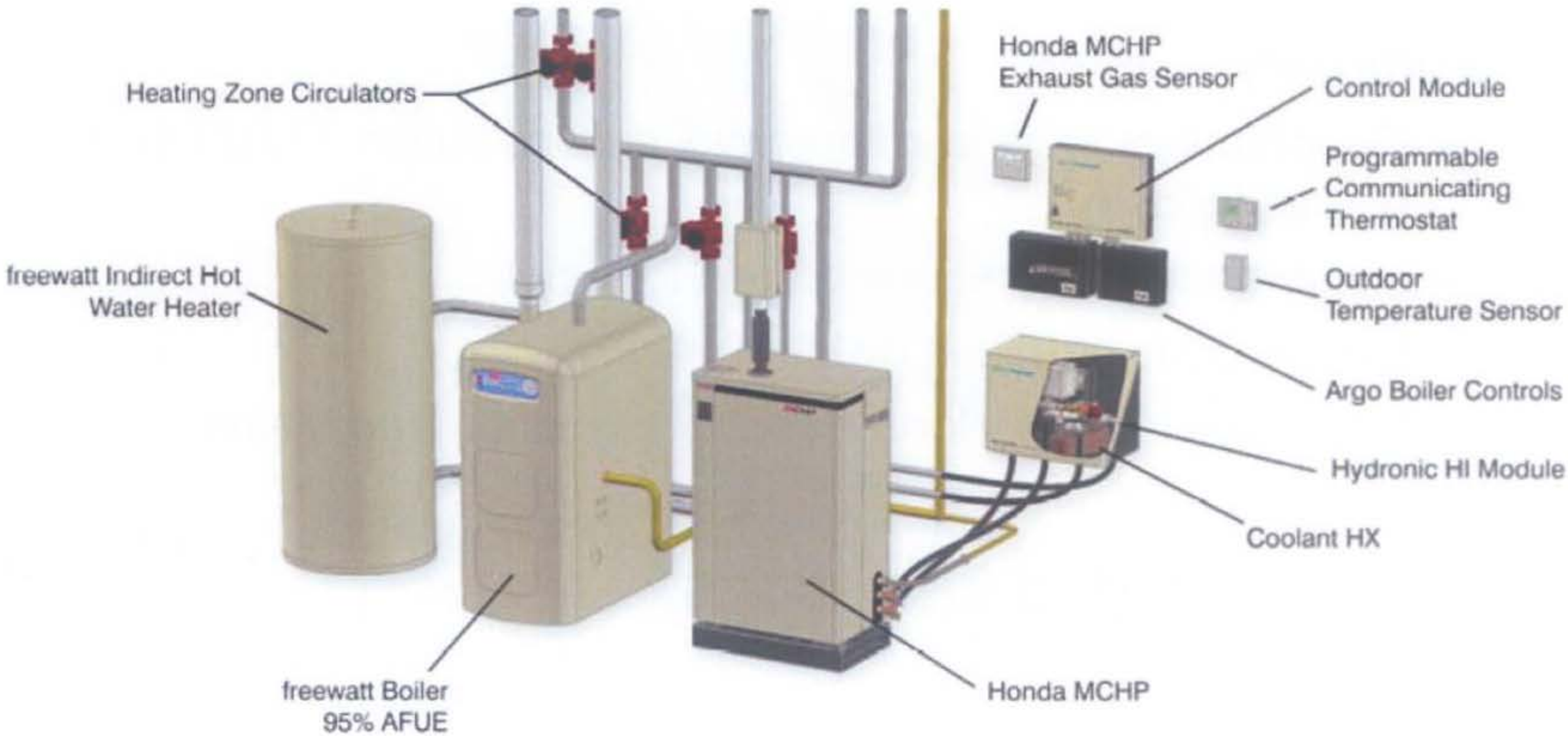
Micro – CHP Honda Freewatt



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Small Scale Cogeneration

- Summary
  - Opportunities exist at commercial and institutional facilities as well as industry
  - Cogeneration will reduce carbon footprint
  - Limited by natural gas distribution
  - Incentives in other North East states higher than Maine

- Comments and Questions

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CHP
EPA COMBINED HEAT AND POWER PARTNERSHIP
Producing Reliable Energy & Preserving the Environment

Overview - Medium to Large CHP Technologies

OFFICE OF THE GOVERNOR
MAINE

Governor's Office of Energy Independence & Security (OEIS)

Combined Heat & Power Taskforce

August 11th, 2009

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CHP Technology Sizes

- **CHP – Combined Heat & Power:**

CHP Technologies can be divided into three size categories (CHP plants not merchant power plants).

Small: 5 to 1,000 kWe (single or multiple units)

Medium: 1,000 to 10,000 kWe (single or multiple units)

Large: 10,000 to 50,000+ kWe (single or multiple units)

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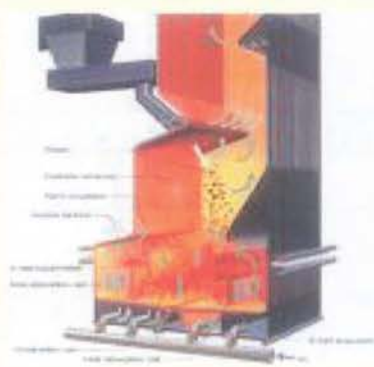
CHP Technology - Fuel Sources

<u>Fuel Sources for **Medium** to **Large** CHP Systems:</u>

- Natural Gas
- Liquefied Natural Gas
- Bio-gas (syngas - landfill, digester, sludge, …)
- Bio-mass (woody, agricultural, opportunity fuels, …)
- Liquid Biofuels (Bio-Oil, Bio-Butanol, etc.)
- Conditioned Construction & Demolition Waste
- Coal
- Municipal Solid Waste (MSW)
- TDF – Tire Derived Fuel

CHP Energy Conversion Technologies

- Combustion Turbines
- Combustion Engines
- Fuel Cells
- Anaerobic Digesters
- Fixed Bed Boilers
- Fluidized Bed Boilers
- Gasifiers



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Combustion Turbine / Generators

- <u>Combustion Turbines / Generators (CTG)</u>:

Combustion Turbines are much like jet aircraft engines coupled to an electric generator. C/T/G's can utilize many fuels defined for CHP technologies. High temperature exhaust gases from the turbine are captured and used to generator steam in an exhaust gas heat recovery steam generator (boiler or HRSG). This steam can be used for thermal energy needs of the host or even for additional power generation via a steam/turbine/generator. This is a called combined cycle energy model.

Courtesy of Siemens Westinghouse

Combustion Turbine / Generators

- <u>Medium Size – Combustion Turbine/Generator</u>:

  This size CHP system is typical from 1,000 kW to 10,000 kW with the median size about 5,000 kW. Eastern Maine Medical Center's system is about 5,000 kW. These system can produce from 8,900 to 47,000 pph of steam with a median output of 25,000 pph. A median size hospital uses about 30,000 pph of steam.

- <u>Large Size – Combustion Turbine/Generator</u>:

  This size CHP system is typical from 10,000 kW to 50,000 kW with the median size about 25,000 kW. One of the turbines at Verso Paper Jay Mill Cogen is 50,000 kW. These systems can produce from 47,000 to 340,000 pph of steam with a median output of 180,000 pph.

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Combustion Engine / Generators

- **Medium Size – Combustion Engine/Generator:**

  This size CHP system is typical from 1,000 kW to 8,000 kW with the median size about 3,000 kW. Eastern Maine Medical Center's system is about 5,000 kW. These system can produce from 1,800 to 20,000 pph of steam with a median output of 10,000 pph.

- **Large Size – Combustion Engine / Generator:**

  Typically Engine/Generators are not used in this category and not available. There are very large engines employed for other uses like peaking merchant power plants where multiple engine/generators are combined for peaking power generation needs but not for CHP.

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Combustion Engine / Generators

- <u>Combustion Engine / Generators (CEG)</u>:

  Combustion Engines are much like a car or tractor engine coupled to an electric generator. C/E/G's can utilize many fuels defined for CHP technologies. Thermal energy from high temperature exhaust, jacket water and lube oil coolers is recovered from the engine and used to generator steam in an exhaust gas heat recovery steam generator (boiler or HRSG). This steam can be used for thermal energy needs of the host or even for additional power generation via a steam / turbine / generator. This is a called combined cycle energy model.

Combustion Engine / Generators

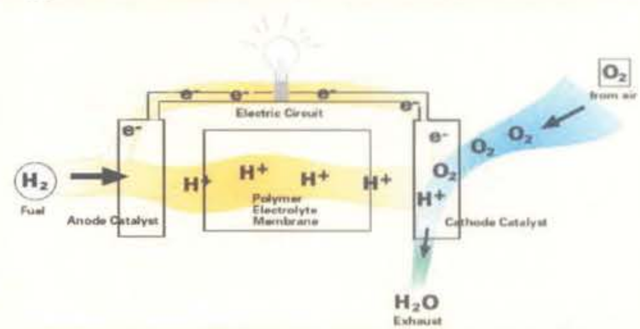
- Combustion Engine / Generators (CEG):

Combustion Engine/generators have greater flexibility than combustion turbine/generators since they have a greater turn down for matching swings in thermal loads however their thermal energy recovery is lower than combustion turbine/generators. Suitability to application is on of the core design criteria when considering CHP technologies for each end user.

Fuel Cells

- <u>Fuel Cells</u>:

  Fuel cell systems produce energy different from traditional prime mover technologies. Fuel cells are similar to batteries in that both produce a direct current (DC) through an electrochemical process without direct combustion of a fuel source. However, whereas a battery delivers power from a finite amount of stored energy, fuel cells can operate indefinitely provided the availability of a continuous fuel source. Two electrodes (a cathode and anode) pass charged ions in an electrolyte to generate electricity and heat. A catalyst enhances this process.



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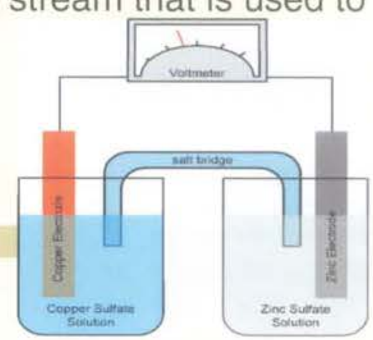
Fuel Cells - Types

There are five types of fuel cells under development.

These are: 1) phosphoric acid (PAFC), 2) proton exchange membrane (PEMFC), 3) molten carbonate (MCFC), 4) solid oxide (SOFC), and 5) alkaline (AFC). The electrolyte and operating temperatures distinguish each type. Operating temperatures range from near ambient to 1,800°F, and electrical generating efficiencies range from 30 to over 50% HHV. As a result, they can have different performance characteristics, advantages and limitations, and therefore will be suited to distributed generation applications in a variety of approaches.[1]

The different fuel cell types share certain important characteristics. First, fuel cells are not Carnot cycle (thermal energy based) engines. Instead, they use an electrochemical or battery-like process to convert the chemical energy of hydrogen into water and electricity and can achieve high electrical efficiencies. The second shared feature is that they use **hydrogen** as their fuel, which is typically derived from a hydrocarbon fuel such as **natural gas**. Third, each fuel cell system is composed of three primary subsystems: 1) the fuel cell stack that generates direct current electricity; 2) the fuel processor that converts the natural gas into a hydrogen-rich feed stream; and 3) the power conditioner that processes the electric energy into alternating current or regulated direct current. Finally, all types of fuel cells have low emissions profiles. This is because the only combustion processes are the reforming of natural gas or other fuels to produce hydrogen and the burning of a low energy hydrogen exhaust stream that is used to provide heat to the fuel processor. [1]

[1] From EPA CHP Technologies Catalog

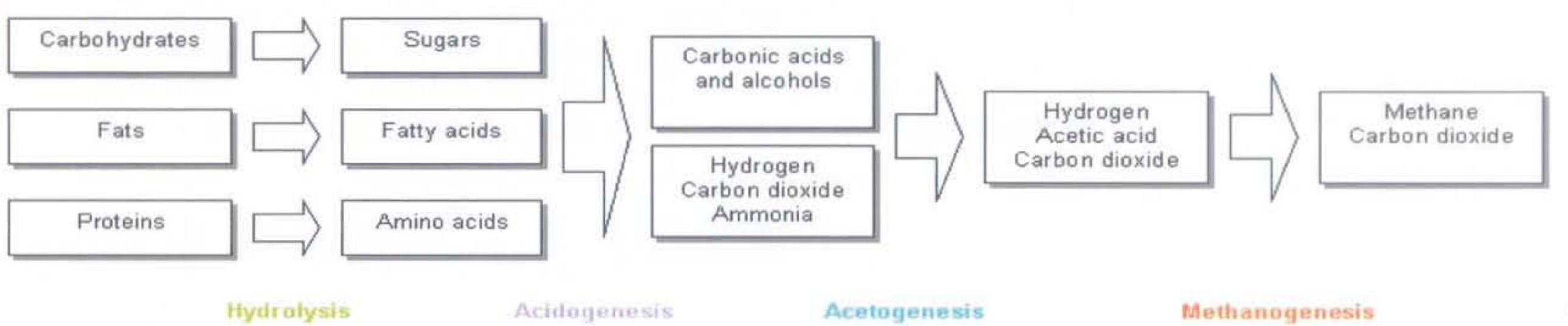


Anaerobic Digesters

Anaerobic Digesters:

Anaerobic digesters breakdown biodegradable materials in the absence of oxygen. A resultant biogas is produced containing methane gas, this gas is used to create energy. Some applications of anaerobic digesters include wastewater sludge, agricultural waste, and animal waste. The solids byproduct can be used as a fertilizer.

This source of fuel can be used in Medium Size CHP applications where the methane source is adequate to produce 1,000 kWe are greater in electrical / thermal energy.



Fixed Bed Boilers

- <u>Fixed Bed Boilers</u>:

  Fixed bed boilers are the most common type biomass boiler for CHP applications for large systems but are being replaced by gasification technologies in the medium size to large size systems. Fixed bed (stoker) boiler use direct fire combustion of solid fuels with excess air producing a hot flue gas to create steam which is in turn used to generate electricity with a steam turbine generator. Excess steam is then used for process thermal energy or heating based on the site specific energy balance. Many fixed bed boilers have been enhanced with over-fire air and under-fire air systems to improve complete combustion. Many lumber mills in Maine utilize medium sized systems and most paper mills have at least one large biomass boiler, typically a fixed bed system with moving grate. Some mills have large continuous fluidized bed biomass boilers.

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Fluidized Bed Boilers

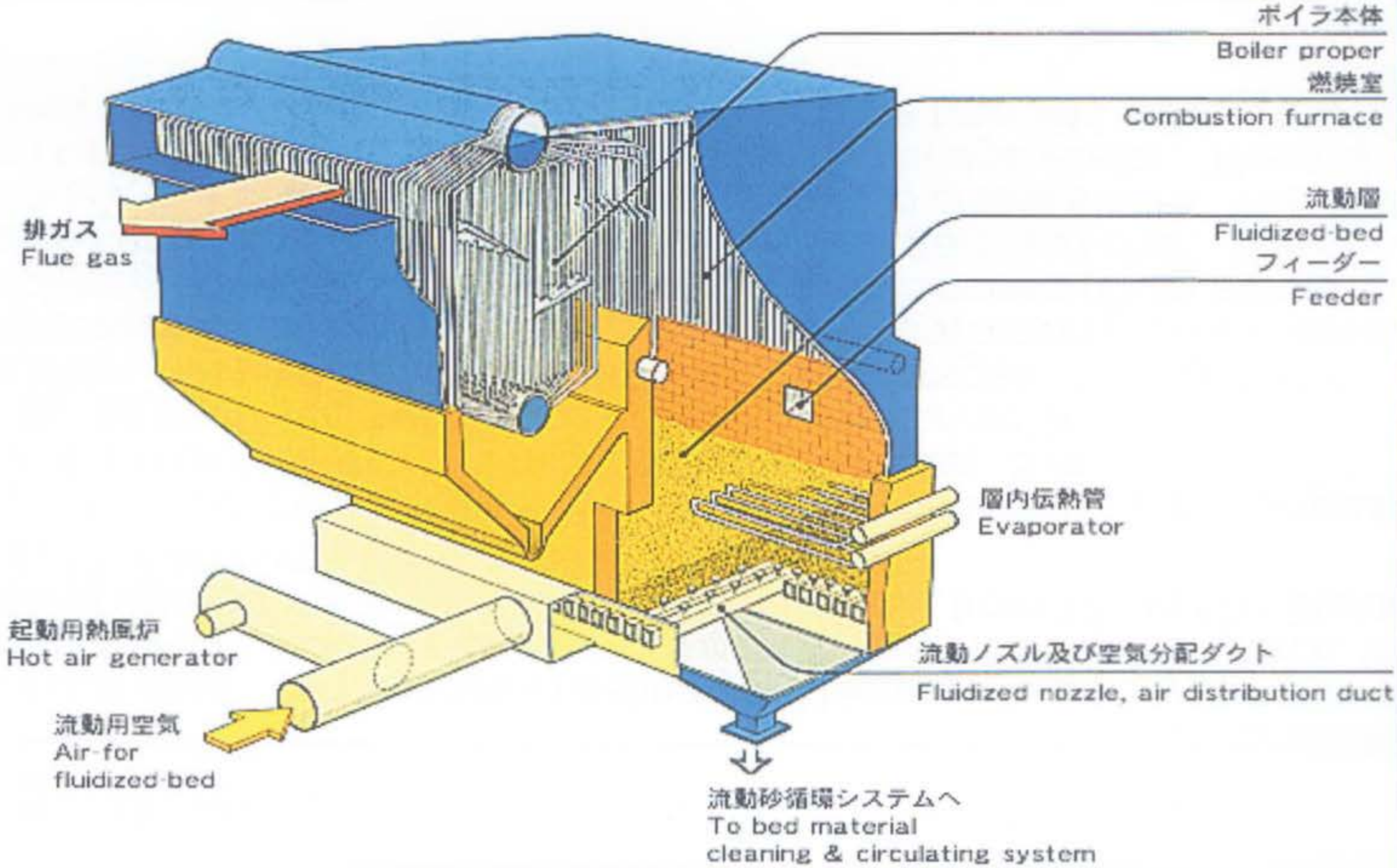
Fluidized bed boilers are employed for the high range of the medium size systems and are typical for the large size systems. Fluidized bed boilers will combust many opportunity fuels that are blended with traditional biomass.

In this method of combustion, fuel is burned in a bed of hot inert, or incombustible, particles suspended by an upward flow of combustion air that is injected from the bottom of the combustor to keep the bed in a floating or "fluidized" state. The scrubbing action of the bed material on the fuel enhances the combustion process by stripping away the CO_2 and solids residue (char) that normally forms around the fuel particles.

This process allows oxygen to reach the combustible material more readily and increases the rate and efficiency of the combustion process. One advantage of mixing in the fluidized bed is that it allows a more compact design than in conventional water tube boiler designs. Natural gas or fuel oil can also be used as a start-up fuel to preheat the fluidized bed or as an auxiliary fuel when additional heat is required. The effective mixing of the bed makes fluidized bed boilers well-suited to burn solid refuse, wood waste, waste coals, and other nonstandard fuels.[1]

[1] EPA Biomass CHP Technology Catalog

Fluidized Bed Boiler - Diagram



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Gasifiers

Biomass gasification involves heating solid biomass in an oxygen-starved environment to produce a syngas. Depending on the biomass source, the heating value of the syngas, can range anywhere from 100 to 500 Btu/cubic foot (10 to 50 percent that of natural gas).

The fuel output from the gasification process is generally called ***syngas***, though in common usage it might be called ***biogas***. Syngas can be produced through direct heating in an oxygen-starved environment, partial oxidation, or indirect heating in the absence of oxygen. Most gasification processes include several steps. The primary conversion process, called pyrolysis, is the thermal decomposition of solid biomass (in an oxygen-starved environment) to produce gases, liquids (tar), and char. The gasifier is couple to a boiler where the syngas is used to create steam. The steam is then used to create electricity with a steam/turbine/generator. Thermal energy is also utilized in the CHP model and the type and volume are defined in the site specific energy balance.

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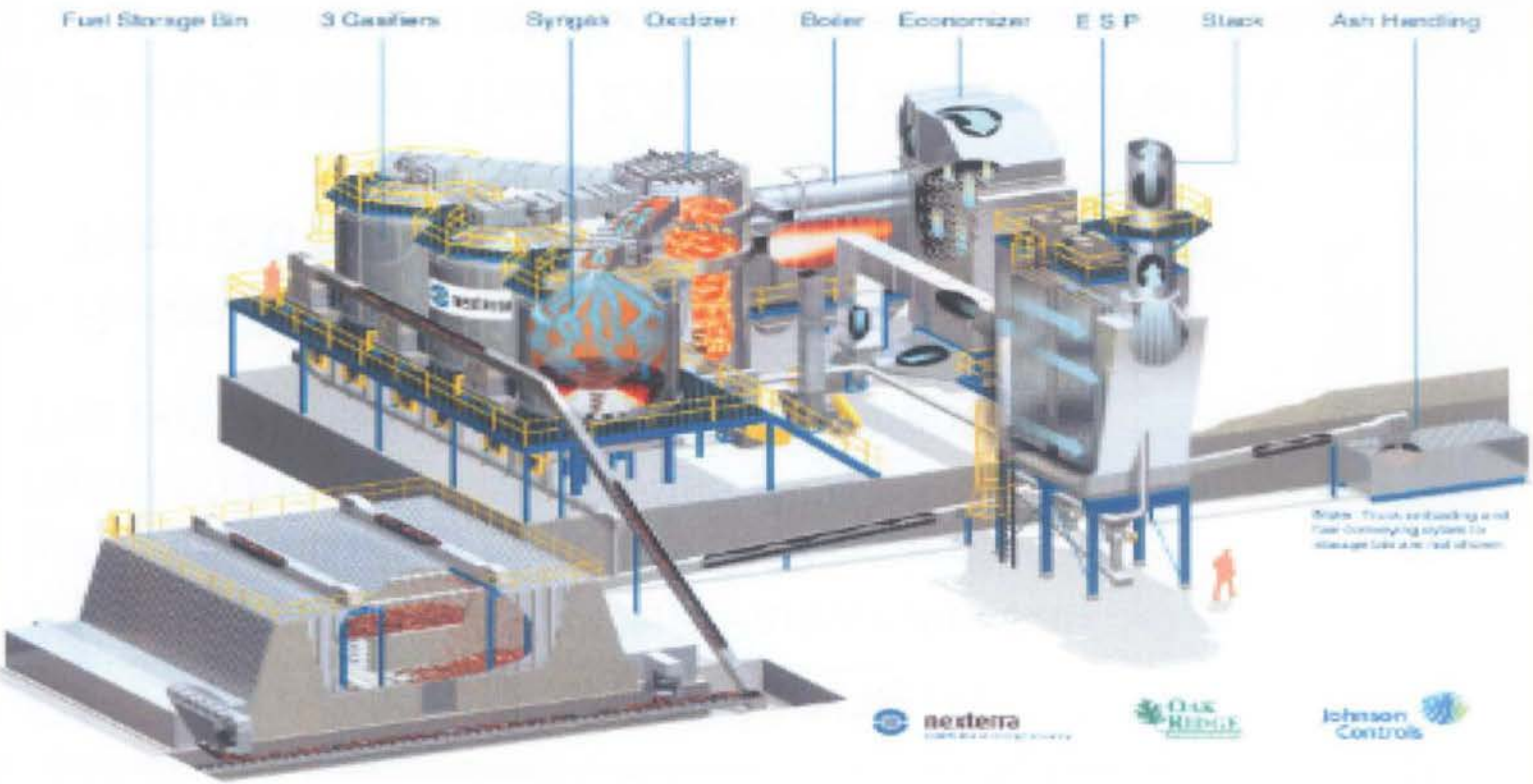
Gasifier - Example



Nexterra Biomass Gasification for Johnson Controls at DOE's Oak Ridge National Laboratory (ORNL) in Tennessee.

CHP Emissions

CHP
EPA COMBINED HEAT AND POWER PARTNERSHIP
Producing Reliable Energy & Preserving the Environment

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(C-CHP Combined Cooling, Heating and Power)

- **CHP Environmental Benefits:**

Through 2007, the EPA CHP Partnership has helped install more than 335 CHP projects, representing 4,450 megawatts (MW) of capacity. The emissions reductions are equivalent to:

A. Removing the Annual Emissions of More Than **2.0** Million Automobiles.

OR

B. Planting More Than **2.4** Million Acres of Forest.

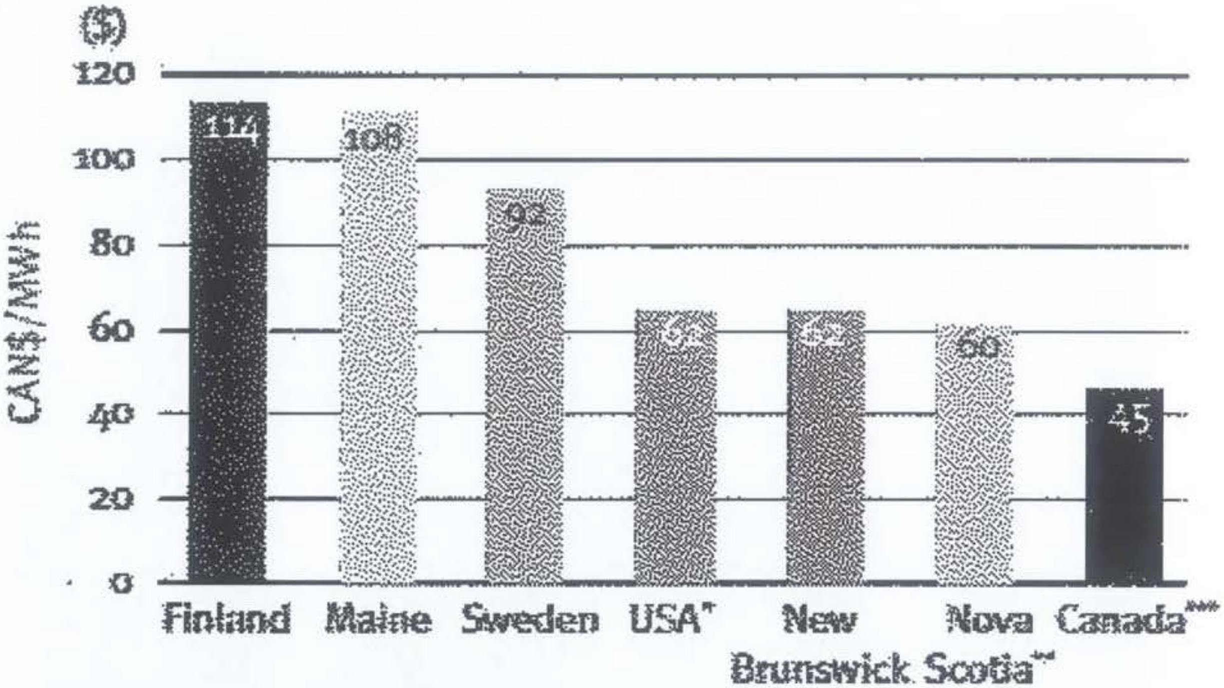
25% Less Emissions with Cogen/Tri-Gen Energy Models

Source: www.epa.gov/chp/

Biomass Electricity

- Eight existing "stand alone" biomass facilities
- About 265 MW of baseload renewable energy
- ~3.5 million green tons of annual wood use
- Support from regional RPS standards
- A number of forest industries have biomass boilers as well

Chart 13: Average Industrial Electricity Rates



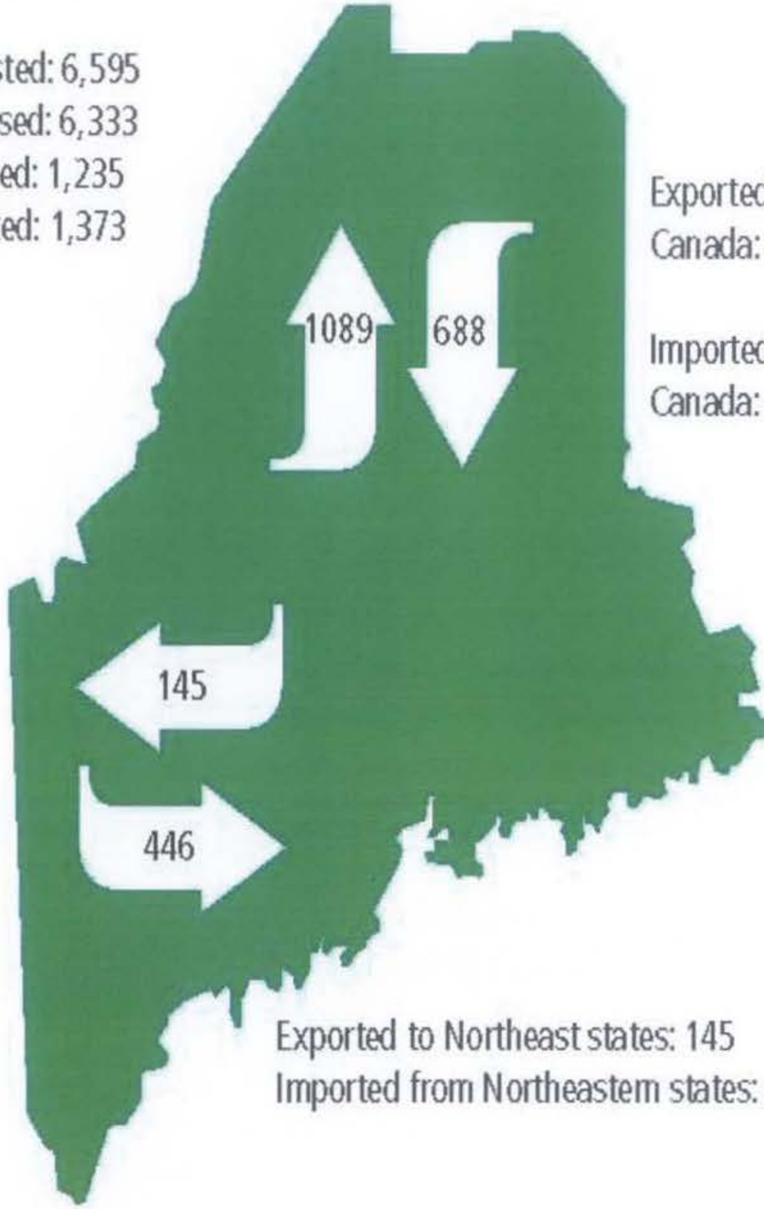
* Average of 22 "forest intensive" states
** Reflects confirmed rate offered to the Port Hawksbury paper mill
*** Average of 6 "forest intensive" provinces

Source: Competitive Energy for New Brunswick Forest Industry – Stantec Consulting

Maine 2005

All units are in 1000 cords

Harvested: 6,595
Processed: 6,333
Exported: 1,235
Imported: 1,373



Exported to Canada: 1,089

Imported from Canada: 688

Exported to Northeast states: 145
Imported from Northeastern states: 446

Eastern Maine Medical Center
Combined Heat and Power Project

Presented to The Combined Heat and Power Task Force September 17, 2009

Presented by Jeff Mylen, PE, MS, Director of Construction Services, EMMC

EASTERN MAINE MEDICAL CENTER
The Right Choice, Right in the Heart of Maine

CIANBRO

Vanderweil Engineers

OAK RIDGE NATIONAL LABORATORY

Solar Turbines
A Caterpillar Company

INTERNATIONAL DISTRICT ENERGY ASSOCIATION

Eastern Maine Medical Center Combined Heat and Power Project

Highlights & Talking Points

- 1995 – 1997 EMMC started looking into turbine technology for the campus.
- 1998 (January) The ice storm reinforced the fact that hospitals need dependable electrical power.
- 2000 – 2001 EMMC started working with Vanderweil Engineers (Boston) to look at the feasibility of using turbine technology on this campus.
- 2003 Vanderweil updated their 2001 study to include the new load profile of the medical center and newer technology of the turbine.
- 2003 (fall) EMMC applied for a Department of Energy grant to help finance the turbine project.
- 2004 (May) EMMC was awarded a $3 million dollar Department of Energy award (administrated by Oak Ridge National Lab) to build and operate a CHP Plant.
- 2005 (February 4) EMMC was awarded a Certificate of Need by the State of Maine to start construction of CHP Plant.
- 2005 (July) EMMC began formal construction of the CHP Plant.
- 2006 (October 16) The CHP plant at EMMC was fully tested and online.

Eastern Maine Medical Center Combined Heat and Power Project

- **EMMC CHP Facts & Figures**
- The generator connected to the turbine generator is 4.6 Megawatts, which is equal to supplying electricity to 46,000 one hundred watt bulbs, or approximately 400 average size homes.
- Eastern Maine Medical Center will stay connected to the Bangor Hydro Grid and still import approximately 20% of its electricity from the street on an annual basis.
- The cost of the project was approximately 8.2 million dollars. EMMC's cost was approximately 5.2 million dollars (minus the 3 million dollar award).
- The expected energy savings per year will be approximately 1 million dollars (plus) per year, yielding a pay back less than 5 years.
- The heat output of the Heat Recovery Steam Generator (boiler) is equivalent to heating approximately 300 homes.
- During the summer months, surplus steam from the plant can be used to help cool the hospital by utilizing a new 500 ton steam absorption chiller and two new cooling towers. This output is equivalent to helping cool approximately 500 homes on a hot day.

Eastern Maine Medical Center Combined Heat and Power Project

- EMMC Facility Overview
  - Critical Regional Tertiary Hospital
- Existing Utilities and Infrastructure
  - Duel fuel high pressure steam boiler plant and distribution system
  - 2300 ton electric chilled water plant
  - Two (2) 12.4 KV feeders on overhead poles from BHE with primary switchgear and site distribution
  - Two (2) 1500 KW diesel emergency gen sets & (1) 500 KW

Eastern Maine Medical Center
Combined Heat and Power Project

- Existing Energy Consumption Key Figures

Electric Power	Steam
28.0 million KWH purchased annually	117,000 MLB steam produced annually
5300 KWD peak demand	42,000 PPH peak steam demand
$3.3 million annual electric cost	1,000,000 gallon of NO2 fuel consumed annually
$0.15 average cost per KWH (04-05) $0.17 cost currently without CoGen	$1.55 - $1.65 per gallon of NO2 fuel oil in 2004-2005 Higher costs presently

Eastern Maine Medical Center Combined Heat and Power Project

- CHP Project History at EMMC
- Project Implementation Approach
  - Design/Build Project Team with Cianbro Corp. & Vanderweil Engineers
  - Values and benefits of the Project team
- Explored alternative financing methods for the $8.2 million project and considered:
  - Internally financed project
  - Third party built, own and operate
  - Third party capital lease
- Applied for the DOE's Distributed Energy System Application and was successful in obtaining a $3,000,000 award and balance will be internally financed

Eastern Maine Medical Center
Combined Heat and Power Project

- Why EMMC was a good application for CHP
  - High Utility Rates
  - High Process Thermal Load
  - 12 Month thermal requirement for heating or cooling
  - Match between Electric and Thermal Loads
  - 24 Hour Seven Day a Week Operation
  - High Pressure Natural Gas Availability-no compressor needed
  - Operations and Departments with Critical Load Requirements
  - Attractive ROI and Annual Operating Cost Savings

Eastern Maine Medical Center Combined Heat and Power Project

- Project Approval Process
  - Internal - Board of Director's Approval
  - External - Certificate of Need (CON) Process
  - Air Permit Application
  - City and local permits

Eastern Maine Medical Center Combined Heat and Power Project

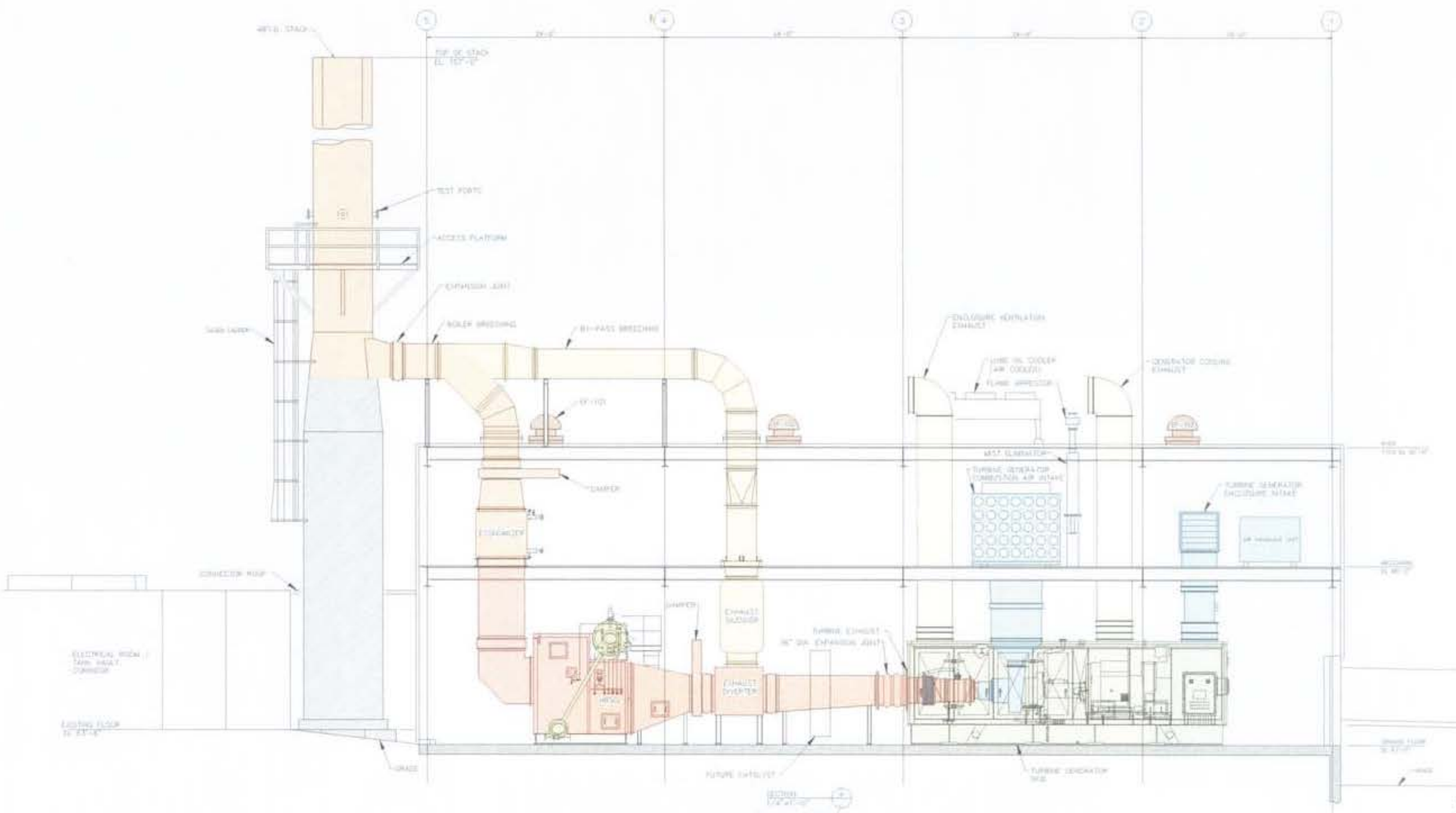
- System Configurations based on:
  - Solar Centaur 50, 4.6 Mwe @ ISO with un-fired HRSG generating 25,000 PPH steam
  - New 500 ton steam absorption chiller and ancillaries
- CHP projected key financial figures:
  - $5.2 million project net capital cost (factoring out Department of Energy Award ($3 million)
  - $700K to $800K operating cost savings (net cash flow)

Eastern Maine Medical Center
Combined Heat and Power Project

Utility Interconnection Issues & Lessons Learned

- Get the electric utility involved early.
- Clearly identify how you want your control scheme to operate within the utility parameters.
- Complete comprehensive front-end analysis and resolution of utility tie connections to existing plant
- Planning, communication, and implementation between the engineer and field technicians is vital, especially for the electrical synchronizing to the utility.

Eastern Maine Medical Center
Combined Heat and Power Project



Eastern Maine Medical Center Combined Heat and Power Project

Overview

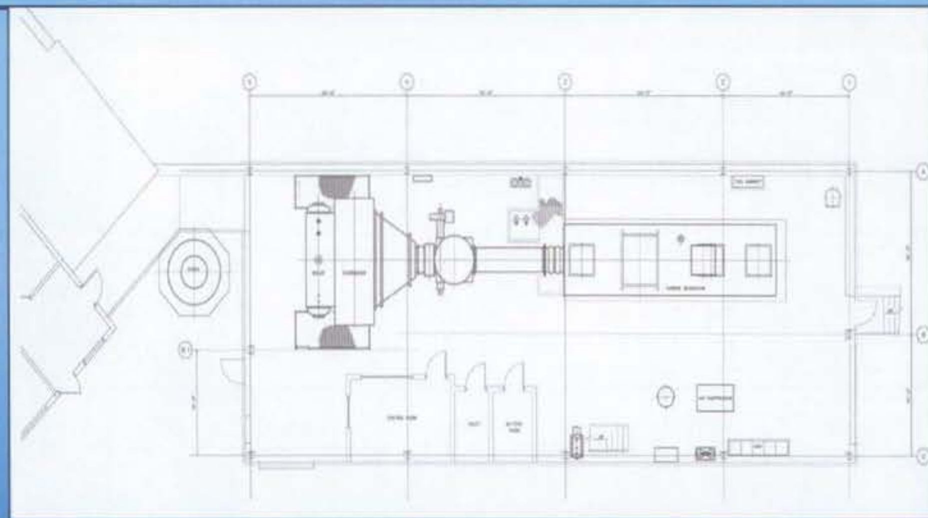
- Critical Regional Tertiary Hospital
- Duel fuel high pressure steam boiler plant and distribution system
- 2300 ton electric chilled water plant
- Two (2) 12.4 KV feeders on primary switchgear and site
- distribution
- Two (2) 1500 KW + 1- 500 KW emergency generators

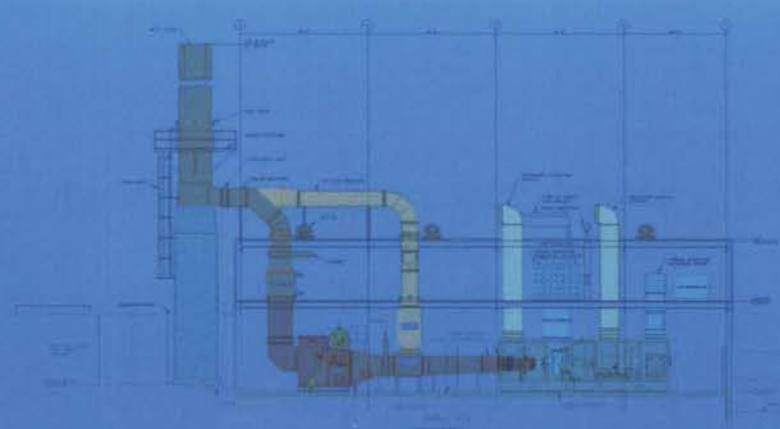
Project Overview

- High Energy Costs
- Fuel Use Diversity
- Need for additional chilled water capacity
- Need to deliver services under any climatic condition
- Utility Reliability
- Diverse thermal heating load profile
- Emissions compliance

Objectives

- Design a system that responds to a specific energy concern for healthcare – reliability
- Use an integrated, modular "power island" concept to reduce field labor costs and installation time, while increasing the opportunity for replication
- Design a system that could be replicated for similar applications with a minimal amount of balance of plant and integration costs
- Structure the CHP system using advanced information technology to aid in information dissemination





Electric Power	Steam
28 million KWH purchased annually	117,000 MLB steam produced annually
5300 KWD peak demand	42,000 PPH peak steam demand
$3.3 million annual electric cost	1,000,000 gallon of No. 2 fuel consumed annually
$0.15 average cost per KWH in 2004-2005	$1.55-$1.65 per gallon of No. 2 fuel in 2004-2005

CHP System Configuration

- Solar Centaur 50, 4.6 Mwe @ ISO Conditions
- Un-fired HRSG generating 25,000 PPH steam
- New 500 ton steam absorption chiller

Benefits

- Reduced Emissions
- Increased thermal and heating capacity and enhanced emergency backup power
- Savings will directly reduce healthcare costs
- Power availability during adverse weather conditions

Solar Turbines
A Caterpillar Company

INTERNATIONAL DISTRICT ENERGY ASSOCIATION

Vanderweil Engineers

CIANBRO

OAK RIDGE NATIONAL LABORATORY

EASTERN MAINE MEDICAL CENTER

Eastern Maine Medical Center
Combined Heat and Power Project

Utilities Cost Comparison at FY2007 Demand

Projected utility Costs		With CoGen		
	$6,044,914.37	$4,681,177.12	savings	$1,363,737.25

Utilities Cost Comparison at FY2008 Demand

Projected utility Costs		With CoGen		
	$6,720,009.77	$4,774,263.72	savings	$1,945,746.05

Utilities Cost Comparison at FY2009 Demand

Projected utility Costs		With CoGen		
	$2,061,709.80	$1,600,142.97	savings	$ 461,566.83

Year to date

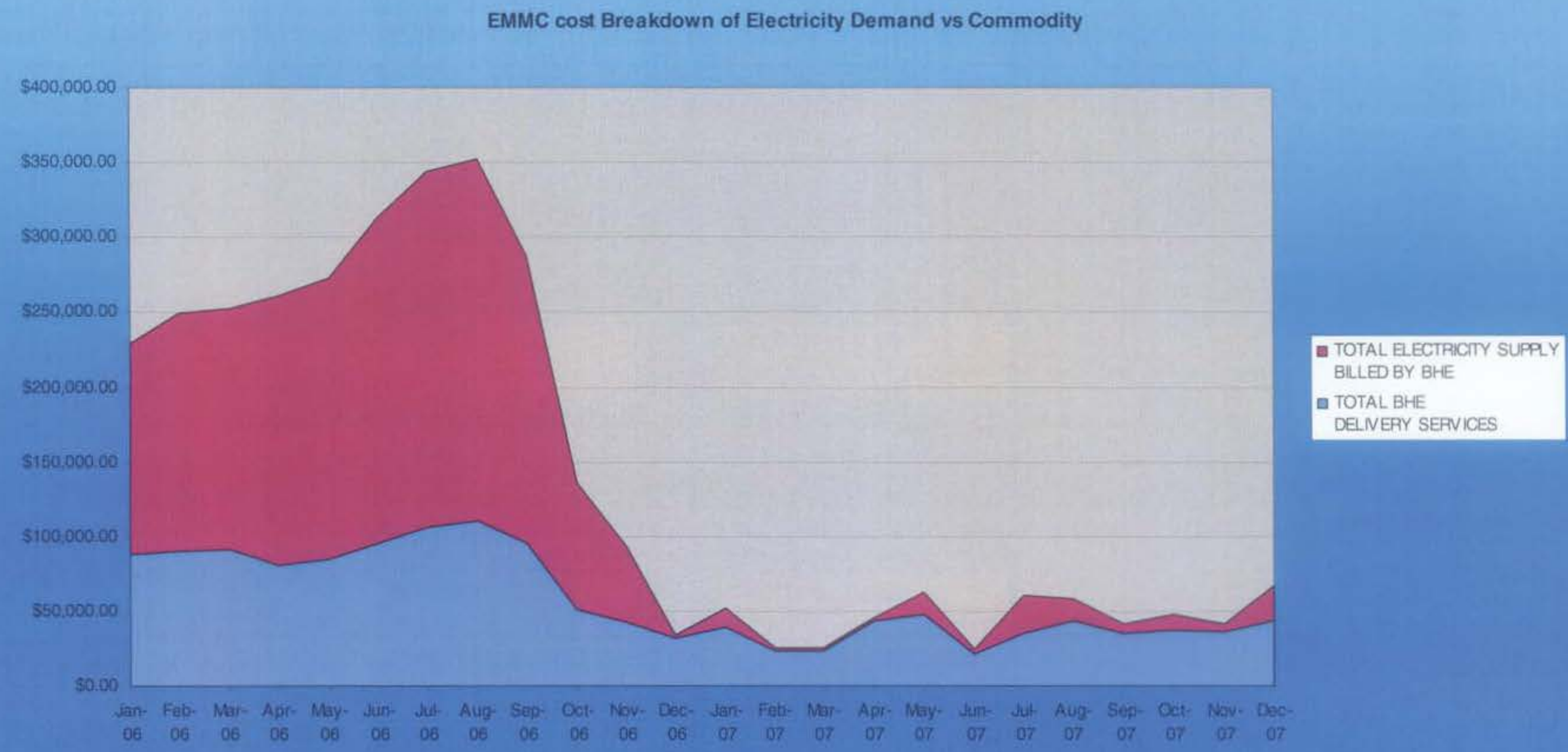
Oct 06- Jan-09

Total Savings to date

$3,771,050.13

Note: Projected costs are based on actual Bangor Hydro rate structure

Eastern Maine Medical Center Combined Heat and Power Project



Eastern Maine Medical Center Combined Heat and Power Project

Eastern Maine Medical Center
Combined Heat and Power Project

Eastern Maine Medical Center Combined Heat and Power Project

- Resources to help you evaluate whether CoGen is for you:

http://www.ornl.gov/sci/engineering_science_technology/cooling_heating_power/

http://www.emmccogen.org

Any specific CoGen questions please feel free to contact me @ jmylen@emh.org

Presentation to the Combined Heat and Power Task Force
Impact of Self-Generation on Utilities and Utility Customers
September 17, 2009

For the record, I'm David Allen, and I represent CMP at the legislature. I'd like to thank the Task Force for the opportunity to present a utility perspective to the discussions we're having regarding the opportunities that combined heat and power technologies present to a wide variety of customers.

I've been asked to provide a utility's perspective in three areas, interconnections, standby charges, and the impact of lost load on other customers. In all three areas, the company's position is fairly simple and straightforward. Customer-installed generation should not be allowed to impact other customers either electrically or financially.

Interconnections are governed by federal standards at the transmission level and by MPUC standards at the distribution level. The three issues that must be addressed are safety, reliability and costs. Naturally, any generation at a customer's site must be safely installed in order to protect that customer, neighboring customers, anyone who works on the system and the system itself. Safety standards are pretty straightforward, though occasionally there are disputes about how robust safety measures should be for a given system.

System reliability is an important issue for the company and its customers, especially as more and more intermittent resources are put on the system. If a customer is taking power from the system and suddenly starts putting power out onto the system, fluctuations in voltage are bound to occur, and sometimes other customers on the same circuit are impacted. Equipment can be installed to minimize voltage fluctuations, but that equipment can be costly.

That brings us to the issue of interconnection costs. Anytime significant generation is added to a distribution circuit, a system impact study should be done to see if the circuit can handle the generation and what protections may need to be installed. Safety equipment is added to protect people and the system as a matter of course, and that equipment must be tested periodically. In addition, special metering is usually needed and must be installed on larger facilities. All of those costs should be borne by the customer installing the generation and not shifted to other customers.

The next issue is the most contentious, and that's so-called standby charges. If someone builds a new facility and installs generation without being hooked up to the grid, there is no impact on the utility or other customers. In all other cases, whether a customer disconnects completely or continues to stay hooked to the grid, other customers are affected financially. In other words, whenever a current customer adds his own generation, other customers will end up paying more, because a large portion of a utility's costs are fixed.

In most cases, customers installing generation choose to stay hooked to the grid, and the question becomes, how much should they pay for that service. The customer would say, "I should only have to pay for T&D service when I need it." The utility would say that the customer should pay the costs of providing standby service to that customer based on the maximum demand he could place on the system at any one time. That's what the utility has to plan for.

That's because the company has to build and maintain the lines and pay all the ancillary and back office costs for that customer, including reserving space on the transmission system, whether the customer uses the system or not. If that customer does not pay those costs, then all other customers will pay them.

Here are a few examples of T&D revenue savings for hypothetical customers in different customer classes using current standby rate methodology. In each case those revenue savings become costs to other customers. In other words, the T&D savings for the generating customer are paid for by other utility customers.

Size of generator	Normal T&D revenues	Self generator T&D revenues*
5 MW	$859,633	$76,068
660 kw	$104,152	$9715
300 kw	$40,978	$3684

*All of these numbers assume that a combined heat/power plant runs 80% of the time (many run at higher numbers), and that the customer uses the grid one month each year.

The examples I've just given should give the task force and idea of how self-generation impacts other customers. How self-generation impacts the company depends greatly on what customer class the generator is in. At the residential level, the basic charge is about $9.00/month, even though the average cost to serve a residential customer is about $35/month. We collect money from residential customers based on how much power they use, so other residential customers pick up a substantial amount of that cost.

Our largest customers pay based on their **demand,** that is, the most power used in any 15 minute period in any month, and pay very little per kwh. The cost shifting by larger customers is based on how much demand they have, not how much power they use.

I stopped the examples at 5 MW, because once you get over that size, other market rules come into play.

Finally, CMP opposed one of the bills that engendered this task force, LD 1044 for a variety of reasons, but basically because of the cost shifting that would ensue. We estimated that one generator of the size mentioned in the bill would cause other customers to see rate increases to make up about $1.65 million in lost T&D revenue. In other words if one sawmill took advantage of the bill, other sawmills would see their rates increase.

In general, we oppose shifting costs from one group of customers to other customers.

I'd be happy to answer any questions you might have.

Maine IOU Rate Components and Projections of Stranded Costs as of September, 2009

Co-generation Task Force Meeting
September 17, 2009
Provided by Angela Monroe, MPUC

Rates as of 9/17/09

CMP (¢/kWh)

	Residential/ Small Commercial	Medium	Large (Distr. Voltage)	Large (Trans. Voltage)	Weighted Avg.
Distribution	4.38	1.33	0.96	0.06	2.70
Stranded Cost	0.29	0.39	0.45	0.21	0.33
Conservation & Solar Assess	0.15	0.15	0.15	0.005	0.14
Transmission	1.54	1.47	1.34	1.24	1.47
Total Delivery	6.37	3.35	2.90	1.51	4.64
Standard Offer	8.92	6.76	6.92	6.92	7.90
Total Rates	15.29	10.11	9.82	8.43	12.53

BHE (¢/kWh)

	Residential/ Small Commercial	Medium	Large (Distr. Voltage)	Large (Trans. Voltage)	Weighted Avg.
Distribution	5.36	2.46	1.47	0.26	3.50
Stranded Cost	1.04	0.96	0.86	0.94	0.99
Conservation & Solar Assess	0.15	0.15	0.15	0.005	0.13
Transmission	1.73	1.84	1.51	1.64	1.73
Total Delivery	8.28	5.40	3.98	2.84	6.34
Standard Offer	9.00	6.88	8.29	8.29	8.23
Total Rates	17.28	12.28	12.27	11.13	14.58

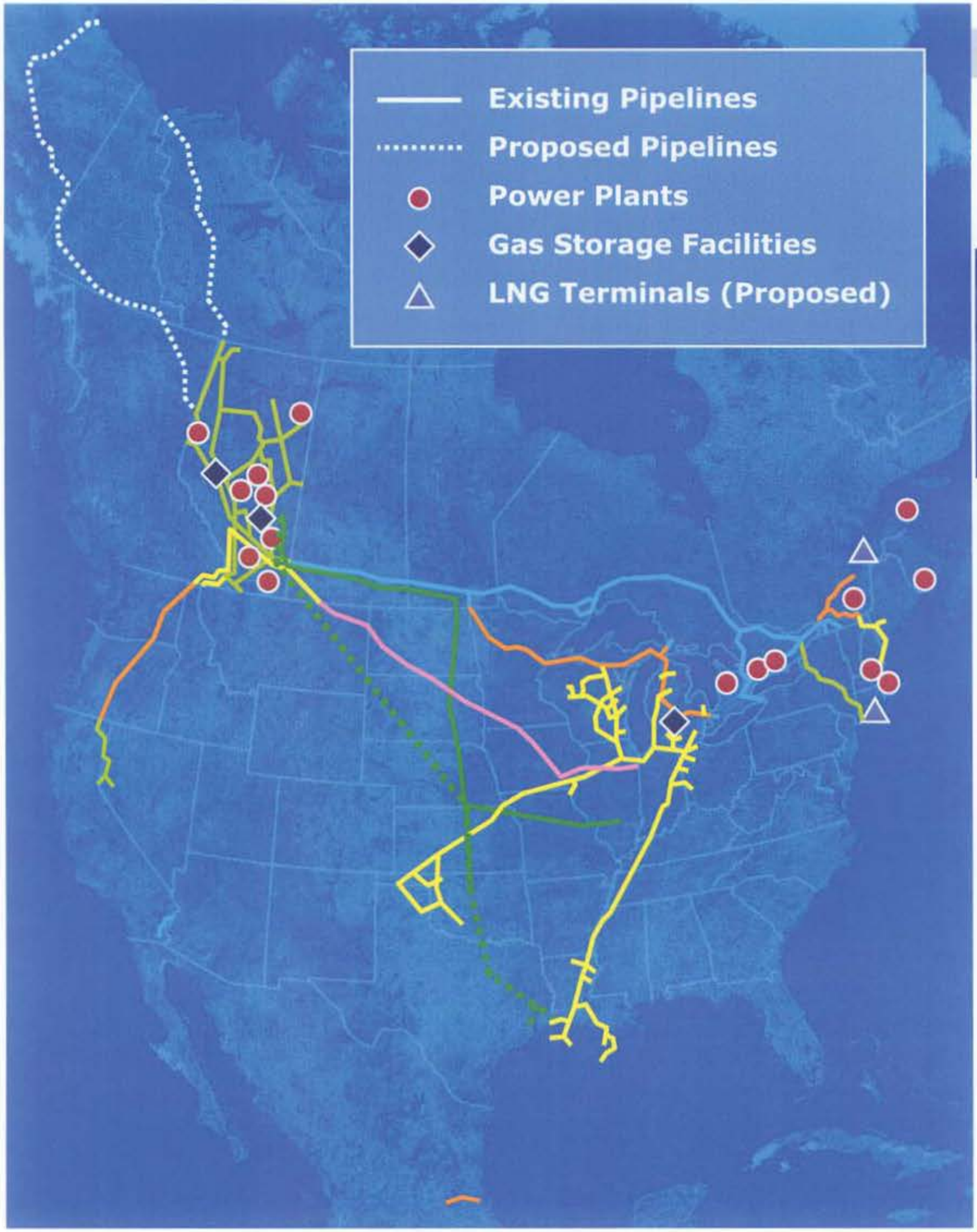
MPS (¢/kWh)

	Residential/ Small Commercial	Medium	Large (Distr. Voltage)	Large (Trans. Voltage)	Weighted Avg.
Distribution	4.77	1.96	2.25	1.14	3.15
Stranded Cost	2.40	2.45	2.51	2.53	2.45
Conservation & Solar Assess	0.15	0.15	0.15	0.005	0.11
Transmission	0.46	0.56	0.99	0.87	0.61
Total Delivery	7.78	5.11	5.90	4.54	6.32
Standard Offer	8.33	8.95	9.70	9.70	8.88
Total Rates	16.12	14.06	15.60	14.24	15.20

	Net Stranded Cost ($M)	Projected Net SC									
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019-2028
CMP	$47	$28	$33	$35	$33	$32	$20	$20			
BHE	$15	$15	$15	$15	$15	$15	$15	$15	$15	$15	$1.5
MPS	$12	$11	$11	$7	$2	$2	$2	$1			

Natural Gas "101" Transmission Pipeline

Portland Natural Gas Transmission System



TransCanada Corporation (TSX/NYSE: TRP)

Portfolio of Quality Assets

- **36,500 mi. of wholly owned pipeline**
- **Interests in an additional 4,800 mi. of pipeline**
- **15 Bcf/d throughput**
- **355 Bcf of natural gas storage capacity**
- **17 power plants**
- **10,200 megawatts**
- **Crude oil pipeline project**
- **Two proposed LNG terminals**

Forward-Looking Information

This presentation may contain certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "may", "should", "estimate", "project", "outlook", "forecast" or other similar words are used to identify such forward looking information. All forward-looking statements are based on TransCanada Pipeline ("TCPL") and Portland Natural Gas Transmission System ("PNGTS") beliefs and assumptions based on information available at the time such statements were made. The results or events predicted in this information may differ from actual results or events. Factors which could cause actual results or events to differ materially from current expectations include, among other things, the ability of TCPL and PNGTS to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the availability and price of energy commodities, regulatory decisions, changes in environmental and other laws and regulations, competitive factors in the pipeline and energy industry sectors, construction and completion of capital projects, access to capital markets, interest and currency exchange rates, technological developments and the current economic conditions in North America. By its nature, such forward looking information is subject to various risks and uncertainties which could cause TCPL's and PNGTS's actual results and experience to differ materially from the anticipated results or other expectations expressed. For additional information on these and other factors, see the reports filed by TCPL with Canadian securities regulators and with the U.S. Securities and Exchange Commission. Readers are cautioned not to place undue reliance on this forward looking information, which is given as of the date it is expressed in this presentation or otherwise, and TCPL and PNGTS undertake no obligation to update publicly or revise any forward looking information, whether as a result of new information, future events or otherwise, except as required by law.

Outline

- Natural Gas Basics
  - Composition
  - Heating Value
  - Transmission
  - Delivery to Local Distribution Systems
- Transmission Pipelines Serving Maine
  - Portland Natural Gas Transmission System
  - Maritimes and Northeast
- Supply and Demand for Natural Gas
  - North America
  - Shale Gas
  - Price vs. Oil, Propane

Composition of Natural Gas

HYDROCARBONS

	Chemical Formula	Normal Range of Composition %	Plant Products
Methane	CH_4	50-95	Sales Gas
Ethane	C_2H_6	3-12	.. Chemical Feedstock ..
Propane	C_3H_8	1-8	
Iso-Butane	C_4H_{10}	0-3	L.P.G
Normal Butane	C_4H_{10}	0-3	
Iso-Pentane	C_5H_{12}	0-2	
Normal Pentane	C_5H_{12}	0-2	Pentanes Plus, Condensate, Natural Gasoline
Hexane	C_6H_{14}	0-4	
Heptanes and Heavier	$C_7H_{16}+$	0-10	

Producer Gas

Plant

NON-HYDROCARBONS

Nitrogen	N_2	0-5	Inert
Carbon Dioxide	CO_2	0-10	Waste
Hydrogen Sulphide	H_2S	0-35	Elemental Sulphur

Natural Gas Heating Value

- When hydrocarbons are combusted in the presence of oxygen they produce carbon dioxide (CO_2), water vapor (H_2O), and heat. The heat produced is called the heating value of natural gas.
- Methane (C1) has a heating value of 1,010 BTU/ft^3
- The heating value of natural gas is between 1,030-1,100 BTU/ft^3
- Heavy hydrocarbons, like Ethane (C2), Propane (C3) and higher, increase the heating value of natural gas
- Components with no heating value like CO_2 and N_2 reduce the heating value of natural gas. They are sometimes intentionally added to “hot” gas to moderate the heating value.

Transmission of Natural Gas

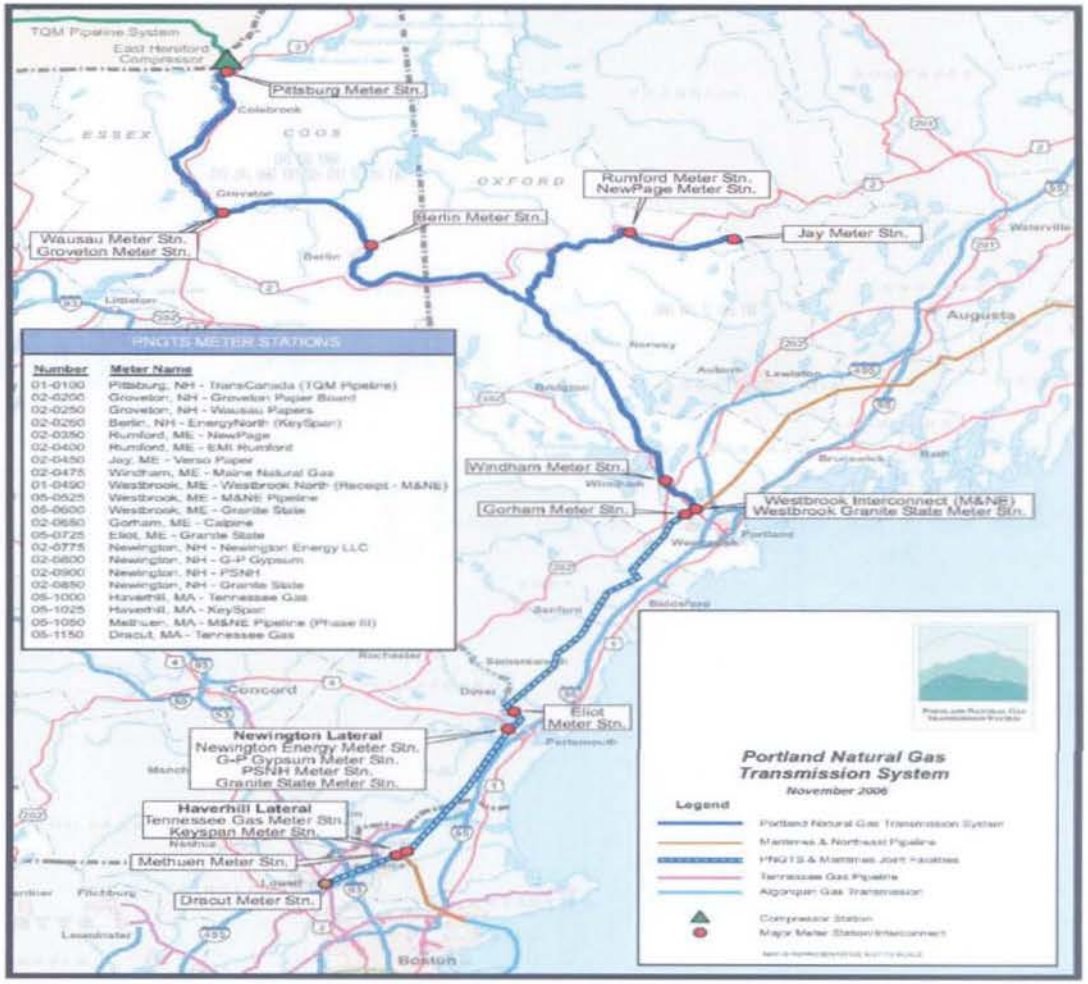
- Due to pressure drop on the pipeline, natural gas must be re-compressed; this is done at compressor stations.
- Compressor stations are typically spaced 50-80 miles apart.
- Gas ("fuel") from the flow stream is used to run the compressors (or they can be electric).
- Long distance transmission pipelines may be up to 48" in diameter, or in single and looped lines of 30" and 24" pipe.

Delivery of Natural Gas to Local Distribution Networks

- Interstate pipeline networks deliver gas to distribution companies at high pressure (700-1,440 psi).
- Before distribution within populated areas, gas pressure must be reduced to lower levels (~60 psi).
- Natural gas drops in pressure as it flows through local distribution networks. When the gas reaches the pressure regulator at customers' homes it is typically at 40-45 psi.
- The regulator further reduces the pressure to 0.25 psi for use in household appliances.
- Natural gas has no smell and must be odorized with sulfur compounds (mercaptan – "rotten egg" smell) for safety purposes before distribution.

Natural Gas Transmission Pipelines Serving Maine

Portland Natural Gas Transmission System



Maritimes & Northeast - US

MARITIMES & NORTHEAST PIPELINE, L.L.C.
FERC Gas Tariff
First Revised Volume No. 1

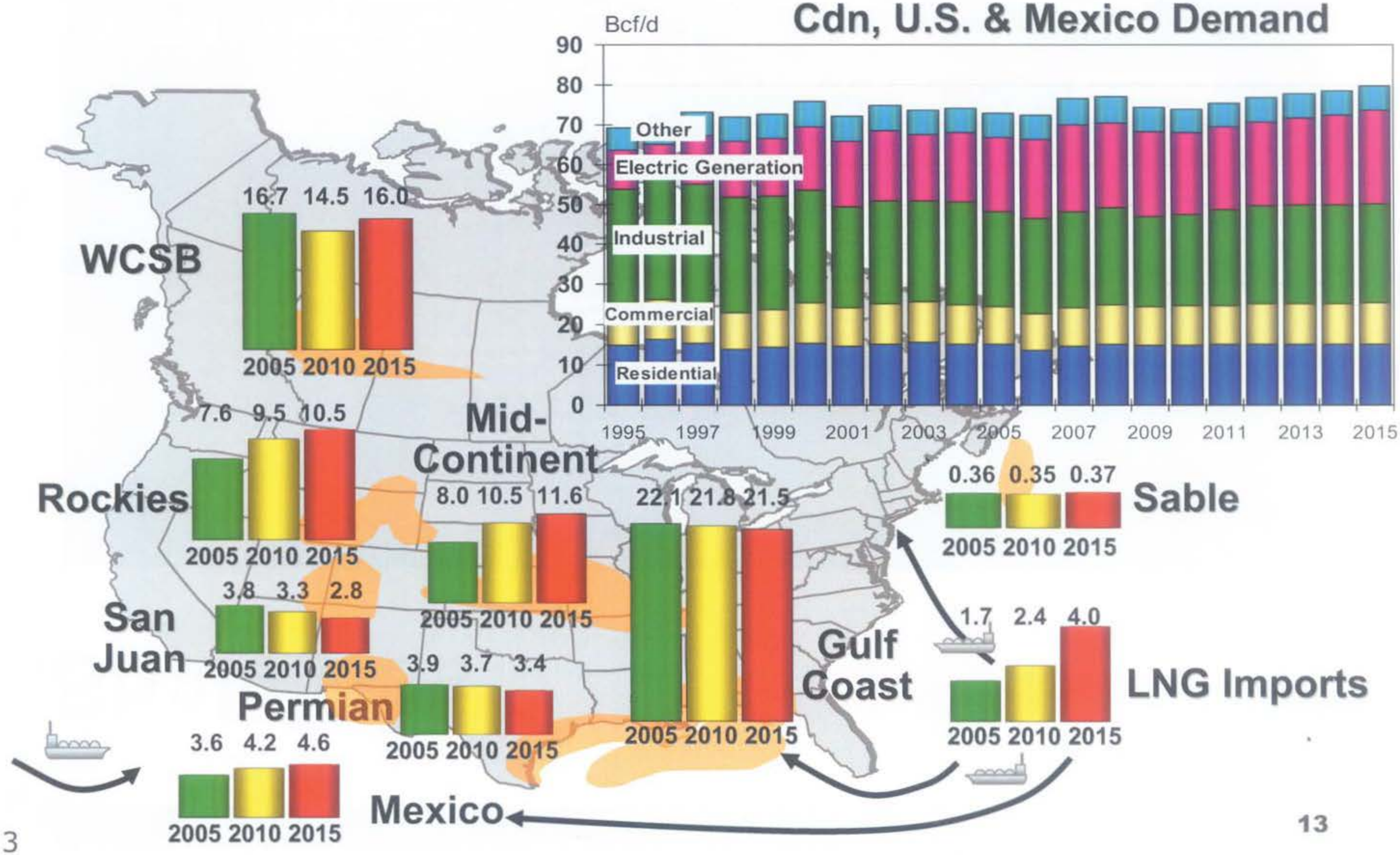
Third Revised Sheet No. 5
Superseding
Second Revised Sheet No. 5

Issued by: J. F. McHugh, Director, Rates & Regulatory Affairs
Issued on: April 30, 2008

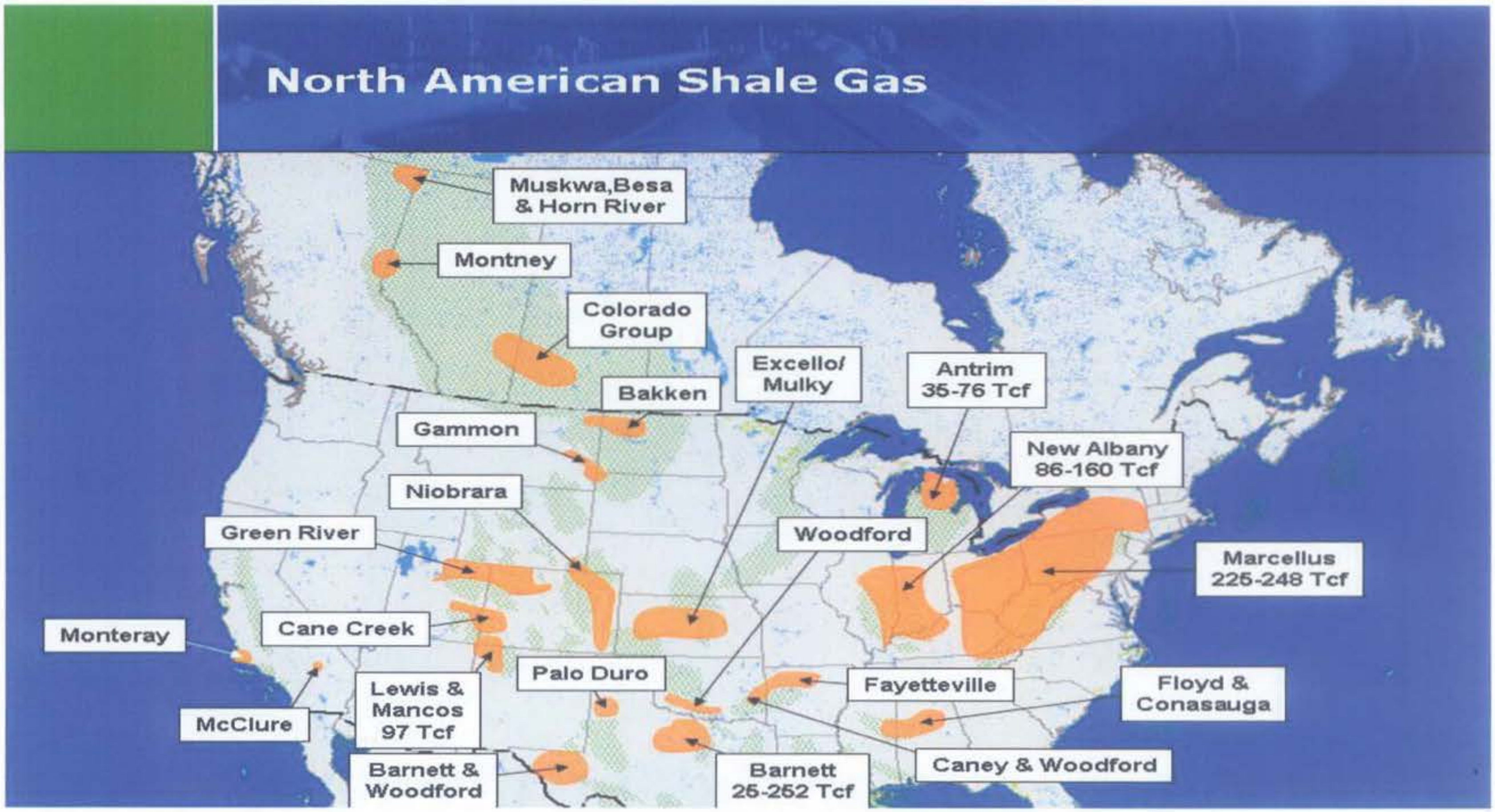
Effective on: June 1, 2008

Natural Gas Supply and Demand

North American Supply/Demand (Bcf/d)

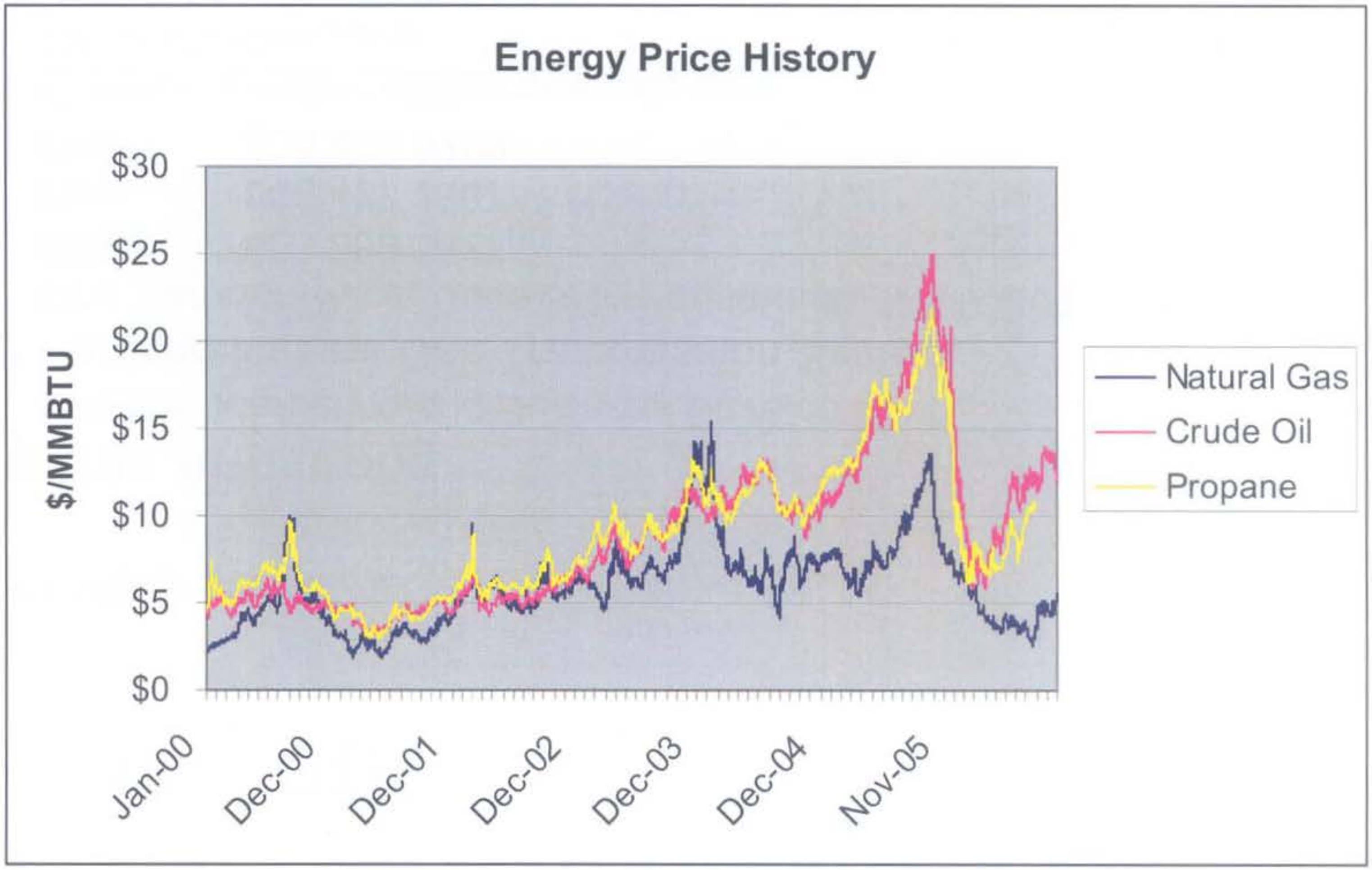


Shale Gas



North American Shale Gas
Muskwa,Besa & Horn River
Montney
Colorado Group
Bakken
Excello/ Mulky
Antrim 35-76 Tcf
Gammon
New Albany 86-160 Tcf
Niobrara
Green River
Woodford
Marcellus 225-248 Tcf
Monteray
Cane Creek
Palo Duro
Fayetteville
Floyd & Conasauga
McClure
Lewis & Mancos 97 Tcf
Barnett & Woodford
Barnett 25-252 Tcf
Caney & Woodford

Natural Gas Price vs. Oil, Propane



Thank you!

- For further questions:

- Cynthia Armstrong
  - Director, Marketing and Business Development
  - Portland Natural Gas Transmission System
  - One Harbour Place, Suite 375, Portsmouth, NH 03801
  - Office: 603 559 5527
  - Fax: 603 427 2807
  - Cell: 603 498 0782
  - Cynthia_armstrong@transcanada.com
  - IM: cynthiarmstrong
  - www.pngts.com

Canaport™ LNG Update
Winter 2010
REPSOL
KNUTSEN O.A.S.

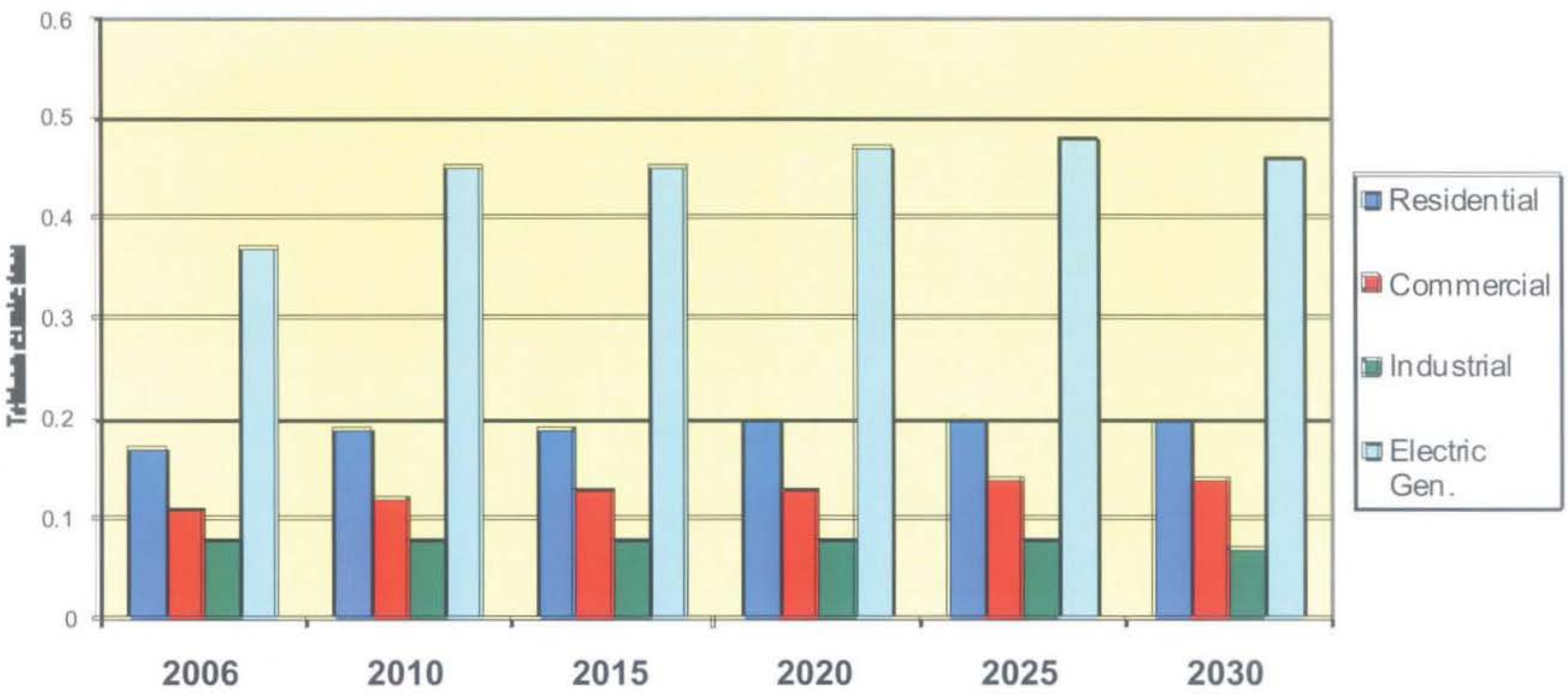
Repsol Overview

- **World-wide energy conglomerate headquartered in Madrid, Spain that has been in the energy industry for over 80 years**
- **Over 35,000 employees in more than 20 countries, with investments in more than 30 countries**
- **Total assets of ~$58 billion**
- **LNG investments:**
  - Canaport™ LNG regasification – 75% facility ownership and 100% (1 Bcfd) regas capacity ownership
  - Trinidad liquefaction – ownership interest in 3 trains ranging from 20% to 25% and ~450 MMcfd LNG purchase rights
  - Peru liquefaction (in service mid-2010) – 20% facility ownership and 100% (~500 MMcfd) LNG purchase rights
  - Leading LNG operator in the Atlantic basin via 50/50 JV with Gas Natural (Stream) - commercialized 231 cargoes in 2007; have 12 LNG tankers under long-term charter and 6 new tankers on order

Projected New England Gas Demand Growth

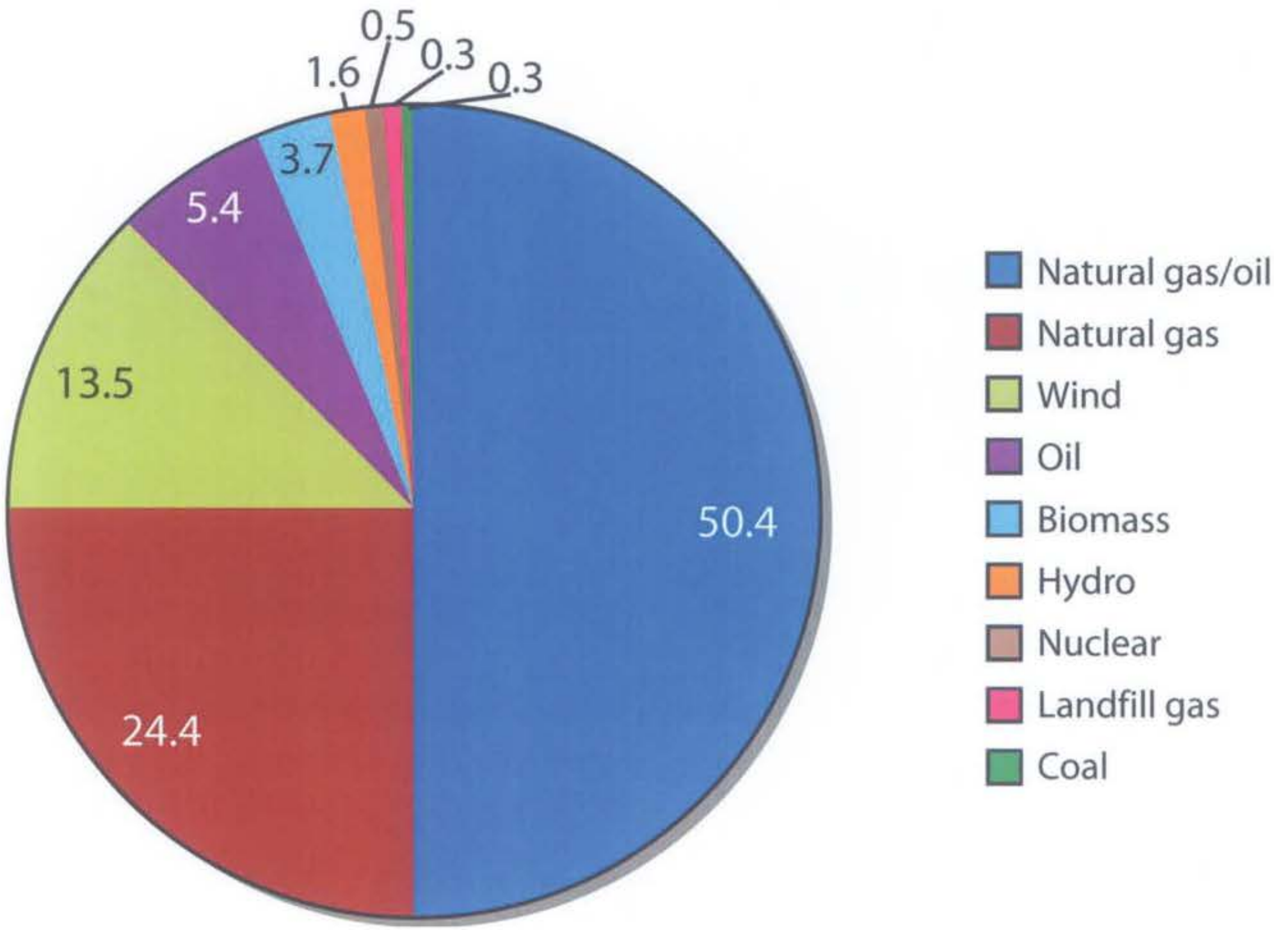
Over the next 25 years, the 2nd greatest rate of regional growth in the U.S. Natural gas demand is projected to grow by 22% from 2006 to 2025, from approx. 740 Bcf to 900 Bcf annually

Second Largest Growth in US



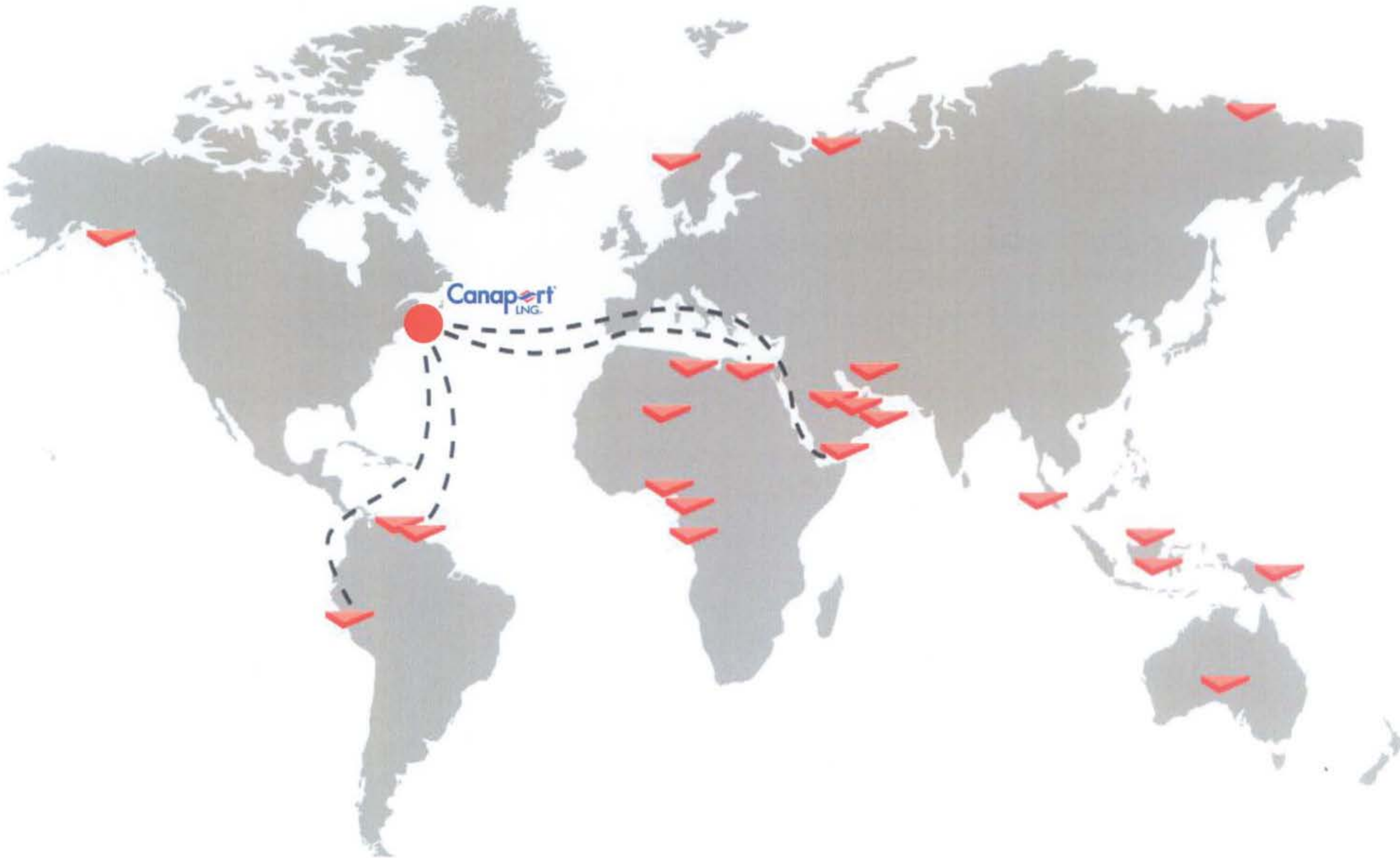
Source: U.S. Energy Information Administration, "2008 Annual Energy Outlook"

Power Generation by Fuel Type

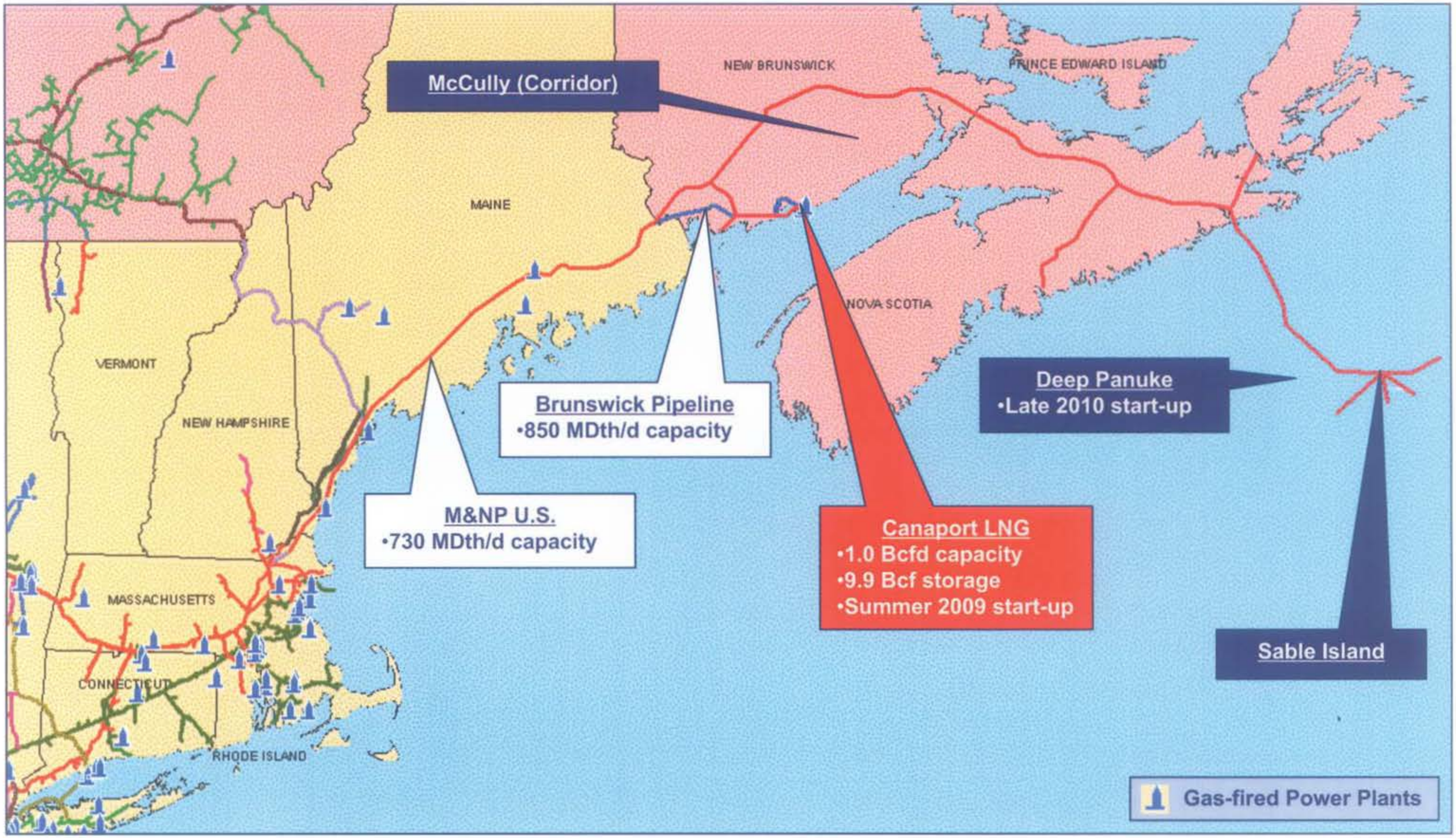


Source: ISO New England

Canaport LNG Global Sources



Gas Supply Diversification

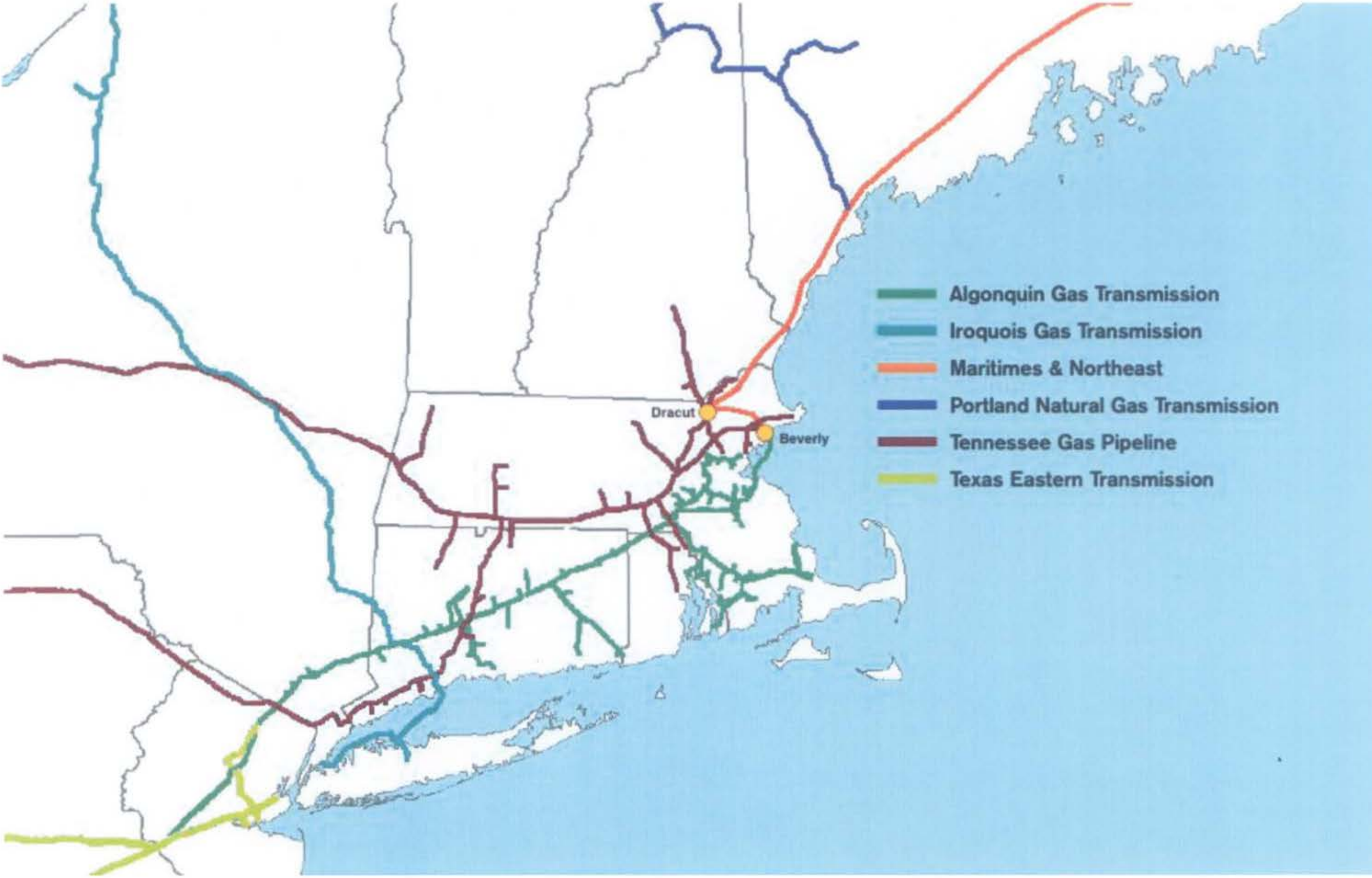


Canaport LNG Benefits

- Provides new source of safe, clean, and efficient gas supply to growing Northeast U.S. energy market
- Back-feeds the capacity constrained Northeast U.S. pipeline grid and minimizes new facility additions
- Attracts LNG suppliers to the high value gas markets in Northeast U.S. and Maritimes Canada
- Supplements declining Western and Maritimes Canada gas production
- Provides reliable back-up supply source when disruptions or restrictions occur due to weather events or other unscheduled outages
- Adds LNG storage that is readily accessible to the Northeast U.S. and Maritimes Canada markets

Q-FLEX MV Mesaimeer Arrives at Canaport LNG

A Safe, Clean, Reliable Source of Natural Gas



APPENDIX B: CATALOG OF CHP TECHNOLOGIES, US EPA COMBINED HEAT & POWER PARTNERSHIP, DEC. 2008

See http://www.epa.gov/chp/index.html for the entire report.

Catalog of CHP Technologies

U.S. Environmental Protection Agency
Combined Heat and Power Partnership

December 2008

Introduction to CHP Technologies

Introduction

Interest in combined heat and power (CHP) technologies has grown among energy customers, regulators, legislators, and developers over the past decade as consumers and providers seek to reduce energy costs while improving service and reliability. CHP is a specific form of distributed generation (DG), which refers to the strategic placement of electric power generating units at or near customer facilities to supply onsite energy needs. CHP enhances the advantages of DG by the simultaneous production of useful thermal and power output, thereby increasing the overall efficiency.

CHP offers energy and environmental benefits over electric-only and thermal-only systems in both central and distributed power generation applications. CHP systems have the potential for a wide range of applications and the higher efficiencies result in lower emissions than separate heat and power generation. The advantages of CHP broadly include the following:

- The simultaneous production of useful thermal and electrical energy in CHP systems lead to increased fuel efficiency.
- CHP units can be strategically located at the point of energy use. Such onsite generation avoids the transmission and distribution losses associated with electricity purchased via the grid from central stations.
- CHP is versatile and can be coupled with existing and planned technologies for many different applications in the industrial, commercial, and residential sectors.

EPA offers this catalog of CHP technologies as an online educational resource for regulatory, policy, permitting, and other interested CHP stakeholders. EPA recognizes that some energy projects will not be suitable for CHP; however, EPA hopes that this catalog will assist readers in identifying opportunities for CHP in applications where thermal-only or electric-only generation are currently being considered.

The remainder of this introductory summary is divided into sections. The first section provides a brief overview of how CHP systems work and the key concepts of efficiency and power-to-heat ratios. The second section summarizes the cost and performance characteristics of five CHP technologies in use and under development.

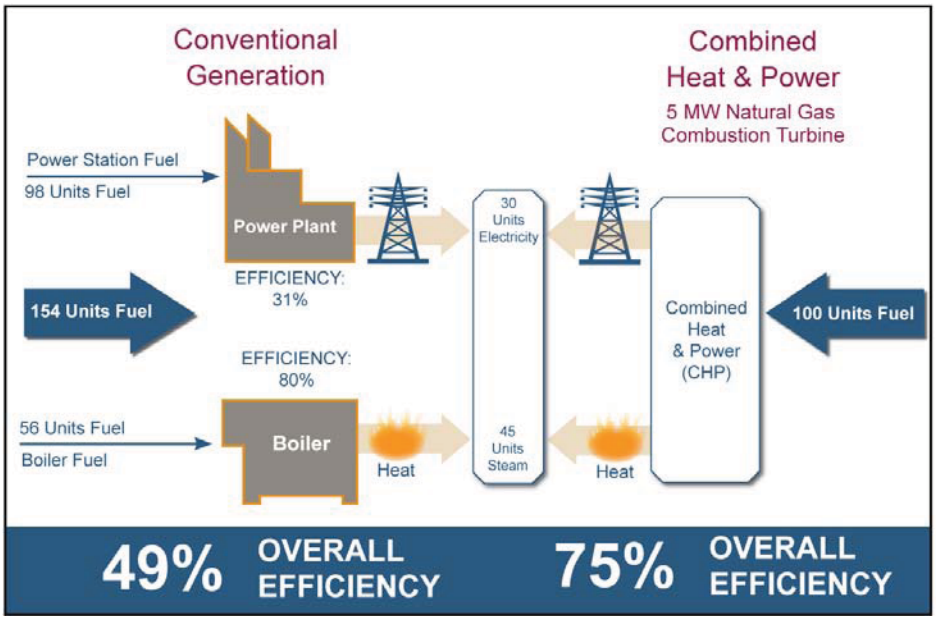
Overview of Combined Heat and Power

What is Combined Heat and Power?

CHP is the sequential or simultaneous generation of multiple forms of useful energy (usually mechanical and thermal) in a single, integrated system. CHP systems consist of a number of individual components—prime mover (heat engine), generator, heat recovery, and electrical interconnection—configured into an integrated whole. The type of equipment that drives the overall system (i.e., the prime mover) typically identifies the CHP system. Prime movers for CHP systems include reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells. These prime movers are capable of burning a variety of fuels, including natural gas, coal, oil, and alternative fuels to produce shaft power or mechanical energy. Although mechanical energy from the prime mover is most often used to drive a generator to produce electricity, it can also be used to drive rotating equipment such as compressors, pumps, and fans. Thermal energy from the system can be used in direct process applications or indirectly to produce steam, hot water, hot air for drying, or chilled water for process cooling.

Figure 1 shows the efficiency advantage of CHP compared with conventional central station power generation and onsite boilers. When considering both thermal and electrical processes together, CHP typically requires only ¾ the primary energy separate heat and power systems require. CHP systems utilize less fuel than separate heat and power generation, resulting for same level of output, resulting in fewer emissions.

Figure 1: CHP versus Separate Heat and Power (SHP) Production



Note: Assumes national averages for grid electricity and incorporates electricity transmission losses.

Expressing CHP Efficiency

Many of the benefits of CHP stem from the relatively high efficiency of CHP systems compared to other systems. Because CHP systems simultaneously produce electricity and useful thermal energy, CHP efficiency is measured and expressed in a number of different ways.[1] Table I summarizes the key elements of efficiency as applied to CHP systems.

[1] Measures of efficiency are denoted either as lower heating value (LHV) or higher heating value (HHV). HHV includes the heat of condensation of the water vapor in the products. Unless otherwise noted, all efficiency measures in this section are reported on an HHV basis.

Table I: Measuring the Efficiency of CHP Systems			
System	**Component**	**Efficiency Measure**	**Description**
Separate heat and power (SHP)	Thermal Efficiency (Boiler)	$\mathrm{EFF_Q} = \dfrac{\text{Net Useful Thermal Output}}{\text{Energy Input}}$	Net useful thermal output for the fuel consumed.
	Electric-only generation	$\mathrm{EFF_P} = \dfrac{\text{Power Output}}{\text{Energy Input}}$	Electricity Purchased From Central Stations via Transmission Grid.
	Overall Efficiency of separate heat and power (SHP)	$\mathrm{EFF_{SHP}} = \dfrac{P+Q}{P/\mathrm{EFF_{Power}} + Q/\mathrm{EFF_{Thermal}}}$	Sum of net power (P) and useful thermal energy output (Q) divided by the sum of fuel consumed to produce each.
Combined heat and power (CHP)	Total CHP System Efficiency	$\mathrm{EFF_{Total}} = (P+Q)/F$	Sum of the net power and net useful thermal output divided by the total fuel (F) consumed.
	FERC Efficiency Standard	$\mathrm{EFF_{FERC}} = \dfrac{(P+Q/2)}{F}$	Developed for the Public Utilities Regulatory Act of 1978, the FERC methodology attempts to recognize the quality of electrical output relative to thermal output.
	Effective Electrical Efficiency (or Fuel Utilization Efficiency, FUE):	$\mathrm{FUE} = \dfrac{P}{F - Q/\mathrm{EFF_{Thermal}}}$	Ratio of net power output to net fuel consumption, where net fuel consumption excludes the portion of fuel used for producing useful heat output. Fuel used to produce useful heat is calculated assuming typical boiler efficiency, usually 80 percent.
	Percent Fuel Savings	$S = 1 - \dfrac{F}{P/\mathrm{EFF_P} + Q/\mathrm{EFF_Q}}$	Fuel savings compares the fuel used by the CHP system to a separate heat and power system. Positive values represent fuel savings while negative values indicate that the CHP system is using more fuel than SHP.

Key:
P = Net power output from CHP system
Q = Net useful thermal energy from CHP system
F = Total fuel input to CHP system
$\mathrm{EFF_P}$ = Efficiency of displaced electric generation
$\mathrm{EFF_Q}$ = Efficiency of displaced thermal generation

As illustrated in Table I the efficiency of electricity generation in power-only systems is determined by the relationship between net electrical output and the amount of fuel used for the power generation. **Heat rate**, the term often used to express efficiency in such power generation systems, is represented in terms of Btus of fuel consumed per kWh of electricity generated. However, CHP plants produce useable heat as well as electricity. In CHP systems, the **total CHP efficiency** seeks to capture the energy content of both electricity and usable steam and is the net electrical output plus the net useful thermal output of the CHP system divided by the fuel consumed in the production of electricity and steam. While total CHP efficiency provides a measure for capturing the energy content of electricity and steam produced it does not adequately reflect the fact that electricity and steam have different qualities. The quality and value of electrical output is higher relative to heat output and is evidenced by the fact that electricity can be transmitted over long distances and can be converted to other forms of energy. To account for these differences in quality, the Public Utilities Regulatory Policies Act of 1978 (PURPA) discounts half of the thermal energy in its calculation of the efficiency standard (Eff_{FERC}). The EFF_{FERC} is represented as the ratio of net electric output plus half of the net thermal output to the total fuel used in the CHP system. Opinions vary as to whether the standard was arbitrarily set, but the FERC methodology does recognize the value of different forms of energy. The following equation calculates the FERC efficiency value for CHP applications.

$$EFF_{FERC} = \frac{P + Q/2}{F}$$

Where: P = Net power output from CHP system
F = Total fuel input to CHP system
Q = Net thermal energy from CHP system

Another definition of CHP efficiency is **effective electrical efficiency**, also known as **fuel utilization effectiveness (FUE)**. This measure expresses CHP efficiency as the ratio of net electrical output to net fuel consumption, where net fuel consumption excludes the portion of fuel that goes to producing useful heat output. The fuel used to produce useful heat is calculated assuming typical boiler efficiency, generally 80 percent. The effective electrical efficiency measure for CHP captures the value of both the electrical and thermal outputs of CHP plants. The following equation calculates FEU.

$$FUE = \frac{P}{F - Q/EFF_Q}$$

Where: Eff_Q = Efficiency of displaced thermal generation

FUE captures the value of both the electrical and thermal outputs of CHP plants and it specifically measures the efficiency of generating power through the incremental fuel consumption of the CHP system.

EPA considers fuel savings as the appropriate term to use when discussing CHP benefits relative to separate heat and power (SHP) operations. Fuel savings compares the fuel used by the CHP system to a separate heat and power system (i.e. boiler and electric-only generation). The following equation determines percent fuel savings (S).

$$S = 1 - \left[\frac{F}{P/_{Eff_P} + Q/_{Eff_Q}} \right]$$

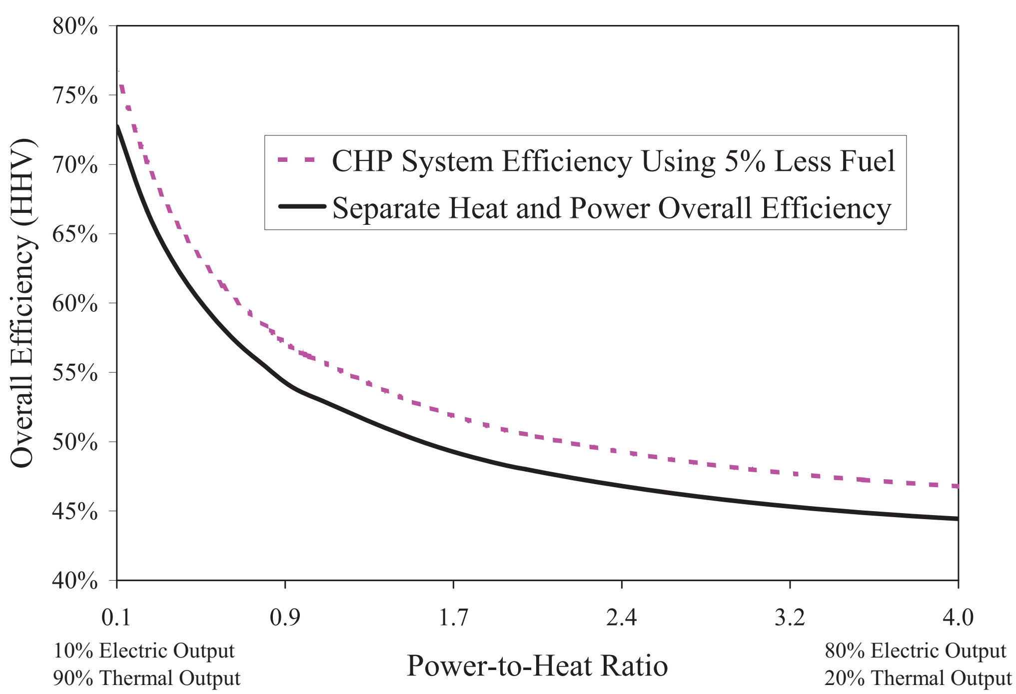
Where:
Eff_P = Efficiency of displaced electric generation
Eff_Q = Efficiency of displaced thermal-only facility

In the fuel saving equation given above, the numerator in the bracket term denotes the fuel used in the production of electricity and steam in a CHP system. The denominator describes the sum of the fuel used in the production of electricity (P/Eff_P) and thermal energy (Q/Eff_Q) in separate heat-and-power operations. Positive values represent fuel savings while negative values indicate that the CHP system in question is using more fuel than separate heat and power generation.

Another important concept related to CHP efficiency is the **power-to-heat ratio**. The power-to-heat ratio indicates the proportion of power (electrical or mechanical energy) to heat energy (steam or hot water) produced in the CHP system. Because the efficiencies of power generation and steam generation are likely to be considerably different, the power-to-heat ratio has an important bearing on how the total CHP system efficiency might compare to that of a separate power-and-heat system. Figure 2 illustrates this point. The illustrative curves display how the overall efficiency might change under alternate power-to-heat ratios for a separate power-and-heat system and a CHP system (for illustrative purposes, the CHP system is assumed to use 5 percent less fuel than its separate heat-and-power counterpart for the same level of electrical and thermal output).

Figure 2: Equivalent Separate Heat and Power Efficiency

Assumes 40 percent efficient electric and 80 percent efficient thermal generation



Overview of CHP Technologies

This catalog is comprised of five chapters that characterize each of the different CHP technologies (gas turbine, reciprocating engines, steam turbines, microturbines, and fuel cells) in detail. The chapters supply information on the applications of the technology, detailed descriptions of its functionality and design characteristics, performance characteristics, emissions, and emissions control options. The following sections provide snapshots of the five technologies, and a comparison of key cost and performance characteristics across the range of technologies that highlights the distinctiveness of each. Tables II and III provide a summary of the key cost and performance characteristics of the CHP technologies discussed in the catalog.

Table II: Summary of CHP Technologies

CHP system	Advantages	Disadvantages	Available sizes
Gas turbine	High reliability. Low emissions. High grade heat available. No cooling required.	Require high pressure gas or in-house gas compressor. Poor efficiency at low loading. Output falls as ambient temperature rises.	500 kW to 250 MW
Microturbine	Small number of moving parts. Compact size and light weight. Low emissions. No cooling required.	High costs. Relatively low mechanical efficiency. Limited to lower temperature cogeneration applications.	30 kW to 250 kW
Spark ignition (SI) reciprocating engine	High power efficiency with part-load operational flexibility. Fast start-up. Relatively low investment cost. Can be used in island mode and have good load following capability. Can be overhauled on site with normal operators. Operate on low-pressure gas.	High maintenance costs. Limited to lower temperature cogeneration applications. Relatively high air emissions. Must be cooled even if recovered heat is not used. High levels of low frequency noise.	< 5 MW in DG applications
Compression ignition (CI) reciprocating engine (dual fuel pilot ignition)			High speed (1,200 RPM) ≤4MW Low speed (102-514 RPM) 4-75 MW
Steam turbine	High overall efficiency. Any type of fuel may be used. Ability to meet more than one site heat grade requirement. Long working life and high reliability. Power to heat ratio can be varied.	Slow start up. Low power to heat ratio.	50 kW to 250 MW
Fuel Cells	Low emissions and low noise. High efficiency over load range. Modular design.	High costs. Low durability and power density. Fuels requiring processing unless pure hydrogen is used.	5 kW to 2 MW

Table III: Summary Table of Typical Cost and Performance Characteristics by CHP Technology*					
Technology	**Steam Turbine[1]**	**Recip. Engine**	**Gas Turbine**	**Microturbine**	**Fuel Cell**
Power efficiency (HHV)	15-38%	22-40%	22-36%	18-27%	30-63%
Overall efficiency (HHV)	80%	70-80%	70-75%	65-75%	55-80%
Effective electrical efficiency	75%	70-80%	50-70%	50-70%	55-80%
Typical capacity (MW_e)	0.5-250	0..01-5	0.5-250	0.03-0.25	0.005-2
Typical power to heat ratio	0.1-0.3	0.5-1	0.5-2	0.4-0.7	1-2
Part-load	ok	ok	poor	ok	good
CHP Installed costs ($\$/kW_e$)	430-1,100	1,100-2,200	970-1,300 (5-40 MW)	2,400-3,000	5,000-6,500
O&M costs ($\$/kWh_e$)	<0.005	0.009-0.022	0.004-0.011	0.012-0.025	0.032-0.038
Availability	near 100%	92-97%	90-98%	90-98%	>95%
Hours to overhauls	>50,000	25,000-50,000	25,000-50,000	20,000-40,000	32,000-64,000
Start-up time	1 hr - 1 day	10 sec	10 min - 1 hr	60 sec	3 hrs - 2 days
Fuel pressure (psig)	n/a	1-45	100-500 (compressor)	50-80 (compressor)	0.5-45
Fuels	all	natural gas, biogas, propane, landfill gas	natural gas, biogas, propane, oil	natural gas, biogas, propane, oil	hydrogen, natural gas, propane, methanol
Noise	high	high	moderate	moderate	low
Uses for thermal output	LP-HP steam	hot water, LP steam	heat, hot water, LP-HP steam	heat, hot water, LP steam	hot water, LP-HP steam
Power Density (kW/m^2)	>100	35-50	20-500	5-70	5-20
NO_x (lb/MMBtu) (not including SCR)	Gas 0.1-.2 Wood 0.2-.5 Coal 0.3-1.2	0.013 rich burn 3-way cat. 0.17 lean burn	0.036-0.05	0.015-0.036	0.0025-.0040
$lb/MWh_{TotalOutput}$ (not including SCR)	Gas 0.4-0.8 Wood 0.9-1.4 Coal 1.2-5.0.	0.06 rich burn 3-way cat. 0.8 lean burn	0.17-0.25	0.08-0.20	0.011-0.016

* Data are illustrative values for typically available systems; All costs are in 2007$

[1]For steam turbine, not entire boiler package

Technology

The first chapter of the catalog focuses on gas turbines as a CHP technology. Gas turbines are typically available in sizes ranging from 500 kW to 250 MW and can operate on a variety of fuels such as natural gas, synthetic gas, landfill gas, and fuel oils. Most gas turbines typically operate on gaseous fuel with liquid fuel as a back up. Gas turbines can be used in a variety of configurations including (1) simple cycle operation with a single gas turbine producing power only, (2) combined heat and power (CHP) operation with a single gas turbine coupled and a heat recovery exchanger and (3) combined cycle operation in which high pressure steam is generated from recovered exhaust heat and used to produce additional power using a steam turbine. Some combined cycle systems extract steam at an intermediate pressure for use and are combined cycle CHP systems. Many industrial and institutional facilities have successfully used gas turbines in CHP mode to generate power and thermal energy on-site. Gas turbines are well suited for CHP 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 (ºF). Much of the gas turbine-based CHP capacity currently existing in the United States consists of large combined-cycle CHP systems that maximize power production for sale to the grid. Simple-cycle CHP applications are common in smaller installations, typically less than 40 MW.

The second chapter of the catalog focuses on microturbines, which are small electricity generators that can burn a wide variety of fuels including natural gas, sour gases (high sulfur, low Btu content), and liquid fuels such as gasoline, kerosene, and diesel fuel/distillate heating oil. Microturbines use the fuel to create high-speed rotation that turns an electrical generator to produce electricity. In CHP operation, a heat exchanger referred to as the exhaust gas heat exchanger, transfers thermal energy from the microturbine exhaust to a hot water system. Exhaust heat can be used for a number of different applications including potable water heating, absorption chillers and desiccant dehumidification equipment, space heating, process heating, and other building uses. Microturbines entered field-testing in 1997 and the first units began commercial service in 2000. Available models range in sizes from 30 kW to 250 kW.

The third chapter in the catalog describes the various types of reciprocating engines used in CHP applications. Spark ignition (SI) and compression ignition (CI) are the most common types of reciprocating engines used in CHP-related projects. SI engines use spark plugs with a high-intensity spark of timed duration to ignite a compressed fuel-air mixture within the cylinder. SI engines are available in sizes up to 5 MW. Natural gas is the preferred fuel in electric generation and CHP applications of SI; however, propane, gasoline and landfill gas can also be used. Diesel engines, also called CI engines, are among the most efficient simple-cycle power generation options in the market. These engines operate on diesel fuel or heavy oil. Dual fuel engines, which are diesel compression ignition engines predominantly fueled by natural gas with a small amount of diesel pilot fuel, are also used. Reciprocating engines start quickly, follow load well, have good part-load efficiencies, and generally have high reliabilities. In many instances, multiple reciprocating engine units can be used to enhance plant capacity and availability. Reciprocating engines are well suited for applications that require hot water or low-pressure steam.

The fourth chapter of the catalog is dedicated to steam turbines that generate electricity from the heat (steam) produced in a boiler. The energy produced in the boiler is transferred to the turbine through high-pressure steam that in turn powers the turbine and generator. This separation of functions enables steam turbines to operate with a variety of fuels including natural gas, solid waste, coal, wood, wood waste, and agricultural by-products. The capacity of commercially available steam turbine typically ranges between 50 kW to over 250 MW. Although steam turbines are competitively priced compared to other prime movers, the costs of a complete boiler/steam turbine CHP system is relatively high on a per kW basis. This is because steam turbines are typically sized with low power to heat (P/H) ratios, and have high capital costs associated with the fuel and steam handling systems and the custom nature of most installations. Thus the ideal applications of steam turbine-based CHP systems include medium- and large-scale industrial or institutional facilities with high thermal loads and where solid or waste fuels are readily available for boiler use.

Chapter five in the catalog deals with an emerging technology that has the potential to serve power and thermal needs cleanly and efficiently. Fuel cells use an electrochemical or battery-like process to convert the chemical energy of hydrogen into water and electricity. In CHP applications, heat is generally recovered in the form of hot water or low-pressure steam (<30 psig) and the quality of heat is dependent on the type of fuel cell and its operating temperature. Fuel cells use hydrogen, which can be obtained from natural gas, coal gas, methanol, and other hydrocarbon fuels. There are currently five types of fuel cells under development. These include (1) phosphoric acid (PAFC), (2) proton exchange membrane (PEMFC), (3) molten carbonate (MCFC), (4) solid oxide (SOFC), and (5) alkaline (AFC). PAFC systems are commercially available in two sizes, 200 kW and 400 kW, and two MCFC systems are commercially available, 300 kW and 1200 kW. Due to the high installed cost of fuel cell systems, the most prominent DG applications of fuel cell systems are CHP-related.

Installed Cost[1]

The total plant cost or installed cost for most CHP technologies consists of the total equipment cost plus installation labor and materials, engineering, project management, and financial carrying costs during the construction period. The cost of the basic technology package plus the costs for added systems needed for the particular application comprise the total equipment cost.

Total installed costs for gas turbines, microturbines, reciprocating engines, and steam turbines are comparable. The total installed cost for typical gas turbines (5-40 MW) ranges from $970/kW to $1,300/kW, while total installed costs for typical microturbines in grid-interconnected CHP applications may range anywhere from $2,400/kW to $3,000/kW. Commercially available natural gas spark-ignited engine gensets have total installed costs of $1,100/kW to $2,200/kW, and steam turbines have total installed costs ranging from $350/kW to $700/kW. Fuel cells are currently the most expensive among the five CHP technologies with total installed costs ranging between $5,000/kW and $6,500/kW.

O&M Cost

Non-fuel operation and maintenance (O&M) costs typically include routine inspections, scheduled overhauls, preventive maintenance, and operating labor. O&M costs are comparable for gas turbines, gas engine gensets, steam turbines and fuel cells, and only a fraction higher for microturbines. Total O&M costs range from $0.004/kWh to $0.011/kWh for typical gas turbines, from $0.009/kWh to $0.022/kWh for commercially available gas engine gensets and are typically less than $0.005/kWh for steam turbines. Based on manufacturers offer service contracts for specialized maintenance, the O&M costs for microturbines are $0.015/kWh to $0.030/kWh. For fuel cells O&M costs range between $0.032/kWh and $0.038/kWh.

[1] All $ are 2007$.

Start-up Time

Start-up times for the five CHP technologies described in this catalog can vary significantly depending on the technology and fuel used. Gas turbines have relatively short start up time, though heat recovery considerations may constraint start up times. Microturbines require several minutes for start-up but require a power storage unit (typically a battery UPS) for start-up if the microturbine system is operating independently of the grid. Reciprocating engines have fast start-up capability, which allows for timely resumption of the system following a maintenance procedure. In peaking or emergency power applications, reciprocating engines can most quickly supply electricity on demand. Steam turbines, on the other hand, require long warm-up periods in order to obtain reliable service and prevent excessive thermal expansion, stress and wear. Fuel cells also have relatively long start-up times (especially for MCFC and SOFC). The longer start-up times for steam turbines and fuel cells make them more applicable to baseload needs.

Availability

Availability indicates the amount of time a unit can be used for electricity and/or steam production. Availability generally depends on the operational conditions of the unit. Frequent starts and stops of gas turbines can increase the likelihood of mechanical failure, though steady operation with clean fuels can permit gas turbines to operate for about a year without a shutdown. The estimated availability for gas turbines operating on clean gaseous fuels such as natural gas is over 95 percent.

Manufacturers of microturbines have targeted availabilities between 98 and 99 percent. Natural gas engine availabilities generally vary with engine type, speed, and fuel quality. Typically demonstrated availabilities for natural gas engine gensets in CHP applications is approximately 95 percent. Steam turbines have high availability rates—usually greater than 99 percent with longer than one year between shutdowns for maintenance and inspections. However, for purposes of CHP application it should be noted that this high availability rate is only applicable to the steam turbine itself and not to the boiler or HRSG that is supplying the steam. Some demonstrated and commercially available fuel cells have achieved greater than 90 percent availability.

Thermal Output

The ability to produce useful thermal energy from exhaust gases is the primary advantage of CHP technologies. Gas turbines produce a high quality (high temperature) thermal output suitable for most CHP applications. High-pressure steam can be generated or the exhaust can be used directly for process heating and drying. Microturbines produce exhaust output at temperatures in the 400ºF to 600ºF range, suitable for supplying a variety of building thermal needs. Reciprocating engines can produce hot water and low-pressure steam. Steam turbines are capable of operating over a broad range of steam pressures. They are custom designed to deliver the thermal requirements of CHP applications through use of backpressure or extraction steam at the appropriately needed pressure and temperature. Waste heat from fuel cells can be used primarily for domestic hot water and space heating applications.

Efficiency

Total CHP efficiency is a composite measure of the CHP fuel conversion capability and is expressed as the ratio of net output to fuel consumed. As explained earlier, for any technology the total CHP efficiency will vary depending on size and power-to-heat ratio. Combustion turbines achieve higher efficiencies at greater size and with higher power-to-heat ratios. The total CHP efficiency for gas turbines between 1 MW and 40 MW, and with power-to-heat ratios between 0.5 and 1.0, range from 70 percent to 75 percent. Unlike gas turbines, microturbines typically achieve 65 percent to 75 percent total CHP efficiency for a range of power-to-heat ratios. Commercially available natural gas spark engines ranging between 100 kW to 5 MW are likely to have total CHP efficiency in the 75 percent to 80 percent range. The total CHP efficiency of such engines will decrease with unit-size, and also with higher power-to-heat ratios. Although performance of steam turbines may differ substantially based on the fuel used, they are likely to achieve near 80 percent total CHP efficiency across a range of sizes and power-to–heat ratios. Fuel cell technologies may achieve total CHP efficiency in the 65 percent to 75 percent range.

Emissions

In addition to cost savings, CHP technologies offer significantly lower emissions rates compared to separate heat and power systems. The primary pollutants from gas turbines are oxides of nitrogen (NO_x), carbon monoxide (CO), and volatile organic compounds (VOCs) (unburned, non-methane hydrocarbons). Other pollutants such as oxides of sulfur (SO_x) and particulate matter (PM) are primarily dependent on the fuel used. Similarly, emissions of carbon dioxide are also dependent on the fuel used. Many gas turbines burning gaseous fuels (mainly natural gas) feature lean premixed burners (also called dry low-NO_x burners) that produce NO_x emissions ranging between 0.17 to 0.25 lbs/MWh[2] with no post-combustion emissions control. Typically commercially available gas turbines have CO emissions rates ranging between 0.23 lbs/MWh and 0.28 lbs/MWh. Selective catalytic reduction (SCR) or catalytic combustion can further help to reduce NO_x emissions by 80 percent to 90 percent from the gas turbine exhaust and carbon-monoxide oxidation catalysts can help to reduce CO by approximately 90 percent. Many gas turbines sited in locales with stringent emission regulations use SCR after-treatment to achieve extremely low NO_x emissions.

Microturbines have the potential for low emissions. All microturbines operating on gaseous fuels feature lean premixed (dry low NO_x, or DLN) combustor technology. The primary pollutants from microturbines include NO_x, CO, and unburned hydrocarbons. They also produce a negligible amount of SO_2. Microturbines are designed to achieve low emissions at full load and emissions are often higher when operating at part load. Typical NO_x emissions for microturbine systems range between 4ppmy and 9 ppmv or 0.08 lbs/MWh and 0.20 lbs/MWh. Additional NO_x emissions removal from catalytic combustion is microturbines is unlikely to be pursued in the near term because of the dry low NO_x technology and the low turbine inlet temperature. CO emissions rates for microturbines typically range between 0.06 lbs/MWh and 0.54 lbs/MWh.

Exhaust emissions are the primary environmental concern with reciprocating engines. The primary pollutants from reciprocating engines are NO_x, CO, and VOCs. Other pollutants such as SO_x and PM are primarily dependent on the fuel used. The sulfur content of the fuel determines emissions of sulfur compounds, primarily SO_2. NO_x emissions from small “rich burn” reciprocating engines with integral 3-way catalyst exhaust treatment can be as low as 0.06

[2] The NOx emissions reported in this section in lb/MWh are based on the total electric and thermal energy provided by the CHP system in MWh.

lbs/MWh. Larger lean burn engines have values of around 0.8 lbs/MWh without any exhaust treatment; however, these engines can utilize SCR for NOx reduction.

Emissions from steam turbines depend on the fuel used in the boiler or other steam sources, boiler furnace combustion section design, operation, and exhaust cleanup systems. Boiler emissions include NO_x, SO_x, PM, and CO. The emissions rates in steam turbines depend largely on the type of fuel used in the boiler. Typical boiler emissions rates for NO_x range between 0.3 lbs/MMBtu and 1.24 lbs/MMBtu for coal, 0.2 lbs/MMBtu and 0.5 lbs/MMBtu for wood, and 0.1 lbs/MMBtu and 0.2 lbs/MMBtu for natural gas. Uncontrolled CO emissions rates range between 0.02 lbs/MMBtu and 0.7 lbs/MMBtu for coal, approximately 0.06 lbs/MMBtu for wood, and 0.08 lbs/MMBtu for natural gas. A variety of commercially available combustion and post-combustion NO_x reduction techniques exist with selective catalytic reductions achieving reductions as high as 90 percent.

SO_2 emissions from steam turbines depend largely on the sulfur content of the fuel used in the combustion process. SO_2 comprises about 95 percent of the emitted sulfur and the remaining 5 percent is emitted as sulfur tri-oxide (SO_3). Flue gas desulphurization (FGD) is the most commonly used post-combustion SO_2 removal technology and is applicable to a broad range of different uses. FGD can provide up to 95 percent SO_2 removal.

Fuel cell systems have inherently low emissions profiles because the primary power generation process does not involve combustion. The fuel processing subsystem is the only significant source of emissions as it converts fuel into hydrogen and a low energy hydrogen exhaust stream. The hydrogen exhaust stream is combusted in the fuel processor to provide heat, achieving emissions signatures of less than 0.019 lbs/MWh of CO, less than 0.016 lbs/MWh of NO_x and negligible SO_x without any after-treatment for emissions. Fuel cells are not expected to require any emissions control devices to meet current and projected regulations.

While not considered a pollutant in the ordinary sense of directly affecting health, CO_2 emissions do result from the use the fossil fuel-based CHP technologies. The amount of CO_2 emitted in any of the CHP technologies discussed above depends on the fuel carbon content and the system efficiency. The fuel carbon content of natural gas is 34 lbs carbon/MMBtu; oil is 48 lbs of carbon/MMBtu and ash-free coal is 66 lbs of carbon/MMBtu.

Fuel Savings Equations

Absolute Fuel Savings:

$$F_{CHP} = F_{SHP} * (1-S) \text{ and } E_{SHP} = E_{CHP} * (1\text{-}S)$$

$$\text{Fuel Savings} = F_{SHP} - F_{CHP} = \frac{F_{CHP}}{1-S} - F_{CHP}$$

Where F_{CHP} = CHP fuel use
F_{SHP} = SHP fuel use
S = % fuel savings compared to SHP
E_{CHP} = CHP efficiency
E_{SHP} = SHP efficiency

$$= F_{CHP}\left[\frac{1}{1-S} - 1\right] = F_{CHP}\left[\frac{1}{1-S} - \frac{1-S}{1-S}\right] = F_{CHP}\left[\frac{1-1+S}{1-S}\right]$$

$$\text{Fuel Savings} = F_{CHP}\left[\frac{S}{1-S}\right] = F_{SHP} - F_{SHP} * (1-S) = F_{SHP} * S$$

Percentage Fuel Savings:

Equivalent separate heat and power (SHP) efficiency

$$Eff_{SHP} = \frac{\text{SHP Output}}{\text{SHP Fuel Input}} = \frac{P+Q}{P/Eff_P + Q/Eff_Q}$$

Where P = power output
Q = useful thermal output
Eff_P = power generation efficiency
Eff_Q = thermal generation efficiency

divide numerator and denominator by (P+Q)

$$Eff_{SHP} = \frac{1}{\frac{\%P}{Eff_P} + \frac{\%Q}{Eff_Q}}$$

Where percent P = P/(P+Q)
Percent Q =

CHP efficiency

$$Eff_{CHP} = \frac{P+Q}{F_{CHP}} = \frac{Eff_{SHP}}{(1-S)}$$

Substitute in equation for EFF_{SHP} and isolate S

$$\frac{P+Q}{F} = \frac{\frac{P+Q}{P/EFF_P + Q/EFF_Q}}{(1-S)}$$

$$(1-S)*\frac{P+Q}{F}=\frac{P+Q}{P/EFF_P+Q/EFF_Q}$$

Divide out (P+Q) and multiply by F

$$1-S=\frac{F}{\left(\frac{P}{Eff_P}+\frac{Q}{Eff_Q}\right)}$$

Percent fuel savings calculated from power and thermal output, CHP fuel input, and efficiency of displaced separate heat and power.

$$\boxed{S=1-\frac{F}{\frac{P}{Eff_P}+\frac{Q}{Eff_Q}}}$$

<u>Calculation of percentage power or percent thermal output from power to heat ratio:</u>

$$\text{Power to Heat Ratio}=X=P/Q=\%P/\%Q$$

$$P+Q=1$$

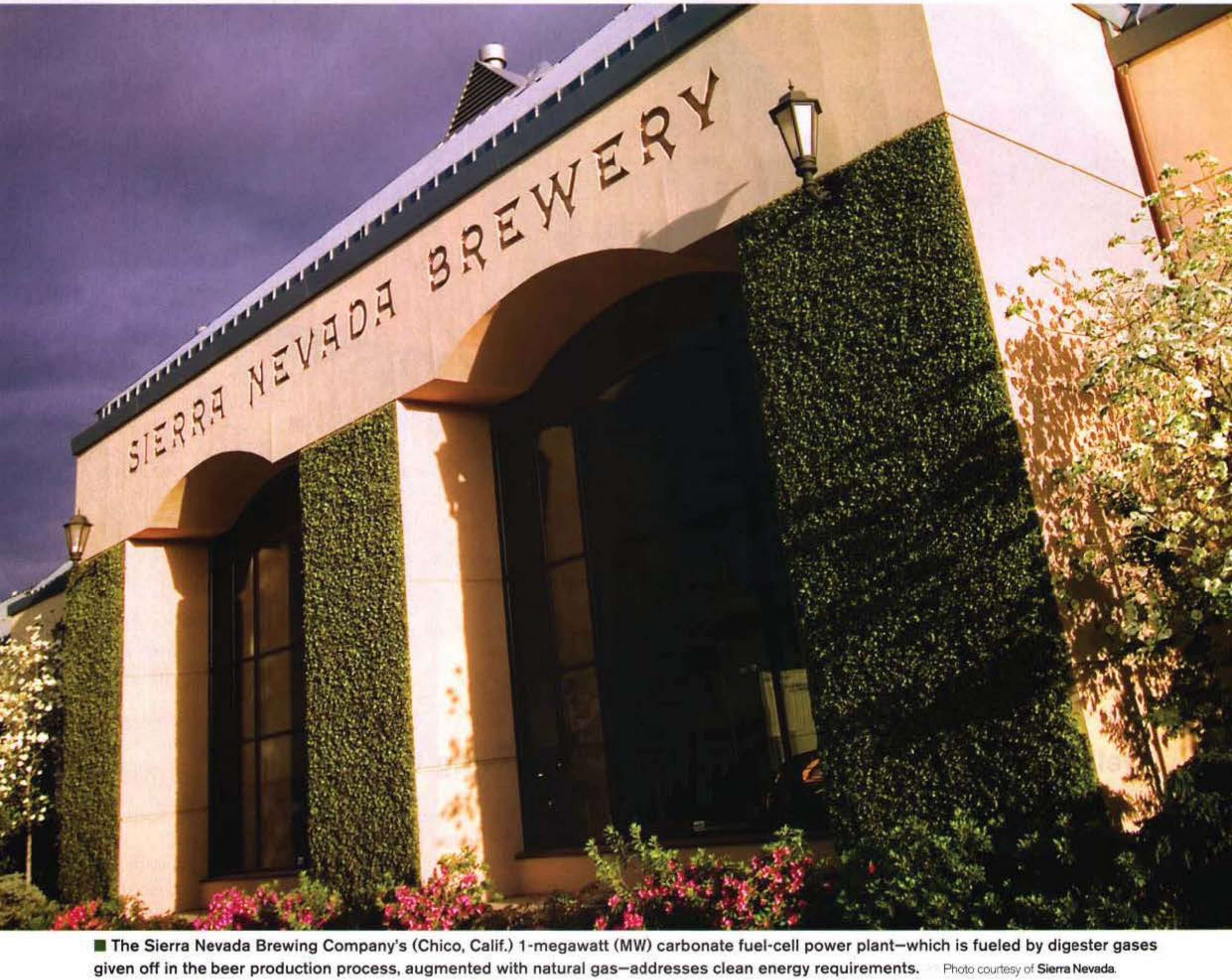
$P=X*Q$	$Q=\frac{P}{X}$
$P=X*(1-P)$	$Q=\frac{1-Q}{X}$
$P=X-X*P$	
$P+X*P=X$	$Q*X=1-Q$
$P*(1+X)=X$	$Q*(X+1)=1$
$P=\frac{X}{1+X}$	$Q=\frac{1}{X+1}$

APPENDIX C: SIERRA NEVADA BREWERY FUEL CELL EXAMPLE

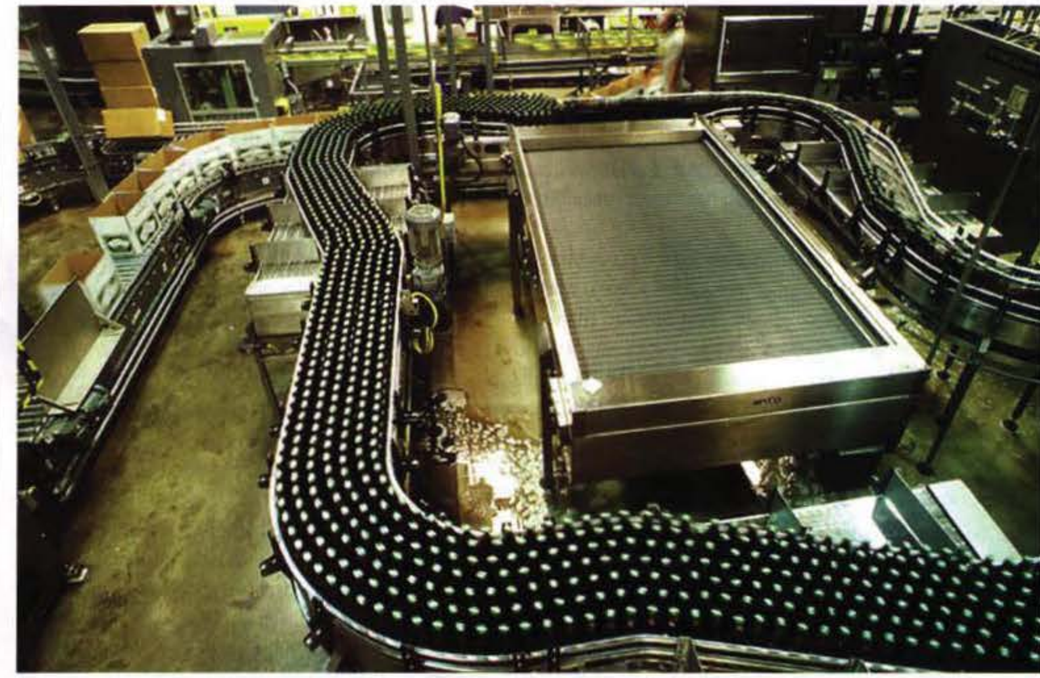
Pristine Power, Premium Beer

State-of-the-art brewing company meets its distributed generation needs using Ultra-Clean fuel cells and beer process byproducts.

By **Andy Skok**



■ The Sierra Nevada Brewing Company's (Chico, Calif.) 1-megawatt (MW) carbonate fuel-cell power plant—which is fueled by digester gases given off in the beer production process, augmented with natural gas—addresses clean energy requirements. Photo courtesy of **Sierra Nevada**.



Sierra Nevada's world-renowned beers are produced with high-quality electricity and high-value heat from the brewery's own fuel-cell power plants. >> Photo courtesy of Sierra Nevada.

Brewing high-quality beer requires a high-quality, reliable source of power. A brewing company that regards earth-friendly production processes with the same degree of importance as the brewing of its premium beers wants to produce that power cleanly and efficiently. How can a brewer use all its natural resources wisely and realize new efficiencies in the process? With an onsite stationary fuel-cell power plant that provides reliable power, fuel flexibility, and produces the highest possible electricity from the available biogas.

The Sierra Nevada Brewing Company in Chico, Calif., has installed a 1-megawatt (MW) carbonate fuel-cell power plant to address its clean energy requirements. The system is fueled by digester gases given off in the beer production process, augmented with natural gas. The power plant provides virtually 100 percent of Sierra Nevada's baseload electrical requirements, using a non-combustion hydrogen reforming process that produces almost no pollutant emissions and dramatically reduced greenhouse gases compared with traditional fossil-fuel power plants. The result is high-quality, utility-grade electric power, usable heat from cogeneration, and ultra-clean emissions. In addition, overall energy efficiency for the new power system is twice that of power supplied from the electrical grid.

The new fuel cell is part of a large commitment to environmental responsibility by Sierra Nevada, which has incorporated heat recovery, byproduct recycling, and computerized energy reduction equipment into its state-of-the art beer-making processes. But Sierra quickly discovered that its fuel cells, more than just another addition to its environmental efforts, became the "heart" of an energy-cycle system of clean power, cogeneration and wastewater recycling.

In addition to reducing overall fuel requirements and carbon dioxide emissions, the system eliminates air pollutants equivalent to removing 500 gasoline-powered cars from California roadways each year.

THE FUEL CELL POWER PLANT

There are many types of fuel cells, from experimental mobile systems in Detroit's show cars to the ultra high-tech system found on the Space Shuttle. But one type—large stationary carbonate fuel cells like the one at Sierra Nevada—already has a history of proven results in distributed generation systems around the world. When Sierra Nevada founder Ken Grossman went looking for a fuel cell in 2004, products like the DFC300, a 250-kilowatt (kW) fuel-cell plant produced by FuelCell Energy, Inc., was an obvious choice. The fuel flexibility offered by the company's Direct FuelCell (DFC) power plants was an important part of the decision criteria.

Configured in size for such applications, the DFC300 is a high-temperature, high-efficiency carbonate fuel cell. The installation of four DFC300s offered Sierra Nevada the ability to provide virtually all of its baseload electrical power. DFC power plant operate on biofuels—gases from food processing, landfills, and wastewater treatment—in addition to natural gas, ethanol, diesel and coal gas. Sierra Nevada's four DFC300s use a combination of digester gas and natural gas to complete the hydrogen reforming process. Natural gas is provided through a standard distribution network. This ability to maximize electricity production from readily available onsite fuel resources is an important advantage. Other types of fuel cells require external fuel processing to obtain a supply of hydrogen.

The DFC power plant uses a modular design containing separately configured units for power generation (i.e., fuel cell modules), Electrical Balance of Plant (EBOP) including power conditioning and grid interconnect, and Mechanical Balance of Plant (MBOP) including fuel supply and conditioning, and heat recovery. Each module is arranged on its own skid to provide efficient transport to the installation site, installation flexibility, and ease of access for plant maintenance.

The MBOP incorporates a fuel and water treatment module and de-oxidizing reactors to treat the natural gas. The Heat Recovery Unit/Anode Gas Oxidizer (HRU/AGO) module then takes the treated fuel and cold water and produces a heated fuel/water mixture for delivery to the fuel-cell module, which consists of fuel cells arranged into stacks that produce DC power. The EBOP converts DC to AC for use in conjunction with the existing utility grid. This module contains the inverter, control system, operator interface, transformers and all grid interconnection hardware.

GREEN IS JUST THE START

This type of fuel cell initially gained popularity for its ultra-clean emissions signature, and recent installations have only served to heighten that advantage. The DFC300 is certified to meet the stringent distributed generation emissions standards established by the California Air Resources Board (CARB), which qualifies the fuel cell as an Ultra-Clean technology, and also exempts it from air-pollution control and air-quality district permitting requirements. The certification also qualifies the fuel cell for preferential rate treatment by the California Public Utilities Commission (CPUC), which includes the elimination of additional exit fees and standby charges. Combined with additional incentives from CPUC's Self-Generation Incentive Program (SGIP), the

Pristine Power, Premium Beer

fuel-cell system demonstrated its ability to save Sierra Nevada money, not only with its efficient operation, but also with fast-track installation and rate benefits.

For an environmentally-conscious brewer in a state devoted to green solutions, such advantages can be priceless, because beyond the regulations lie the actual clean-air benefits at and around the brewery site. Because the fuel cells make their energy through a non-combustion process, they produce virtually zero emissions of nitrogen oxides (NOx), sulfur oxides (SOx), and particulate matter.

Thus, in addition to reducing overall fuel requirements and carbon dioxide emissions, the system eliminates air pollutants equivalent to removing 500 gasoline-powered cars from California roadways each year. These advantages, and Sierra Nevada's commitment to generating clean power, were highlighted by Governor Arnold Schwarzenegger in his speech at the dedication of Sierra Nevada's fuel cell plant in July 2005: "Like any business, Sierra Nevada was

The installation of four DFC300 high temperature, high-efficiency carbonate fuel cells provide the brewery virtually all of its baseload electrical power. Photo courtesy of **Sierra Nevada**.

looking for stable, affordable, reliable power, and they wanted to limit the environmental impact of their operation," Schwarzenegger said. "They found the answer in a hydrogen fuel cell system that generates power onsite."

As Sierra Nevada joined the ranks of institutions noted for providing clean, distributed generation of electrical power, it began to realize that making the most of clean natural gas was only the beginning. The fuel cells quickly became the heart of a power cycle that maximizes their benefits, further reducing emissions and increasing the brewer's efficiency. The secret is twofold: Using the waste heat from the fuel cells to produce steam for the brewing process, and using a key byproduct of that process called Anaerobic Digester Gas (ADG) to fuel the DFC power plant. The DFC power plant converts the limited supply of ADG gas into the most electricity possible by a distributed generation technology, thereby maximizing the resource.

COLD BEER STARTS WITH HOT STEAM

Because of their high operating temperatures, carbonate fuel cells are an excellent source of heat energy, and that heat energy is typically recovered to boost the cell's overall energy production efficiency. At Sierra Nevada, the 650-degree waste-heat from the fuel cells are harvested as 125-PSI steam, used not only for heating and boiler needs throughout the facility, but also to help power the brewing process itself by boiling the beer. The brewery's world-renowned beers are produced with high-quality electricity and high-value heat from its own fuel-cell power plants.

This cogeneration of useful energy from the waste heat associated with the conversion process is a key differentiator for large stationary fuel cell applications. Sierra Nevada's 1 MW fuel cell installation provides over 1.5 million BTUs of waste heat each year, which, when put to good use, can significantly boost the plant's overall efficiency and save money.

CLEANER POWER FROM CLEANING HOUSE

Beer brewing produces a variety of byproducts, including large amounts of wastewater. As part of the water-treatment process, anaerobic digesters use natural biological processes to generate methane from this wastewater. The brewery site's filtration system then purifies this methane gas and feeds it to the fuel-cell power plants, further reducing the plant's need for pipeline fuel.

The DFC300 can operate with this natural fuel just as efficiently as with natural gas. Two of the plant's four DFC300s can now operate on ADG, natural gas, or any combination of the two fuels. Using this system, the fuel cells can provide up to 400 kW of electricity exclusively from ADG, reducing the brewery's fuel costs by up to 40 percent each year, and maximizing electricity production from the available biogas. Not only does this multi-fuel ability reduce reliance on the power grid, it further reduces the net levels of carbon released into the atmosphere, and saves money. And regardless of the fuel used, the fuel-cell plants are classified as an Ultra-Clean installation under California law.

A RESPONSIBLE NEIGHBOR

By producing power onsite at the facility, Sierra Nevada reduces the need for power from the local utility, allowing the grid to operate in a less congested, and therefore more efficient, manner. This benefit came into clear focus during the California heat wave of 2006, when the utility asked the brewery to reduce its energy use to the baseload amount supplied by the fuel cells to avoid leaving nearby Chico residents with no power to support critical air-conditioning needs in the 110-degree Fahrenheit heat—a potentially life threatening scenario. The brewery was able to maintain normal operations thanks to the fuel cells, and the citizens of Chico continued to have electricity without the need to resort to emergency diesel generators.

POWER, PROFITS AND PROFILE

The overall process, as described by Grossman, is a "hand in glove" cycle of benefits. Sierra uses high-efficiency fuel cells to maximize electricity production from available fuels, taps the cogenerated heat to brew its high-quality beers, then recycles once-wasted byproducts to create additional fuel, which the versatile DFC power plants use to maximize electricity production and begin the process again. For a company like Sierra Nevada, whose dedication to environmental stewardship plans include everything from water conservation to carbon dioxide recycling, this cycle pays benefits with every turn.

And there is a second cycle of benefits: money savings, plant efficiency and corporate image. The fuel cells produce electricity at high efficiency, and cogeneration reduces the need for fuel, increasing profit. The ADG produced reduces fuel demand, further increasing profit. And the environmentally-friendly corporate image of Sierra Nevada receives a big lift from beer drinkers, increasing potential sales—and boosting profit. Far from an added expense or regulatory hassle, multi-fuel Ultra-Clean fuel-cell power plants can provide energy savings, cost savings and a green, friendly corporate image—an image Sierra's customers can savor with each sip of their premium beer. SF

Andy Skok is a senior marketing executive for FuelCell Energy in Danbury, Conn., where he has more than 28 years of experience in various management positions. Skok received his undergraduate degree in materials engineering from Wilkes University and attended Yale University's Chemical Engineering Graduate School. He has published numerous technical articles, and actively participates on many national and international committees.

APPENDIX D: SMALL AND LARGE SYSTEM TRIGENERATION ENERGY MODELS

Self-Gen, Inc.
Scarborough, Maine

Town Hall - Tri-Generation
Basic Emmissions Data

CHP Results

The results generated by the CHP Emissions Calculator are intended for eductional and outreach purposes only; it is not designed for use in developing emission inventories or preparing air permit applications.

Annual Emissions Analysis	CHP System	Displaced Electricity Production	Displaced Thermal Production	Emissions/Fuel Reduction	Percent Reduction
NOx (tons/year)	0.19	0.55	0.24	0.60	76%
SO2 (tons/year)	0.00	1.08	0.00	1.07	100%
CO2 (tons/year)	733	1,041	282	590	45%
Carbon (metric tons/year)	181	257	70	146	45%
Fuel Consumption (MMBtu/year)	12,562	17,459	4,828	9,725	44%
Acres of Forest Equivalent				122	
Number of Cars Removed				97	

This CHP project will reduce emissions of Carbon Dioxide (CO_2) by 590 tons per year

This is equal to 146 metric tons of carbon equivalent (MTCE) per year

This reduction is equal to removing the carbon that would be absorbed by 122 acres of forest

OR

This reduction is equal to removing the carbon emissions of 97 cars

Self-Gen, Inc.
Scarborough, Maine

Town Hall - Tri-Generation
Basic Emmissions Data

CHP Results

CHP Technology:	Recip Engine - Rich Burn	
Fuel:	Natural Gas	
Unit Capacity:	150	kW
Number of Units:	1	
Total CHP Capacity:	150	kW
Operation:	8,760	hours per year
Heat Rate:	9,560	Btu/kWh HHV
CHP Fuel Consumption:	12,562	MMBtu/year
Duct Burner Fuel Consumption:	-	MMBtu/year
Total Fuel Consumption:	**12,562**	**MMBtu/year**
Total CHP Generation:	**1,314**	**MWh/year**
Useful CHP Thermal Output:	3,863	MMBtu/year for thermal applications (non-cooling)
	3,003	MMBtu/year for electric applications (cooling and electric heating)
	6,866	**MMBtu/year Total**
Displaced On-Site Production for		Existing Gas Boiler
Thermal (non-cooling) Applications:	0.10	lb/MMBtu NOx
	0.00%	sulfur content
Displaced Electric Service (cooling and electric heating):	30	tons of cooling capacity from CHP system
CHP:	Single-Effect Absorption Chiller	
Replaces:	0.94 kW/ton (COP=3.75) Best available, rotary screw compressor, air-cooled, <150 tons capacity	
	3.74	COP
Displaced Electricity Profile:	eGRID Average Fossil 2005	
Egrid State:	ME	
Distribution Losses:	8%	
Displaced Electricity Production:	1,314	MWh/year CHP generation
	165	MWh/year Displaced Electric Demand (cooling)
	-	MWh/year Displaced Electric Demand (electric heating)
	129	MWh/year Transmission Losses
	1,607	**MWh/year Total**

Town Hall - Tri-Generation
Basic Emmissions Data

CHP Results

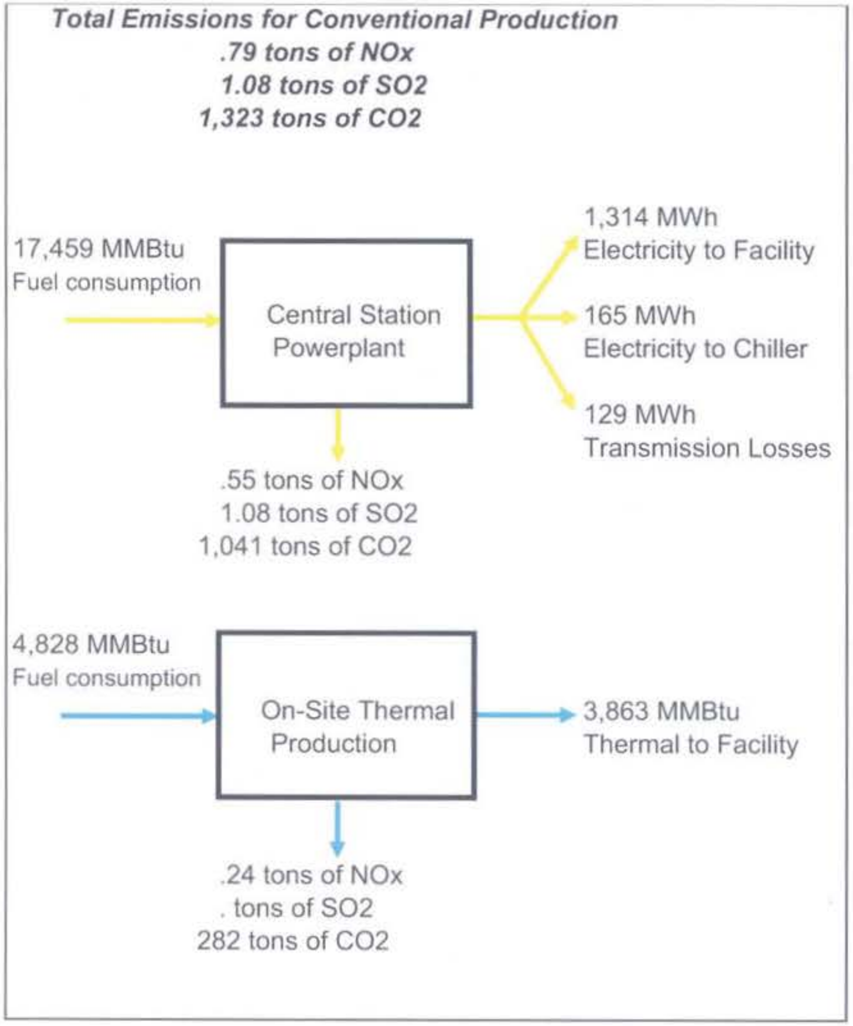
Annual Analysis for CHP				
	CHP System: Recip Engine - Rich Burn			Total Emissions from CHP System
NOx (tons/year)	0.19	-		0.19
SO2 (tons/year)	0.00	-		0.00
CO2 (tons/year)	733	-		733
Carbon (metric tons/year)	181	-		181
Fuel Consumption (MMBtu/year)	12,562	-		12,562

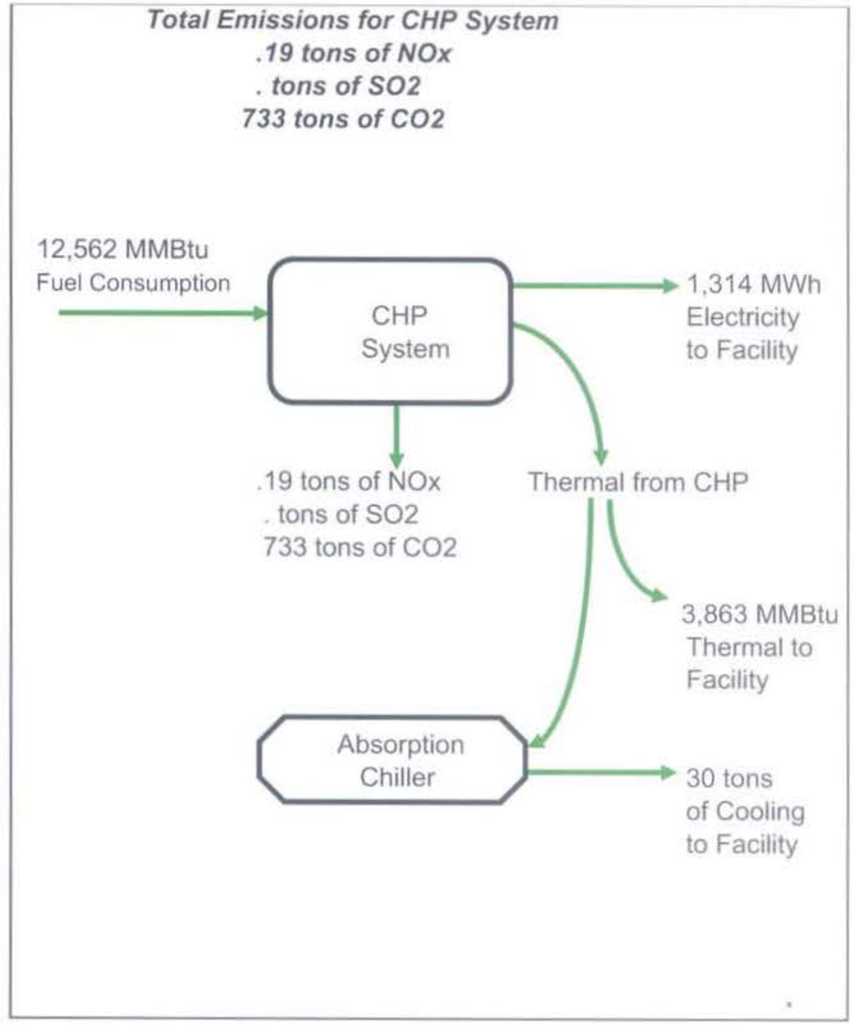
Annual Analysis for Displaced Production for Thermal (non-cooling) Applications				
				Total Displaced Emissions from Thermal Production
NOx (tons/year)				0.24
SO2 (tons/year)				0.00
CO2 (tons/year)				282
Carbon (metric tons/year)				70
Fuel Consumption (MMBtu/year)				4,828

Annual Analysis for Displaced Electricity Production					
	Displaced CHP Electricity Generation	Displaced Electricity for Cooling	Displaced Electricity for Heating	Transmission Losses	Total Displaced Emissions from Electricity Generation
NOx (tons/year)	0.45	0.06	-	0.04	0.55
SO2 (tons/year)	0.88	0.11	-	0.09	1.08
CO2 (tons/year)	851	106.67	-	83.28	1,041
Carbon (metric tons/year)	210	26	-	21	257
Fuel Consumption (MMBtu/year)	14,273	1,789	-	1,397	17,459

CHP Results

CHP
EPA COMBINED HEAT AND POWER PARTNERSHIP





CHP Results

Emission Rates	CHP System including Duct Burners	Recip Engine - Rich Burn Alone	Displaced Electricity
NOx (lb/MWh)	0.30	0.30	0.69
SO2 (lb/MWh)	0.01	0.01	1.34
CO2 (lb/MWh)	1,116	1,116	1,295

Emission Rates	Displaced Thermal Production
NOx (lb/MMBtu)	0.10
SO2 (lb/MMBtu)	0.00059
CO2 (lb/MMBtu)	117

Energy Category	Existing Energy "Debits"	Tri-Gen Energy "Debits"	Tri-gen Energy "Credits"	
Existing Building Usage - Thermal 1:	-$24,957.00	-$122,289.71		
Excess Energy Required/Saved - Thermal 2:		$0.00	$0.00	Excess Thermal 'sold'
Chiller Electrical Savings - Thermal 3:			$30,120.65	Electric Chiller Savings
Town Hall Total - Electric:	-$66,169.00	$0.00	$116,496.35	Excess Electricity Net Metered with Other Municipal Meters (10)
Totals – 2006 - 2007:	-$91,126.00	-$122,289.71	$146,617.00	
Maintenance Cost / Year plus Escrow:			-$10,442.29	
Energy Difference Adjustment "+" or "-":			-$31,163.71	
TOTAL SAVINGS PER YEAR:			$105,011.00	
Estimated Project Cost - "1" - 150 kW Engine:			$498,629.40	
	4.75	Year Payback	$49,863	10% Grant
w/ 10% grant	4.27	Year Payback	$448,766.46	
w/ $200/kW credit	4.62	Year Payback	$485,629.40	

Large-Tri-Gen-NG Model
Emissions Metrics

Combine Metrics with attached
Combined-Cycle S/T/G emissions data.

CHP Results

The results generated by the CHP Emissions Calculator are intended for eductional and outreach purposes only; it is not designed for use in developing emission inventories or preparing air permit applications.

Annual Emissions Analysis					
	CHP System	Displaced Electricity Production	Displaced Thermal Production	Emissions/Fuel Reduction	Percent Reduction
NOx (tons/year)	52.33	16.25	22.45	(13.63)	-35%
SO2 (tons/year)	0.19	31.73	23.55	55.10	100%
CO2 (tons/year)	36,644	30,700	24,085	18,142	33%
Carbon (metric tons/year)	9,060	7,591	5,955	4,486	33%
Fuel Consumption (MMBtu/year)	627,996	514,877	299,382	186,264	23%
Acres of Forest Equivalent				3,738	
Number of Cars Removed				2,996	

This CHP project will reduce emissions of Carbon Dioxide (CO2) by 18,142 tons per year

This is equal to 4,486 metric tons of carbon equivalent (MTCE) per year

This reduction is equal to removing the carbon that would be absorbed by 3,738 acres of forest

OR

This reduction is equal to removing the carbon emissions of 2,996 cars

Combine Metrics with attached Combined-Cycle S/T/G emissions data.

CHP Results

CHP Technology:	Combustion Turbine	
Fuel:	Natural Gas	
Unit Capacity:	4,600	kW
Number of Units:	1	
Total CHP Capacity:	4,600	kW
Operation:	8,760	hours per year
Heat Rate:	15,585	Btu/kWh HHV
CHP Fuel Consumption:	627,996	MMBtu/year
Duct Burner Fuel Consumption:	-	MMBtu/year
Total Fuel Consumption:	**627,996**	**MMBtu/year**
Total CHP Generation:	**40,296**	**MWh/year**
Useful CHP Thermal Output:	224,537	MMBtu/year for thermal applications (non-cooling)
	45,051	MMBtu/year for electric applications (cooling and electric heating)
	269,588	**MMBtu/year Total**
Displaced On-Site Production for Thermal (non-cooling) Applications:		Existing Distillate Oil Boiler
	0.15	lb/MMBtu NOx
	0.15%	sulfur content
Displaced Electric Service (cooling and electric heating):	1,500	tons of cooling capacity from CHP system
CHP:	Single-Effect Absorption Chiller	
Replaces:	1.26 kW/ton (COP=2.8) Average new unit, rotary screw compressor, air-cooled, <150 tons capacity	
	2.79	COP
Displaced Electricity Profile:	eGRID Average Fossil 2005	
Egrid State:	ME	
Distribution Losses:	8%	
Displaced Electricity Production:	40,296	MWh/year CHP generation
	3,311	MWh/year Displaced Electric Demand (cooling)
	-	MWh/year Displaced Electric Demand (electric heating)
	3,792	MWh/year Transmission Losses
	47,399	**MWh/year Total**

Combine Metrics with attached
Combined-Cycle S/T/G emissions data.

CHP Results

Annual Analysis for CHP

	CHP System: Combustion Turbine			Total Emissions from CHP System
NOx (tons/year)	52.33	-		52.33
SO2 (tons/year)	0.19	-		0.19
CO2 (tons/year)	36,644	-		36,644
Carbon (metric tons/year)	9,060	-		9,060
Fuel Consumption (MMBtu/year)	627,996	-		627,996

Annual Analysis for Displaced Production for Thermal (non-cooling) Applications

				Total Displaced Emissions from Thermal Production
NOx (tons/year)				22.45
SO2 (tons/year)				23.55
CO2 (tons/year)				24,085
Carbon (metric tons/year)				5,955
Fuel Consumption (MMBtu/year)				299,382

Annual Analysis for Displaced Electricity Production

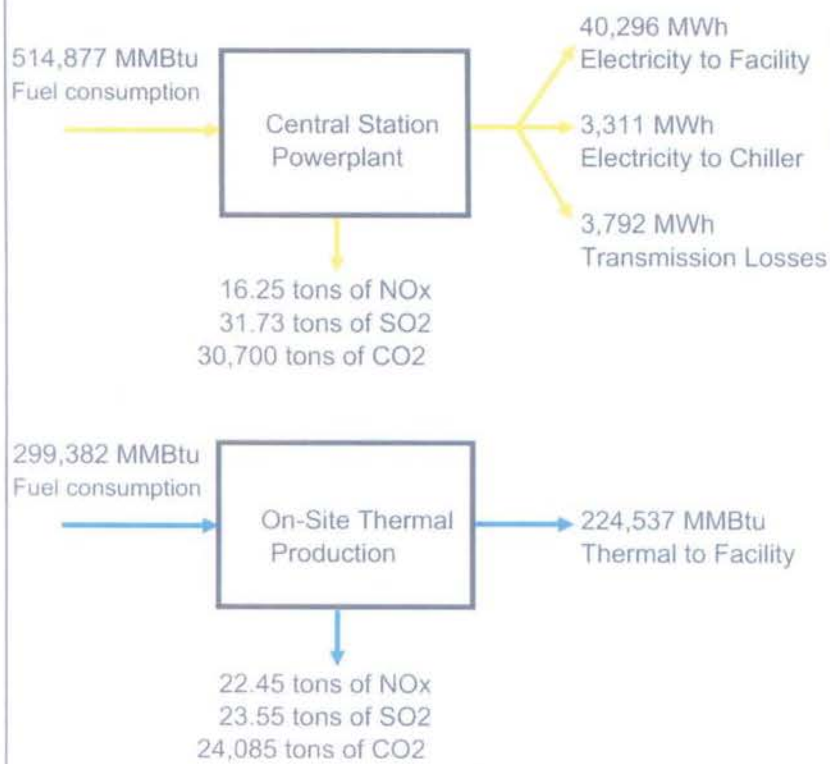
	Displaced CHP Electricity Generation	Displaced Electricity for Cooling	Displaced Electricity for Heating	Transmission Losses	Total Displaced Emissions from Electricity Generation
NOx (tons/year)	13.82	1.14	-	1.30	16.25
SO2 (tons/year)	26.98	2.22	-	2.54	31.73
CO2 (tons/year)	26,099	2,144.67	-	2,455.99	30,700
Carbon (metric tons/year)	6,453	530	-	607	7,591
Fuel Consumption (MMBtu/year)	437,718	35,969	-	41,190	514,877

Large-Tri-Gen-NG Model
Emissions Metrics

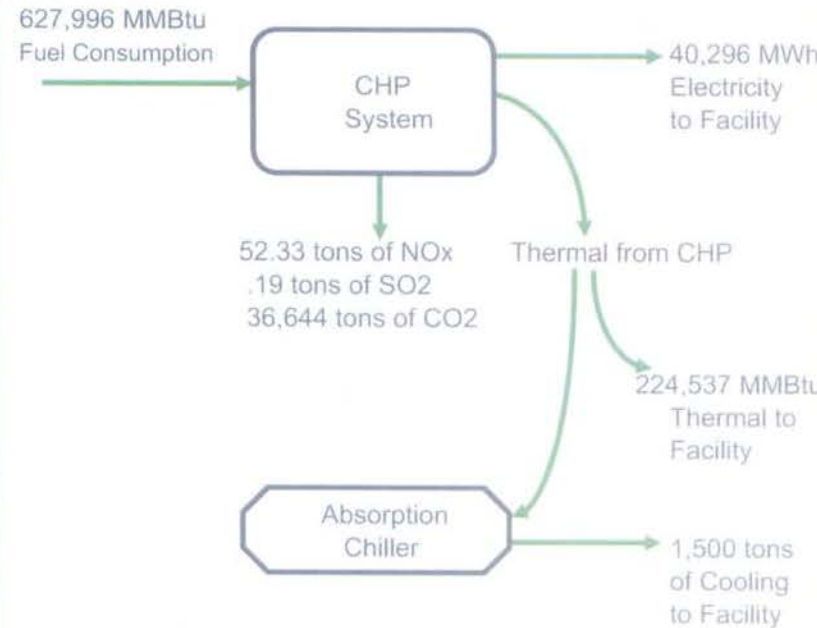
Combine Metrics with attached Combined-Cycle S/T/G emissions data.

CHP Results

Total Emissions for Conventional Production
38.71 tons of NOx
55.29 tons of SO2
54,785 tons of CO2



Total Emissions for CHP System
52.33 tons of NOx
.19 tons of SO2
36,644 tons of CO2



Combine Metrics with attached
Combined-Cycle S/T/G emissions data.

CHP Results

CHP
EPA COMBINED HEAT AND POWER PARTNERSHIP

Emission Rates	CHP System including Duct Burners	Combustion Turbine Alone	Displaced Electricity
NOx (lb/MWh)	2.60	2.60	0.69
SO2 (lb/MWh)	0.01	0.01	1.34
CO2 (lb/MWh)	1,819	1,819	1,295

Emission Rates	Displaced Thermal Production
NOx (lb/MMBtu)	0.15
SO2 (lb/MMBtu)	0.15735
CO2 (lb/MMBtu)	161

Large Tri-Gen - 600 kW Back-Pressure Steam-Turbine-Generator

Combined Cycle Model

Note: Energy Source is excess waste steam for combined-cycle model, not NG.

CHP Results

CHP
EPA COMBINED HEAT AND POWER PARTNERSHIP

The results generated by the CHP Emissions Calculator are intended for eductional and outreach purposes only; it is not designed for use in developing emission inventories or preparing air permit applications.

Annual Emissions Analysis	CHP System	Displaced Electricity Production	Displaced Thermal Production	Emissions/Fuel Reduction	Percent Reduction
NOx (tons/year)	6.81	1.31	9.64	4.13	38%
SO2 (tons/year)	0.04	2.55	10.11	12.62	100%
CO2 (tons/year)	7,946	2,467	10,336	4,857	38%
Carbon (metric tons/year)	1,965	610	2,556	1,201	38%
Fuel Consumption (MMBtu/year)	136,181	41,372	128,480	33,671	20%
Acres of Forest Equivalent				1,001	
Number of Cars Removed				802	

This CHP project will reduce emissions of Carbon Dioxide (CO2) by 4,857 tons per year

This is equal to 1,201 metric tons of carbon equivalent (MTCE) per year

This reduction is equal to removing the carbon that would be absorbed by 1,001 acres of forest

OR

This reduction is equal to removing the carbon emissions of 802 cars

Note: Energy Source is excess waste steam for combined-cycle model, not NG.

CHP Results

CHP Technology:	Backpressure Steam Turbine	
Fuel:	Natural Gas	
Unit Capacity:	600	kW
Number of Units:	1	
Total CHP Capacity:	600	kW
Operation:	5,840	hours per year
Heat Rate:	38,864	Btu/kWh HHV
CHP Fuel Consumption:	136,181	MMBtu/year
Duct Burner Fuel Consumption:	-	MMBtu/year
Total Fuel Consumption:	**136,181**	**MMBtu/year**
Total CHP Generation:	**3,504**	**MWh/year**
Useful CHP Thermal Output:	96,360	MMBtu/year for thermal applications (non-cooling)
	-	MMBtu/year for electric applications (cooling and electric heating)
	96,360	**MMBtu/year Total**
Displaced On-Site Production for Thermal (non-cooling) Applications:		Existing Distillate Oil Boiler
	0.15	lb/MMBtu NOx
	0.15%	sulfur content
Displaced Electric Service (cooling and electric heating):		
	There is no displaced cooling service	
Displaced Electricity Profile:	eGRID Average Fossil 2005	
Egrid State:	ME	
Distribution Losses:	8%	
Displaced Electricity Production:	3,504	MWh/year CHP generation
	-	MWh/year Displaced Electric Demand (cooling)
	-	MWh/year Displaced Electric Demand (electric heating)
	305	MWh/year Transmission Losses
	3,809	**MWh/year Total**

Large Tri-Gen - 600 kW Back-Pressure Steam-Turbine-Generator

Combined Cycle Model

Note: Energy Source is excess waste steam for combined-cycle model, not NG.

CHP Results

CHP
EPA COMBINED HEAT AND POWER PARTNERSHIP

Annual Analysis for CHP	CHP System: Backpressure Steam Turbine			Total Emissions from CHP System
NOx (tons/year)	6.81	-		6.81
SO2 (tons/year)	0.04	-		0.04
CO2 (tons/year)	7,946	-		7,946
Carbon (metric tons/year)	1,965	-		1,965
Fuel Consumption (MMBtu/year)	136,181	-		136,181

Annual Analysis for Displaced Production for Thermal (non-cooling) Applications				Total Displaced Emissions from Thermal Production
NOx (tons/year)				9.64
SO2 (tons/year)				10.11
CO2 (tons/year)				10,336
Carbon (metric tons/year)				2,556
Fuel Consumption (MMBtu/year)				128,480

Annual Analysis for Displaced Electricity Production	Displaced CHP Electricity Generation	Displaced Electricity for Cooling	Displaced Electricity for Heating	Transmission Losses	Total Displaced Emissions from Electricity Generation
NOx (tons/year)	1.20	-	-	0.10	1.31
SO2 (tons/year)	2.35	-	-	0.20	2.55
CO2 (tons/year)	2,269	-	-	197.35	2,467
Carbon (metric tons/year)	561	-	-	49	610
Fuel Consumption (MMBtu/year)	38,062	-	-	3,310	41,372

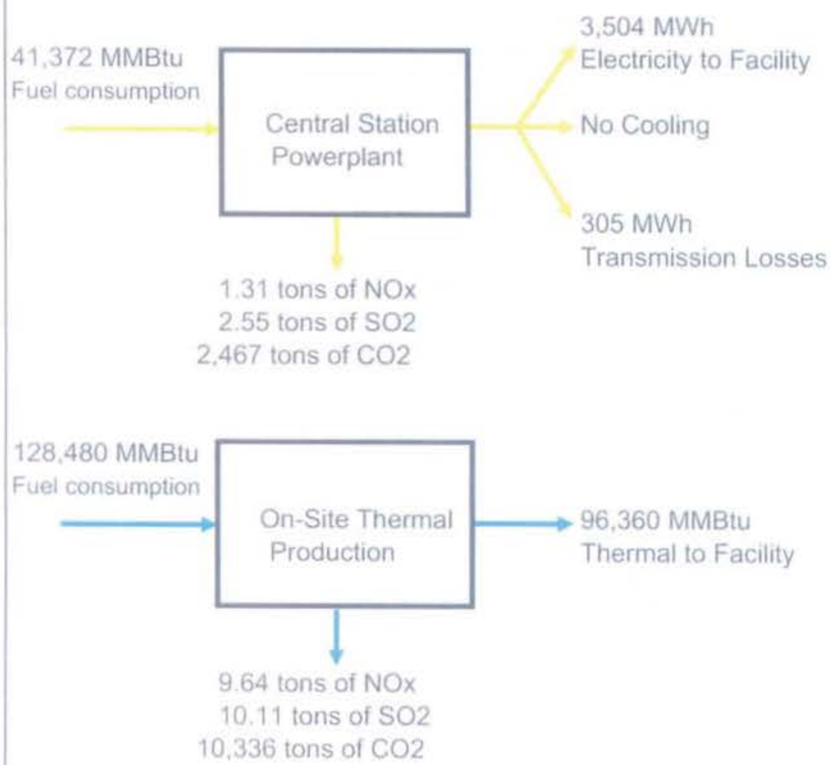
Large Tri-Gen - 600 kW Back-Pressure Steam-Turbine-Generator

Combined Cycle Model

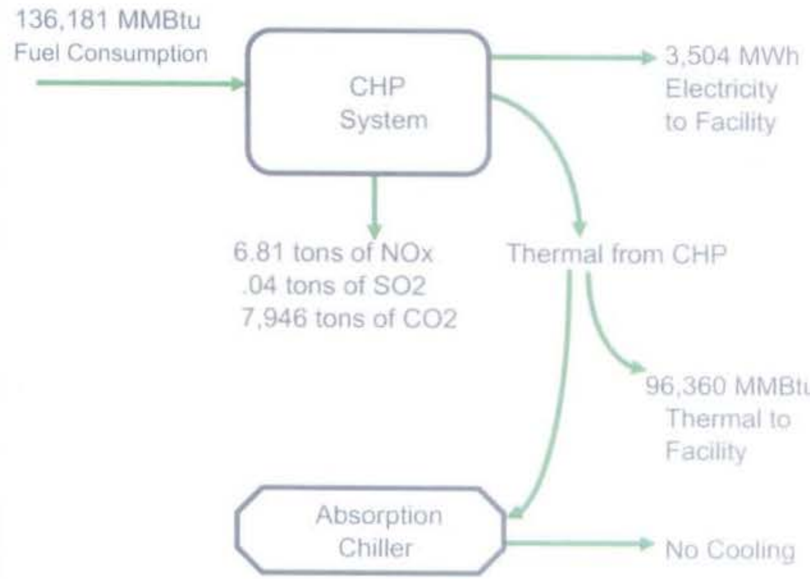
Note: Energy Source is excess waste steam for combined-cycle model, not NG.

CHP Results

Total Emissions for Conventional Production
10.94 tons of NOx
12.66 tons of SO2
12,803 tons of CO2



Total Emissions for CHP System
6.81 tons of NOx
.04 tons of SO2
7,946 tons of CO2



Note: Energy Source is excess waste steam for combined-cycle model, not NG.

CHP Results

Emission Rates	CHP System including Duct Burners	Backpressure Steam Turbine Alone	Displaced Electricity
NOx (lb/MWh)	3.89	3.89	0.69
SO2 (lb/MWh)	0.02	0.02	1.34
CO2 (lb/MWh)	4,535	4,535	1,295

Emission Rates	Displaced Thermal Production
NOx (lb/MMBtu)	0.15
SO2 (lb/MMBtu)	0.15735
CO2 (lb/MMBtu)	161

Privileged and Confidential Information of Self-Gen, Inc.

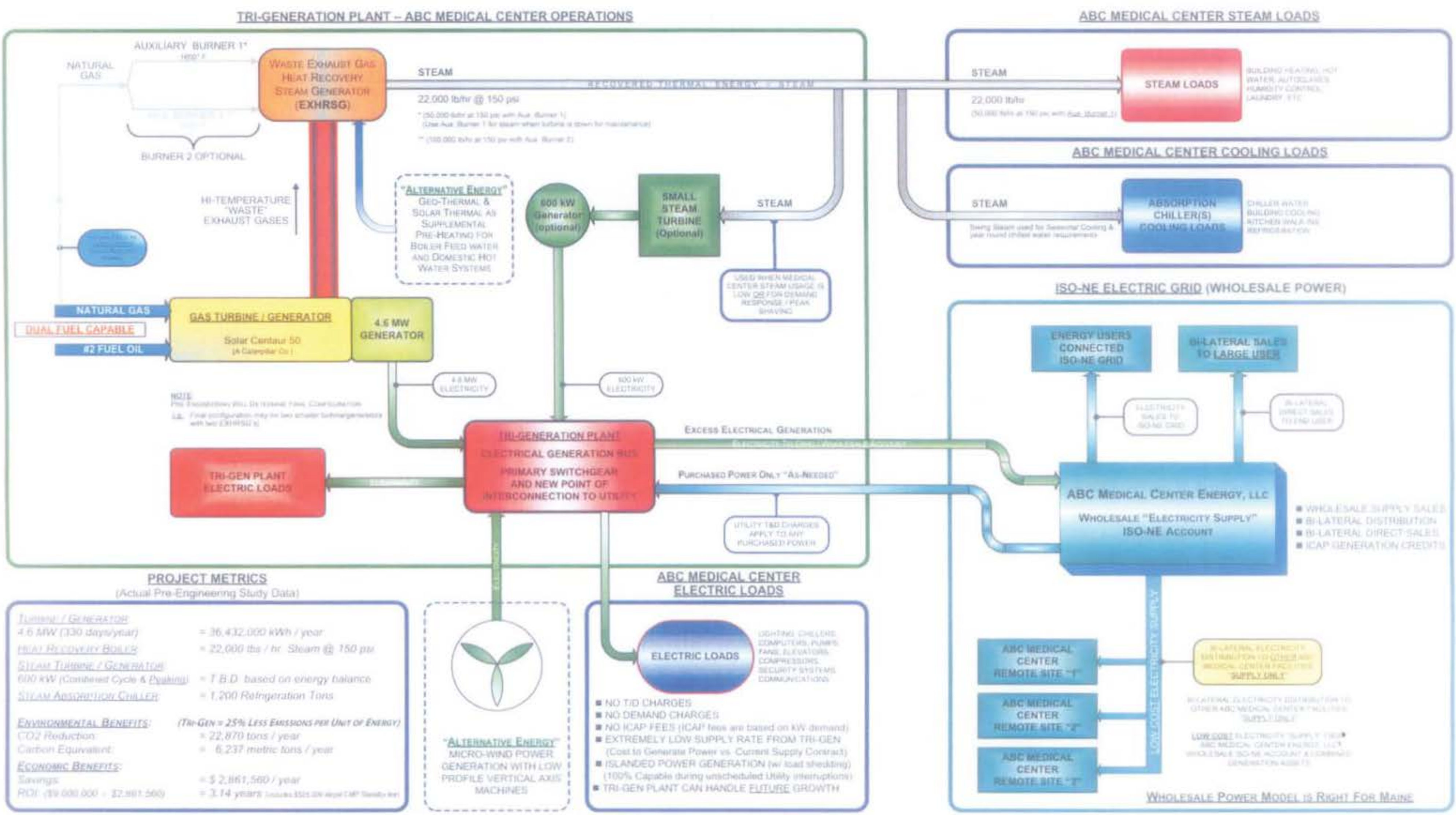
Self-Gen
Integrated energy solutions & services
www.self-gen.com

ABC Medical Center - Tri-Generation Energy Model

Privileged and Confidential Information of Self-Gen, Inc.

Self-Gen
Integrated energy solutions & services
www.self-gen.com

25% Less Harmful Emissions With the Tri-Generation Energy Model



ENERGY BALANCE TABLE

Without Tri-gen (SHP)

ELECTRICITY – "WITHOUT" TRI-GEN

DEBITS

Existing Usage:
30,000,000 kWh / year x $ 0.14/kWh = **$ 4,200,000 / yr**

New Expansion:
4,257,360 kWh / year x $ 0.14/kWh = $ **596,030 / yr**
Assumes:
(4.5 Watts / sq. ft; 180,000 sq. ft.; 60% / Duty cycle)
(plug power, lighting, Fans, Pumps)
4.5 watts / sq. ft. x 180,000 sq. ft. = 810,000 watts
810,000 watts x 0.60 Duty Cycle = 486,000 watts
486,000 watts x 24 hrs/day x 365 days/yr = 4,257,360,000 Wh/yr
4,257,360,000 watt/hrs ÷ 1,000 watts / kW = 4,257,360 kWh / yr

New Chillers (74% Increase):
3,023,076 kWh / yr x $ 0.14/kWh = $ **423,230 / yr**
3990 Tons New – 2290 Tons Existing = 1700 Tons **New Load**
1700 Added Tons x 0.58 kWe / Ton = 986 kWe
986 kWe x 24 hr / day x 70% Run Time = 16,564.8 kWh / day
16,564.8 kWh / day x 182.5 days/yr = 3,023,076 kWh / yr
*Erring on the side of Non-Tri-gen assume **50% or 182.5** days/year*
(Duty Cycle Data for Chiller Loads is not available)

Utility (T&D Standby Fee – illegal per deregulation):
T&D charges are already included in the $ 0.14 / kWh cost for the all kWh consumed and kW demand charges. There is no Standby Fee for the CUP. We assume the MC T&D charge per kWh is a negotiated rate of $ 0.015, which is typical for large users, but no data supporting this has been provided to us.

CREDITS

CREDITS FOR

SEPARATE HEAT & POWER (SHP) ENERGY MODEL (Non-Tri-gen)

NONE

(37,280,436 kWh / year estimated)

TOTAL PROJECTED ELECTRICITY COSTS FOR - NON-TRI-GEN

$ 5,219,260 - Debit (Non-Tri-gen - Annual Cost)

Electricity Cost **Savings** with **Tri-generation**: **$ 2,361,068**

Comprehensive Pre-Engineering will refine these values

With Tri-gen (CCHP)

ELECTRICITY – "WITH" TRI-GEN (CCHP)

DEBITS

Existing Usage:
30,000,000 kWh / year x $ 0.14/kWh = **$ 4,200,000 / yr**

New Expansion:
4,257,360 kWh / year x $ 0.14/kWh = $ **596,030 / yr**
Assumes:
(4.5 Watts / sq. ft; 180,000 sq. ft.; 60% / Duty cycle)
(plug power, lighting, Fans, Pumps)
4.5 watts / sq. ft. x 180,000 sq. ft. = 810,000 watts
810,000 watts x 0.60 Duty Cycle = 486,000 watts
486,000 watts x 24 hrs/day x 365 days/yr = 4,257,360,000 Wh/yr
4,257,360,000 watt/hrs ÷ 1,000 watts / kW = 4,257,360 kWh / yr

New Chillers (74% Increase):
3,023,076 kWh / yr x $ 0.14/kWh = $ **423,230 / yr**
3990 Tons New – 2290 Tons Existing = 1700 Tons **New Load**
1700 Added Tons x 0.58 kWe / Ton = 986 kWe
986 kWe x 24 hr / day x 70% Run Time = 16,564.8 kWh / day
16,564.8 kWh / day x 182.5 days/yr = 3,023,076 kWh / yr
*Erring on the side of Non-Tri-gen assume **50% or 182.5** days/year*
(Duty Cycle Data for Chiller Loads is not available)

Utility (T&D Standby Fee – questionable per deregulation):
35,000,000 kWh / yr x $ 0.015 / kWh = $ **525,000 / yr**
Assume: *(Bangor EMMC budgeted $ 300,000 for their Tri-gen)*
A standby fee equal to T&D charges for **ALL** kWh consumed for 2006 will be used however, this is a very inflated number based on rulings with the Maine PUC, however we don't want it to be a point for "misleading" MC leadership (fee is questionable).

CREDITS

New Tri-generation 4.6 MW of Generation:
37,280,436 kWh/yr x $ **0.062** / kWh = **$ 2,311,387 / yr**
($ 0.078 / kWh – Electric Gen. Costs; $ 0.042 / kWh Thermal Cost)
*($ 0.14 / kWh – $ 0.076 / kWh = $ 0.062 / kWh - **Savings**)*
2,463,564 kWh/yr x $ 0.06/kWh (Wholesale Bank) = $ **147,814 / yr**
(ABC Energy, LLC sells power to ABC facilities at $ 0.08 / kWh, saving the current ABC facility $ 0.06 / kWh from current Electricity prices)
4.6 MW x 24 hrs/day x 360 days/yr = 39,744,000 kWh/yr
(39,744,000 – 37,280,436 = 2,463,564 kWh) *(Total Generation)*

New Chillers (Steam Absorption Chiller Offset):
$ 2,339 / day x 182.5 days = $ **426,867 / yr**
50 % of 365 days / year *(cooling per utility kW)* = 182.5 days / year
(The seasonal increase time frame is taken Directly from utility Electric kW Profile and the MC Steam Measure Steam flow Data Profiles)
5.5 MW (cooling season) – 3.2 MW (heating season) = 2.3 MW or 2300 kW
Assumes "All" of the 2300 kW increase is for Chillers
2300 kW (cooling season) ÷ 0.58 kW/Ton = **3,965 Tons Cooling**
1200 Ton Steam Chiller x 0.58 kWe / Ton = 696 kWe
696 kWe x 24 hr / day = 16,704 kWh / day
(Assume 100 % Run Time to Base Load 3,965 Tons Required)
16,704 kWh / day x $ 0.14 / kWh = $ **2,339 / day**

Back-Pressure Turbine / Generators "Before" Chillers:
During the pre-engineering phase we will look at utilizing back pressure turbine/generators for prior to each steam chiller as a "PRV" station.

TOTAL PROJECTED ELECTRICITY COSTS "TRI-GEN"

$ 5,744,260 - Debit
$ 2,886,068 - Less Credits
$ 2,858,192 - Debit (Tri-gen Annual Costs)

Comprehensive Pre-Engineering will refine these values

ENERGY BALANCE TABLE

Without Tri-gen (SHP)

THERMAL (HEATING) – "WITHOUT" TRI-GEN

DEBITS

Existing Natural Usage (Year Round & Heating):
1,300,000 therms/year x $ 1.20/therm = **$ 1,560,000 / yr**
2005 - Actual Usage:
1,276,944 ccf /yr x 100 (c) = 127,694,400 cf /yr
127,694,400 cf/yr x 1000 btu/cf (nat. gas) = 127,694,400,000 btu/yr
127,694,400,000 btu/yr ÷ 100,000 btu/therm = 1,276,944 therm/yr
Assume a slight increase per historical data: = 1,300,000 therm/yr

(NYMEX gas prices today are at $ 0.71/therm, plus add-ins, No volume discount, but discount from Current $ 1.45 therm rate)

New Building Natural Gas Usage (Heating Months):
175,200 therms/year x $ 1.20/therm = **$ 210,240 / yr**
Assumes:
180,000 sq. ft. bldg, 4 floors, Rule-of-Thumb = 4,000,000 btu/hr
4,000,000 btu / hr. x 24 hrs/day = 96,000,000 btu/day
96,000,000 btu/day x 182.5 days / year = 17,520,000,000 btu/yr
17,520,000,000 btu/yr ÷ 100,000 btu/therm = 175,200 therms/yr

Fuel Oil – Existing Usage:
310,000 / gals. / year x $ 1.97 / therm = $ 610,700
(assumes 2006 fuel oil rate of $ 1.97 / gal)

TOTAL PROJECTED "THERMAL" (HEATING) COSTS for "NON-TRI-GEN" (SHP)

$ 2,380,940 – (Annual Cost w/out Cogen)

SAVINGS PER YEAR IN "THERMAL" (HEATING)

$ 2,380,940 – Without Tri-gen Model
$ 1,880,448 – With Tri-gen (CCHP) Model
$ 500,492 – Thermal Savings/Year With Tri-gen

Comprehensive Pre-Engineering will refine these values

With Tri-gen (CCHP)

THERMAL (HEATING) – "WITH" TRI-GEN (CCHP)

DEBITS

Tri-gen Natural Usage (Year Round – Electricity, Heating, & Cooling):
39,744,000 kWh/yr x $ 0.042 / kWh = **$ 1,669,248 / yr**
Assumes:
*($ 0.078 / kWh – Electric Gen. Costs; **$ 0.042 / kWh Thermal Cost**)*

(NYMEX (www.nymex.com) gas prices today are at $ 0.71/therm, plus add-ins and "Volume Discounting" on Supply and T&D rates)

New Building Natural Gas Usage (Heating Months):
175,200 therms/year x $ 1.00/therm = **$ 175,200 / yr**
Assumes:
180,000 sq. ft. bldg, 4 floors, Rule-of-Thumb = 4,000,000 btu/hr
4,000,000 btu / hr. x 24 hrs/day = 96,000,000 btu/day
96,000,000 btu/day x 182.5 days / year = 17,520,000,000 btu/yr
17,520,000,000 btu/yr ÷ 100,000 btu/therm = 175,200 therms/yr

Aux. Burner 1 Rated for Max. output of 26.13 MMBtu for a HRSG total steam output of 50,000 PPH steam output used for "Peak Steam Loading" and "New Expansion" steam loads as needed.

"Avg. Peak" Steam Loads – Using HRSG Aux. Burner (Heating Months):
36,000 therms/year x $ 1.00/therm = **$ 36,000 / yr**
Assumes:
4,000,000 btu / hr. x 10 hrs/day (peaking profile) = 40,000,000 btu/day
40,000,000 btu/day x 90 days / year = 3,600,000,000 btu/yr
3,600,000,000 btu/yr ÷ 100,000 btu/therm = 36,000 therms/yr

Per Steam Usage flow Measurements: Jan, Feb., & March require more than 22,000 PPH Steam flow, the Cogen. HRSG will have an Aux. Burner 1 to make-up the difference during these 3 months. Aux. Burner 1 is rated at 26.13 MMBtu/hr for a max of 50,000 PPH Steam as needed for "peaking" and "the Expansion" loads.

TOTAL PROJECTED "THERMAL" (HEATING) COSTS for TRI-GEN (CCHP)

$ 1,880,448 – (Annual Cost With Tri-gen)

Comprehensive Pre-Engineering will refine these value

CORE TRI-GENERATION - ENERGY BALANCE – SPRING 2006
FOUNDATIONAL CALCULATIONS

Turbine / Generator "Fuel" Requirement:
50 MMBtu/hr or 500 Therms / hr per manufacturer @ 100% output

Turbine / Generator "Running" Costs:

(500 therms / hr ÷ 4600 kW) x $1.00 / therm	= $ 0.1090 / kWh	*(Quoted Gas Pricing, also NYMEX is a $ 0.71 / therm)*
Maintenance Costs per kWh Generated:	= $ 0.0040 / kWh	
Misc. Operating Costs: *($ 278,000 / yr. misc.)*	= $ 0.0070 / kWh	*(added to 0.113 / kWh to round-up to 0.12 / kWh)*
Total Turbine / Generator "Running" Costs:	**= $ 0.1200 / kWh**	

Total Turbine / Generator "Running" Costs @ 100%:
$ 0.120 / kWh x 4,600 kW = **$ 552 / hr**

MC's "THERMAL" Costs for 2005 (Heating): *(This value can vary based on Energy profiles and can be Optimized)*

From MC Energy Usage, 2005 Thermal Usage	= 170,374.0 MMBtu/yr **or** (19.4 MMBtu / hr)	
From MC Energy Usage, 2005 Thermal Costs:	= $ 9.83 / MMBtu	
19.4 MMBtu/hr x $ 9.83 / MMBtu	= **$ 190.0 / hr**	(Total Heating Thermal Energy Costs for 2005)

Turbine/Generator "Electrical Energy" Costs per kWh Generated:

$ 552 /hr (Total Oper. Cost) - $ 190 / hr (Thermal Costs)	= $ 362 / hr	
$ 362 / hr ÷ 4,600 kW	= **$ 0.078 / kWh**	(**Electricity** Generation Cost for Tri-gen Model)

Turbine/Generator "Thermal Energy" Costs per kWh Generated:
$ 0.12 kWh (Total Cost) - $ 0.078 kWh (Electric Gen. Cost) = **$ 0.042 / kWh** (**Thermal** Generation Cost for Tri-gen Model)

SIMPLE PAYBACK SUMMARY FOR TRI-GENERATION (CCHP):

$ 2,361,068 – Electricity Savings with Tri-gen (CCHP)
$ 500,492 – Thermal Savings with Tri-gen (CCHP)
$ 2,861,560 $ 9,000,000 ÷ $ 2,861,560 = **3.14 Year Simple Payback** (including Utility Standby Fee of $ 525,000)

APPENDIX E: CHP FACILITIES IN MAINE

Combined Heat and Power Units located in Maine

(Source: http://www.eea-inc.com/chpdata/States/ME.html)

State	City	Organization Name	Facility Name	Application	SIC4	NAICS	Op Year	Prime Mover	Capacity (kw)	Fuel Type
ME	Auburn	Mid-Maine Waste Action Corp	Mmwac Resource Recovery Facility	Solid Waste Facilities	4953	562212	1992	B/ST	5,000	WAST
ME	Bangor	Eastern Maine Medical Center	Eastern Maine Medical Center	Hospitals/Healthcare	8062	62211	2005	CT	4,400	NG
ME	Bangor	Auto Dealership	Auto Dealership	Automotive Services	5511	44111	2004	MT	60	NG
ME	Bethel	P. H. Chadbourne & Co.	P. H. Chadbourne & Co.	Wood Products	2411	11331	1987	B/ST	1,814	WOOD
ME	Bucksport	Bucksport Energy LLC	International Paper/ Champion Clean Energy	Pulp and Paper	2600	322	1988	B/ST	251,000	NG
ME	Hinckley/Skowhegan	Sappi / S.D. Warren/Scott Paper Company	S.D. Warren Somerset Mill	Pulp and Paper	2621	322121	1976	B/ST	113,000	WAST
ME	Jay	International Paper Company	Androscoggin Mill	Pulp and Paper	2621	322121	1965	B/ST	80,000	WAST
ME	Jay	Wassau-Moisinee	Wassau-Moisinee	Pulp and Paper	2621	322121	2001	B/ST	2,821	OIL
ME	Jay	Calpine - Androscoggin Energy LLC	Androscoggin Energy Center	Pulp and Paper	2621	322121	1999	CT	163,500	NG
ME	Kittery	U.S. Navy	Portsmouth Naval Ship Yard (ESPC #1)	Military/National Security	9711	92811	2000	CT	10,500	NG
ME	Kittery Point	Residential Project	Residential Cogeneration System	Private Households	8811	81411	1992	ERENG	5	OIL
ME	Lewiston	Corporate Energy Management ,Nc	Bates Energy Associates	Colleges/Univ.	8221	61131	1986	B/ST	1,125	WOOD
ME	Lincoln	Lincoln Pulp And Paper Company	Lincoln Sawmill	Wood Products	2421	321113	1991	B/ST	2,940	WAST
ME	Madawaska	Fraser Paper, Ltd.	Fraser Paper, Ltd.	Pulp and Paper	2621	322121	1989	B/ST	20,000	OTR
ME	Madison	Madison Paper Industries Inc	Anson Abenaki Hydros	Pulp and Paper	2621	322121	1994	B/ST	3,000	OIL
ME	Mattawamkeag	Aroostook & Bangor Reload Co	Aroostook Bangor Reload Co Perma Treat Plant	Wood Products	2421	321113	1992	B/ST	1,000	WOOD
ME	Old Town	Old Town Fuel and Fiber (Former James River Paper Company)	Old Town Fuel and Fiber (Former James River Corporation)	Pulp and Paper	2621	322121	1946	B/ST	19,300	NG
ME	Penobscot	Great Northern Paper/Inexcon Maine	Millinocket Thermal Facilities	Pulp and Paper	2621	322121	1957	B/ST	95,100	OIL
ME	Penobscot	Great Northern Paper Inc	East Millinocket	Pulp and Paper	2621	322121	1954	B/ST	61,400	WOOD
ME	Rumford	Boise Cascade Corporation	Boise Cascade Corporation	Pulp and Paper	2621	322121	1955	B/ST	10,000	NG
ME	Rumford	Rumford Cogen Company	Mead Paper Company	Pulp and Paper	2621	322121	1990	B/ST	85,000	COAL
ME	Sanford	Lavalley Lumber LLC	Lavalley Lumber LLC	Wood Products	2421	321113	1989	B/ST	1,500	WOOD
ME	Searsmont	Robbins Lumber Inc	Robbins Lumber Inc	Wood Products	2421	321113	1981	B/ST	1,250	WOOD
ME	Sherman Station	Wheelabrator Sherman Energy/Duke Solutions	Sherman Lumber Company/Stacyville	Wood Products	2421	321113	1986	B/ST	21,000	WOOD
ME	Strong	Forster Manufacturing Co Inc/Diamond Brands	Forster Manufacturing Co Inc.	Wood Products	2400	321	1979	B/ST	1,300	WOOD
ME	Waterville	Colby College	Colby College	Colleges/Univ.	8221	61131	1999	B/ST	600	OIL
ME	Westbrook	Sappi / S.D. Warren/Scott Paper Company	S.D. Warren Division / Westbrook	Pulp and Paper	2621	322121	1965	B/ST	62,500	WOOD
ME	Woodland	Georgia-Pacific Corporation	Georgia-Pacific Corporation	Pulp and Paper	2621	322121	1966	B/ST	44,500	WAST
ME	Woodland	Georgia-Pacific Corporation	Woodland OSB Plant	Pulp and Paper	2631	32213	1977	B/ST	67,200	WOOD

Prime Mover Code	Description		Fuel Code	Description
B/ST	Boiler/Steam Turbine		BIOMASS	Biomass, LFG, Digester Gas, Bagasse
CC	Combined Cycle		COAL	Coal
CT	Combustion Turbine		NG	Natural Gas, Propane
FCEL	Fuel Cell		OIL	Oil, Distillate Fuel Oil, Jet Fuel, Kerosene, RFO
MT	Microturbine		WAST	Waste, MSW, Black Liquor, Blast Furnace Gas, Petroleum Coke, Process Gas
ERENG	Reciprocating Engine		WOOD	Wood, Wood Waste
OTR	Other		OTR	Other

State Summary for Maine

Prime Mover Code	Sites	Capacity (kW)
Total	29	1,130,815
B/ST	24	952,350
CC	0	0
CT	3	178,400
FCEL	0	0
MT	1	60
OTR	0	0
ERENG	1	5

Additional CHP Facility: Old Town/Orono YMCA - 65 kW Capstone Micro-Turbine CHP system (Source: Bill Lovejoy - Project Manager/Board Member)

APPENDIX F: CHP INCENTIVES

Appendix F
Incentives and Funding Programs

Name	Type	Description	Expiration Date
CHP Investment Tax Credit (ITC)	Tax	The Emergency Economic Stabilization Act 0f 2008, enacted on October 3, 2008, created a new investment tax credit (ITC) for CHP and waste energy recovery systems. The CHP ITC extends from the date of enactment through December 31, 2016. The American Recovery and Reinvestment Act of 2009 (ARRA), enacted February 2009, allows taxpayer eligibility for the CHP ITC to receive a grant from the U.S. Treasury Department instead of taking the business ITC from new installations. For eligible CHP projects, Treasury will make payments to qualified applicants in an amount equal to 10% of the system cost. The Treasury Department is now accepting applications for the grant program. For more information including the guidance document (PDF), terms and conditions (PDF), and a sample application (PDF), please visit the U.S. Department of Treasury's Web site. To apply for a grant in lieu of the tax credit, please visit the application web site. EIEA created a 10% investment tax credit (ITC) for the costs of the first 15 MW of CHP property. To qualify for the tax credit, the CHP system must: • Produce at least 20% of its useful energy as electricity and 20% as thermal energy; • Be smaller than 50 MW; • Be constructed by the taxpayer or have the original use of the equipment begin with the taxpayer; • Be placed in service after October 3, 2008 and before January 1, 2017; and • Be 60% efficient on a lower heating value basis. The 60% efficiency requirement does not apply to CHP systems that use biomass for at least 90% of the system's energy source. The ITC may be used to offset the alternative minimum tax and the CHP system must be operational in the year in which the credit is first taken. The CHP ITC is claimed through IRS Form 3468, available on the IRS's Web site. Facility owners who claim the ITC can not claim the production tax credit (PTC).	01/01/2017
Investment Tax Credits for Micro-Turbines and Fuel Cells	Tax	The EIEA extended the ITC to micro-turbines and fuel cells. For micro-turbines, the credit is equal to 10% of expenditures, with no maximum limit stated (explicitly), but it is capped at $200 per kW of capacity. Eligible property includes micro-turbines up to two MW that have an electricity-only generation efficiency of 26% or higher. For fuel cells, the credit is equal to 30% of expenditures, with no maximum credit. However, the credit for fuel cells is capped at $1,500 per 0.5 kW of capacity. Eligible property includes fuel cells with a minimum capacity of 0.5 kW that have an electricity-only generation efficiency of 30% or higher. (The credit for property placed in service before October 4, 2008, is capped at $500 per 0.5 kW.) The ITC for both micro-turbines and fuel cells is available for eligible systems placed in service on or before December 31, 2016. As with the CHP ITC, facility owners can choose to receive a one-time grant equal to 30% of the construction and installation costs for the facility, as long as the facility is depreciable or amortizable. To be eligible, the facility must be placed in service in 2009 or 2010, or construction must begin in either of	None

Name	Type	Description	Expiration Date
		those years and be completed prior to the end of 2013. For more information including the guidance document, terms and conditions and a sample application, please visit the U.S. Department of Treasury's Web site. To apply for a grant in lieu of the tax credit, please visit the application web site. The ITC for micro-turbines and fuel cells is claimed through IRS Form 3468, available on the IRS's Web site. Facility owners who claim the ITC can not claim the production tax credit (PTC).	
Renewable Electricity Production Tax Credit	Tax	The EIEA extended the PTC for biomass, geothermal, hydropower, landfill gas, waste-to-energy, and marine facilities and other forms of renewable energy through 2010, and the ARRA further extended the tax credit through 2013. The renewable electricity PTC is a per kWh federal tax credit included under Section 45 of the U.S. tax code for electricity generated by qualified energy resources. The PTC provides a corporate tax credit of 1.0 cents/kWh for landfill gas, open-loop biomass, municipal solid waste resources, qualified hydropower, and marine and hydrokinetic (150 kW or larger). Electricity from wind, closed-loop biomass, and geothermal resources receive 2.1 cents/kWh. Projects that receive other government grants or subsidies receive a discounted tax credit. The ARRA allows taxpayers eligible for the federal PTC to take the federal business energy investment tax credit (ITC) or to receive a grant from the U.S. Treasury Department instead of taking the PTC for new installations. The Treasury Department issued Notice 2009-52 in June 2009, giving limited guidance on how to take the federal business energy investment tax credit instead of the federal renewable electricity production tax credit. The Treasury Department is now accepting applications for the grant program. For more information including the guidance document, terms and conditions and a sample application, please visit the U.S. Department of Treasury's Web site. The Renewable Energy PTC is claimed through IRS Form 8835 and IRS Form 3800.	2013
Bonus Depreciation	Tax	Under the federal Modified Accelerated Cost-Recovery System (MACRS), businesses may recover investments in certain property through depreciation deductions. The MACRS establishes a set of class lives for various types of property, ranging from three to 50 years, over which the property may be depreciated. The ARRA extended the five-year bonus depreciation schedule through 2010 and includes CHP, thereby allowing 50% of the depreciation value to be taken in the first year and the remainder over the following four years. To qualify for bonus depreciation, a project must satisfy these criteria: • The property must have a recovery period of 20 years or less under normal federal tax depreciation rules; • The original use of the property must commence with the taxpayer claiming the deduction; • The property generally must have been acquired during 2009 or 2010; and • The property must have been placed in service during 2009 or 2010. The bonus depreciation rules do not override the depreciation limit	2010

Name	Type	Description	Expiration Date
		applicable to projects qualifying for the federal business energy tax credit. Before calculating depreciation for such a project, including any bonus depreciation, the adjusted basis of the project must be reduced by one-half of the amount of the energy credit for which the project qualifies. For more information on the federal MACRS, see IRS Publication 946, IRS Form 4562: Depreciation and Amortization, and Instructions for Form 4562.	
Advanced Energy Manufacturing Tax Credit	Tax	ARRA established the advanced energy manufacturing tax credit to encourage the development of a U.S.-based renewable energy manufacturing sector. ARRA authorizes the Department of the Treasury to issue $2.3 billion of credits under the program. In any taxable year, the investment tax credit is equal to 30% of the qualified investment required for an advanced energy project that establishes, re-equips, or expands a manufacturing facility that produces any of the following: • Equipment and/or technologies used to produce energy from solar, wind, geothermal, or other renewable resources; • Fuel cells, micro-turbines, or energy-storage systems for use with electric or hybrid-electric motor vehicles; • Equipment used to refine or blend renewable fuels; or • Equipment and/or technologies to produce energy-conservation technologies (including energy-conserving lighting technologies and smart grid technologies). Qualified investments generally include personal tangible property that is depreciable and required for the production process. Other tangible property may be considered a qualified investment only if it is an essential part of the facility, excluding buildings and structural components. To be eligible for the tax credit, a project must be certified by the Department of the Treasury. In determining which projects to certify, ARRA directs the Department of the Treasury to consider those projects that most likely will: • Be commercially viable; • Provide the greatest domestic job creation; • Provide the greatest net reduction of air pollution and/or greenhouse gases; • Have the greatest potential for technological innovation and commercial deployment; • Have the lowest levelized cost of generated (or stored) energy or the lowest levelized cost of reduction in energy consumption or greenhouse gas emissions; and • Have the shortest project time from certification to completion. After certification is granted, the taxpayer has up to one year to provide additional evidence that the requirements of the certification have been met and three years to put the project in service. On August 13, 2009, the Department of the Treasury announced the availability of funds under the program and preliminary applications were due to DOE September 16, 2009, followed by final applications being due to DOE and IRS on October 16, 2009. By January 15, 2010, the IRS certified or rejected applications, and notified the certified projects with the approved amount of their tax credit. Awardees received acceptance agreements from the IRS by April 16, 2010. Credits will be allocated until the program funding	01/01/2017

Appendix F
Incentives and Funding Programs

Name	Type	Description	Expiration Date
		is exhausted. Subsequent allocation periods will depend on remaining funds.	
Clean Renewable Energy Bonds	Tax	The 2005 Energy Policy Act created Clean Renewable Energy Bonds (CREBs) within Section 54 of the U.S. tax code. Unlike traditional bonds that pay interest, tax credit bonds pay the bondholders by providing a credit against their federal income tax. In effect, CREBs provide interest-free financing for clean energy projects. In 2008, EIEA provided authority for the issuance of an additional $800 million in "new" CREBs, and in 2009, ARRA allocated an additional $1.6 billion for CREBs. The 2008 legislation also extended the deadline by which bonds must be issued for previous allocations to December 31, 2009. The types of projects for which bonds can be issued include renewable energy projects utilizing landfill gas, wind, biomass, geothermal, solar, municipal solid waste, small hydroelectric, marine, and hydrokinetic. The IRS has determined that facilities "functionally related and subordinate" to the generation facility itself are also eligible for CREB financing. Examples of these auxiliary components include transmission lines and interconnection upgrades. The EIEA directs the IRS to allocate the bonding authority equally among electric cooperatives, government entities, and public power producers. Other changes for "new" CREBs are as follows: • The federal tax credit is reduced to 70% of the interest payment; • The bond holder can transfer the tax credit to another party; • Taxpayers can carry forward unused credits into future years; and • Bond proceeds must be used within three years or a request for an extension must be made.	
Qualified Energy Conservation Bonds	Tax	The EIEA created a new funding mechanism called Qualified Energy Conservation Bonds (QECBs), similar to the CREB model in which a bondholder receives tax credits in lieu of interest. The act authorizes state, local, and tribal governments to issue energy conservation bonds to finance qualified projects. The 2008 legislation allows the IRS to distribute up to $800 million in bond authorizations. In 2009, ARRA provided an additional $2.4 billion in bonding authority. The bond proceeds can be used to finance capital expenditures that achieve one of the following goals: • Reduction of energy consumption by at least 20%; • Implementation of a green community program; or • Electricity generation from renewable resources in rural areas. An IRS notice contains more details about the bond program, including an outline for the bond cap for each state. The IRS is expected to issue further guidance on how the program will work soon.	None
Deployment of CHP Systems, District Energy Systems, Waste Energy Recovery Systems, and Efficient Industrial Equipment	Grant	On June 1, 2009 the DOE announced plans to provide $156 million from ARRA to support projects that deploy efficient technologies in the following four areas of interest: • CHP; • District energy systems; • Industrial waste energy recovery; and • Efficient industrial equipment. Applications were due by July 15, 2009. On November 3, 2009, the DOE announced its award of more than $155	

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		million to 41 industrial energy efficiency projects across the country. The nine largest projects, totaling $150 million and leveraged with $634 million in private industry support, will promote the use of CHP, district energy systems, waste energy recovery systems, and energy efficiency initiatives at hospitals, utilities, and industrial sites. A full list of recipients is available on the DOE's Industrial Technology Program Web site.	
Combined Heat and Power Systems Technology Development Demonstration	Grant	The Combined Heat and Power Systems Technology Development Demonstration aims to accelerate the development and deployment of CHP technologies and systems to work towards a goal of increasing U.S. electricity generation capacity from CHP. Applications for CHP technology development and demonstration will be considered for three areas of interest. The areas of interest are based on the output range of the CHP system and are as follows: • Large CHP systems (less than or equal to 20 MW); • Medium CHP systems (less than or equal to 1 MW to greater than 20 MW); and • Small CHP systems (less than or equal to 5 kW to greater than 1 MW). All three areas sought applicants that can perform research, development, and demonstration of technologies that increase the efficiency and reduce the cost of CHP systems. Applications were due by August 4, 2009. The large CHP systems have an estimated total budget of $30 million – $15 million from the DOE. The medium systems have an estimated budget of $30 million – $15 million from the DOE. Small CHP systems have an estimated budget of $20 million – $10 from the DOE. Funded demonstration projects are aimed at accelerating the project development process through collaborative partnerships with key industry partners. Key technologies are those capable of sizable energy savings and corresponding greenhouse gas emissions reductions while providing a least cost approach to compliance with relevant emissions regulations. All technologies have a defined pathway to commercialization.	
Waste Energy Recovery Registry and Grant Program	Grant	Title IV of the Energy Independence and Security Act of 2007 contains extensive new provisions designed to save energy in buildings and industries. Subtitle D of the Act focuses on industrial energy efficiency and contains new provisions designed to improve energy efficiency by promoting CHP, waste energy recovery, and district energy systems. EPA is required under EIEA Subtitle D, Part E to establish a recoverable waste energy inventory program. Subject to appropriations, the EIEA also directs the DOE to develop a waste energy recovery incentive grant program to provide incentive grants to: • Owners and operators of projects that successfully produce electricity or incremental useful thermal energy from waste energy recovery; • Utilities purchasing or distributing the electricity; and • States that have achieved 80% or more of recoverable waste heat recovery opportunities. US EPA's obligation under EISA is to develop an ongoing survey of major	

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<tr><th>Name</th><th>Type</th><th>Description</th><th>Expiration Date</th></tr>
<tr><td></td><td></td><td>domestic industrial and large commercial sources, as well as the sites at which the sources are located, and to conduct a review of each source for the quantity and quality of potential waste energy produced. This survey is a necessary first step to gather the data needed to establish the Registry of Recoverable Waste Energy Sources (Registry). The purposes of the survey and Registry are to:
• Provide a list of the economically feasible existing waste energy recovery opportunities in the US, based on a survey of major industrial and large commercial sources.
• Provide state and national totals of the existing waste energy recovery opportunities, as well as the potential criteria pollutant and greenhouse gas emissions reductions that could be achieved with the capture and use of the waste energy recovery opportunities listed in the Registry.
• Serve as the basis for potential waste energy recovery projects to qualify for financial and regulatory incentives as described in Energy Policy and Conservation Act (EPCA) Sections 373 "Waste Energy Recovery Incentive Grant Program" and 374 "Additional Incentives for Recovery, Use, and Prevention of Industrial Waste Energy," as added by EISA.

On July 16, 2009, the US EPA Administrator signed a draft rule which proposes to establish the criteria for including sources or sites in the Registry, as required by EISA. The draft rule also proposes the survey processes by which US EPA will collect data and populate the Registry. The proposed rule would apply to major industrial and large commercial sources as defined by US EPA in the rulemaking. The proposed rule would not require the installation of new monitoring equipment, rather it would require only that sources above certain threshold levels that wish to be included in the Registry enter specific already-monitored data points into the survey. The survey is a software tool that will calculate the quantity and quality of potentially recoverable waste energy.

The proposed rule and relevant background information can be accessed on the Waste Energy Recovery Registry Web site. Public comments were accepted through September 21, 2009. For general questions about the proposed rule, contact Katrina Pielli.</td><td></td></tr>
<tr><td>EPA Clean Water and Drinking Water State Revolving Funds</td><td>Grant</td><td>ARRA provides funding for states to finance high-priority infrastructure projects needed to ensure clean water and safe drinking water. It provided $4 billion for the Clean Water State Revolving Fund (CWSRF) program, in place since 1987, including funds for Water Quality Management Planning Grants. ARRA also provided $2 billion for the Drinking Water State Revolving Fund (DWSRF) program, in place since 1997. States must provide at least 20% of their grants for green projects, including green infrastructure, energy or water efficiency, and environmentally innovative activities. CHP projects at wastewater treatment facilities qualify for grants under the 20% set-aside.

The CWSRF program is available to fund a wide variety of water quality projects, including all types of nonpoint source, watershed protection or restoration, and estuary management projects, as well as more traditional municipal wastewater treatment projects. Through the CWSRF program, each state and Puerto Rico maintain revolving loan funds to provide independent and permanent sources of low-cost financing for a wide range</td><td></td></tr>
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		of water quality infrastructure projects. Funds to establish or capitalize the CWSRF programs are provided through federal government grants and state matching funds (equal to 20% of federal government grants). The DWSRF program provides public water systems with affordable financing for infrastructure improvements which enable them to comply with national primary drinking water standards and protect public health. States use federal capitalization grant money awarded to them under this program to set up an infrastructure funding account from which assistance is made available to public water systems. Loans made under the program can have interest rates between 0% and market rate and repayment terms of up to 20 years. Loan repayments to the state provide a continuing source of infrastructure financing. More information and program guidance, including grant allocations to each of the states is available through the Clean Water and Drinking Water State Revolving Funds Web site.	
Renewable Energy Production Incentive	Rebate	The Renewable Energy Production Incentive (REPI) Program was created by the Energy Policy Act of 1992 and reauthorized by the Energy Policy Act of 2005 to extend through 2026. REPI provides financial incentives for renewable energy electricity produced and sold by qualified renewable energy generation facilities, which include not-for-profit electrical cooperatives, public utilities, state governments, U.S. territories, the District of Columbia, and Indian tribal governments. The facilities are eligible for annual incentive payments of approximately 2 cents/kWh for: • Landfill Gas • Solar • Wind • Geothermal • Biomass • Livestock Methane • Ocean • Fuel cells using hydrogen derived from eligible biomass facilities To be eligible, qualified renewable energy facilities must be operational before October 1, 2016. Funding is subject to annual appropriation, and the program has historically been under-funded. During years in which there is a funding shortfall, legislation requires DOE to allocate 60% of REPI funds to solar, wind, ocean, geothermal, or closed-loop biomass technologies and the remainder to landfill gas, livestock methane, and open-loop biomass projects. If funds are not sufficient to make full payments to all qualifying facilities, payments are made to those facilities on a pro rata basis. To assist DOE in its budget planning, DOE requests that the owner or operator of a qualified renewable energy facility provide notification at least six months in advance of electricity generation. To receive payment, qualified facility owners and operators submit information, such as monthly electricity generation, to DOE during the first quarter (i.e., October 1 through December 31) of the next fiscal year. More information and details about the application procedures are provided on the REPI Web site and in the Partnership's funding database.	12/31/2026
Energy Efficiency and Conservation	Grant	The Energy Efficiency and Conservation Block Grant (EECBG) Program provides grants to local governments, tribal governments, states, and U.S.	

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<tr><td>Block Grant Program</td><td></td><td>territories to reduce energy use and fossil fuel emissions, and to implement energy efficiency improvements. Through formula and competitive grants, the Program empowers local communities to make strategic investments to meet the nation's long-term goals for energy independence and leadership on climate change.

The EECBG Program is intended to help U.S. cities, counties, states, territories, and Indian tribes to develop, promote, implement, and manage energy efficiency and conservation projects and programs designed to:
• Reduce fossil fuel emissions;
• Reduce the total energy use of the eligible entities;
• Improve energy efficiency in the transportation, building, and other appropriate sectors; and
• Create and retain jobs.

Funding for the EECBG Program under ARRA totals $3.2 billion. Of this amount, approximately $2.7 billion will be awarded through formula grants. In addition, approximately $454 million will be allocated through competitive grants.

All states are eligible to apply for direct formula grants and competitive grants from DOE. Depending on population, cities and counties are eligible for EECBG Program funds either directly from DOE or from the state in which they are located.

To date, DOE has awarded more than 1,200 EECBGs, totaling over $1.4 billion. The first EECBG formula grant awards were made on July 24, 2009, and continue to be made each week.

On October 19, 2009, DOE issued its competitive EECBG funding opportunity announcement. The announcement seeks innovative state and local government and Indian tribe programs, and will use up to $454 million in ARRA EECBG funds for these competitive grants awarded in the two topic areas described below. Applications were due to DOE by December 14, 2009, and the voluntary letters of intent were due by November 19, 2009.
• Topic 1: Retrofit Ramp-Up, $390 million. The first topic area will award funds for innovative programs that are structured to provide whole-neighborhood building energy retrofits. These will be projects that demonstrate a sustainable business model for providing cost-effective energy upgrades for a large percentage of the residential, commercial, and public buildings in a specific community. DOE expects to make 8 to 20 awards under this topic area, with award size ranging from $5-75 million. Eligible entities include states, formula-eligible local and tribal governments, entities eligible under Topic 2, and nonprofit organizations authorized by the preceding entities.
• Topic 2: General Innovation Fund, $64 million. The second topic area will award up to $64 million to help expand local energy efficiency efforts and reduce energy use in the commercial, residential, transportation, manufacturing, or industrial sectors. DOE expects to make 15 to 60 awards, with award size ranging from $1-5 million. Eligible entities include local and tribal governments that were not eligible to receive population-based formula grant allocations from DOE under the EECBG program; a governmental, quasi-</td><td></td></tr>
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		governmental, or non-governmental, nonprofit organization authorized by and on behalf of a unit of local government (or Indian tribe) that was not an eligible entity; or a consortia of units of local governments (or tribes) that were not eligible entities. For complete details on the availability of funds please visit the EECBG Web site, or the Partnership's funding database.	
State Energy Program	Grant	The State Energy Program (SEP) provides grants to states to address their energy priorities in the areas of energy efficiency and development of renewable energy technologies. The ARRA appropriated $3.1 billion for the program for fiscal year 2009. In order for a state to be eligible for these funds, it must commit to all three of the following: • Instituting policies at state-regulated utilities that support energy efficiency; • Adopting energy efficient building codes; and • Prioritizing grants toward funding energy efficiency and renewable energy programs. States will have discretion over how the money is distributed. Local governments and others interested in developing CHP projects should contact their State Energy Office to learn more about their state's process for distributing grants. DOE has posted the list of State Energy Offices. In Maine, SEP funds are directed to Efficiency Maine and starting July 1, 2010 will be directed to the Efficiency Maine Trust. The Weatherization and Intergovernmental Program in the DOE Office of Energy Efficiency and Renewable Energy manages SEP. More information about SEP can be viewed on the SEP Web site.	
Innovative Energy Efficiency, Renewable Energy, and Advanced Transmission and Distribution Loan Guarantees	Loan	The Energy Policy Act of 2005 authorized the U.S. Department of Energy to issue loan guarantees to eligible projects that avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases. The projects need to employ new or significantly improved technologies when compared to technologies in service in the United States at the time the guarantee is issued. Under the solicitation that closed in February 2009, the minimum application fee was $75,000, which indicates that the program has historically been designed to support larger scale renewable energy and bio-fuel projects. DOE periodically publishes requests for applications for loan guarantees, which can target specific technologies or be general. ARRA expanded the loan guarantee program with $6 billion for renewable energy systems, bio-fuel, and electric power transmission projects. "Renewable energy systems" include those that generate electricity or thermal energy (or manufacture component parts of such systems). Bio-fuel projects are limited to those that are likely to become commercial technologies and will produce transportation fuels that substantially reduce life-cycle greenhouse gas emissions compared to other transportation fuels. The 2009 funds are limited to projects that commence construction by September 30, 2011. More information about DOE's loan guarantee program, including solicitation announcements, is available on the program's Web site.	
Community Based Renewable	Loan	In response to legislative direction, the MPUC established a community-based renewable energy pilot program to encourage the sustainable development of community-based renewable energy in the State. The	

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Energy Pilot Program		program is not to exceed 50 megawatts (MW) in capacity and eligible projects must include qualifying owners, community support, grid-connection, and capacity not to exceed 10 MW. One of two incentives can be applied to projects, either long-term contracts or a set renewable energy credit multiplier set at 150% of the amount of the electricity. The State may give purchasing preference to electricity generated by community-based renewable projects, the MPUC can incorporate into the supply of the standard-offer service and shall arrange for a green power offer composed of green power supply and will incorporate green power supply from community-based renewable energy projects to the maximum extent possible.	