Development of Cost Benefit Information and Business Case for Integrated Community Energy Solutions

Final Report

Task 2
Technical Support for Integrated Community Energy Solutions

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Executive Summary

The Metropolitan Washington Council of Governments (COG) recently launched a new initiative in the region to advance district energy systems, combined heat & power (CHP), and microgrids. This report:

- Describes these clean energy technology options;
- Provides generalized costs and benefits, including capital and operating costs, power-related benefits, energy efficiency benefits and environment benefits;
- Summarizes challenges that can constrain the implementation of these systems; and
- Describes alternative models for ownership and operation of these systems.

District energy systems (DES) deliver hot water, steam or chilled water from a central plant(s) to multiple buildings via a network of pipes to meet thermal end uses: space heating, domestic hot water, air conditioning or industrial process heating or cooling. DE systems can use a wide variety of energy sources including CHP, and are typically a key infrastructure in Community Energy Systems (CES). The term CES is frequently used interchangeably with DES.

CHP systems use the same energy source to simultaneously produce useful thermal energy and electricity or mechanical power in an integrated system. A variety of technologies can be used for CHP, including reciprocating engines, combustion turbines and steam turbines.

Microgrids are small-scale electricity distribution systems that link and coordinate multiple distributed energy resources into a network serving some or all of the energy needs of one or more users located in close proximity, which can operate connected to the traditional centralized electric grid or autonomously from it, in an intentional island mode.

It cannot be overstressed that the generalized characterization of technologies (including efficiencies and costs) in this report should not be applied to specific cases without a case-specific evaluation of loads, densities, fuel and electricity costs and other case-specific circumstances.

The report presents generalized economics for 8 DES scenarios, with the following sources used for baseload heating and cooling capacity:

1. Natural gas chillers and electric centrifugal chillers
2. Reciprocating engine CHP and absorption chillers
3. Gas turbine CHP and absorption chillers
4. Combined cycle CHP and absorption chillers
5. Biomass boiler and absorption chillers
6. Ground source heat pumps
7. Waste heat recovery and electric chillers
8. Solar heating and electric chillers

Baseload heating capacity is sized to provide 50% of the peak heating load, which supplies 86% of the annual heating energy. Absorption chiller capacity is sized to use the heat output of CHP or the biomass boiler. All DES assumed medium-temperature hot water distribution, chilled water distribution and thermal energy storage that is used seasonally for chilled water storage and hot water storage.

District energy costs are then compared with building-scale systems using natural gas boilers and electric centrifugal chillers.

District energy systems lay the groundwork for flexible community energy solutions that recover and distribute community energy sources including power generation waste heat, other waste heat source and ground source energy. Based on this analysis, a range of community energy technologies have the potential to save energy, reduce GHG emissions, cut peak power demand and save money in the COG region.

The generalized economic analysis concludes that:

- District energy natural gas boilers, electric chillers and thermal storage (typically the initial step in developing a DES can provide cost advantages over conventional hydronic building technologies, especially if low-cost financing is available.
- CHP is not cost-competitive where electricity is inexpensive but can be cost-effective in areas with high power costs if the excess electricity not needed by the district energy plant can be sold to the grid, especially if low-cost capital is available.
- The assumption of a $25 per metric ton carbon dioxide equivalent value for GHG significantly improves the cost savings with CHP.
- Biomass is not cost-effective at the scale of DES modeled.
- Ground source heat pumps are potentially cost-effective if low-cost capital is available.
- Solar district heating is unlikely to be cost-effective.
- Waste heat recovery is potentially very cost-effective but truly requires a site-specific analysis.

The impact of DES varies depending on the particular scenario, but generally provides significant reductions in total fossil fuel consumption, greenhouse gases (GHG) and regulated pollutants. These calculations include both direct consumption by the district energy plant or the building system and indirect consumption in the power grid resulting from electricity purchased from the grid. GHG reductions range from minor (about 2%) for DES boilers and chillers to highly significant (from about 60% to over 165%) for CHP.

District energy provides significant reductions in peak grid power demand, generally in excess of 25% compared with conventional approaches. With CHP, the peak power demand reduction ranges from 160% to 260%, as the CHP facility, which is sized based on the heating load, makes a large net contribution to the grid during the summer.

Development of a DES can be a significant undertaking, requiring an interactive progress on a range of fronts, including: market assessment; stakeholder communication; technical design; economic analysis; air emissions permitting; securing the revenue stream with customer contracts; permitting; risk analysis; and financial structuring and analysis.

An incremental approach to development of a DES can be the key to successful implementation. By starting with an anchor load (or multiple anchors, depending on geography), small networks are generally easier to finance and implement, with the potential to grow out and ultimately be integrated into a broader system.

Ownership structures have a significant impact on the options available for funding and financing the development of the system. There are many different models of ownership and operation with no single preferred model; the ultimate structure should be tailored to the goals of the major stakeholders. Key considerations in the assessment of models should include:

- Access to a range of project financing sources, including state and federal grants, tax credits, subsidized financing tools and cost-effective market-based financing.
- Risk mitigation in construction and operation of the system that can address energy costs and price stability, as well as changing environmental parameters.
- Flexibility to accommodate future expansions of the district energy system while supporting development and sustainability agenda.

Introduction

Background

The Metropolitan Washington Council of Governments (COG) recently launched a new initiative in the region to advance district energy systems (DES), combined heat and power (CHP), and microgrids. These technologies are defined below. Deployment of these technologies in the region has the potential to:

- cut emissions of both criteria pollutants and greenhouse gases;
- reduce peak power demand;
- enhance energy security by providing local and more reliable sources of energy;
- reduce energy cost volatility; and
- strengthen the local economy by spending more energy dollars locally.

Definitions

Although there are no universally accepted definitions of the following interrelated and overlapping terms, the meaning of these terms as used in this report are as follows.

District Energy (DE) or District Energy Systems (DES)

District energy systems deliver hot water, steam or chilled water from a central plant(s) to multiple buildings via a network of pipes to meet thermal end uses: space heating, domestic hot water, air conditioning or industrial process heating or cooling. DE systems can use a wide variety of energy sources including CHP, and may incorporate a microgrid.

Combined heat and power (CHP)

CHP systems use the same energy source to simultaneously produce useful thermal energy and electricity or mechanical power in an integrated system. A variety of technologies can be used for CHP, including reciprocating engines, combustion turbines, steam turbines, organic rankine cycle turbines and fuel cells.

Microgrids

Microgrids are small-scale electricity distribution systems that link and coordinate multiple distributed energy resources into a network serving some or all of the energy needs of one or more users located in close proximity, which can operate connected to the traditional centralized electric grid or autonomously from it, in an intentional island mode.

Integrated Community Energy Solutions (ICES)

ICES is a general term for a cross-cutting set of community systems that emphasize synergy between multiple sectors, such as energy supply and distribution, housing and buildings, transportation, industry, water, wastewater and solid waste management. Integrated Energy Master Plans, Community Energy Plans and Community Energy Strategic Plans are variants on this terminology. ICES may include DE, CHP or microgrid systems.

Community Energy Systems (CES)

A CES is an integrated approach to supplying community energy requirements from renewable energy or high-efficiency sources. Generally, CES include DE and may or may not include CHP or microgrids. The term CES is frequently used interchangeably with DES.

Eco-District

Although there is no widely held definition of this term, which has only recently come into use, It generally understood to refer to urban area in which planning is aimed at integrating the objectives of sustainable development and reduction of the ecological footprint of the project.

Focus of This Report

Community energy is an enormous topic, covering many end-uses, technologies, levels of government and policy issues. This project does not address every strand of this complex web. The effort is focused on district energy, CHP and microgrids. Technologies such as electric vehicles, non-CHP renewable power generation (wind, photovoltaic, etc.) are not part of the scope of this project.

It cannot be overstressed that the generalized characterization of technologies (including efficiencies and costs) in this report should not be applied to specific cases without a case-specific evaluation of loads, densities, fuel and electricity costs and other case-specific circumstances.

Organization of This Report

The deliverable of this task is a report on the business case for various approaches available for Integrated Community Energy Solutions, with a primary focus on district energy, microgrids, and CHP. There are four major elements in this report:

- Overview of Clean Energy Technology Options -- Overview of key clean technology options, including a description, graphic illustrations, and example cases from the US and internationally.
- Costs and Benefits -- Generalized overview of the costs and benefit of the clean energy options, including: capital costs, operating costs and total costs; power-related benefits; energy efficiency benefits; and environment benefits.
- Implementation Challenges – Description of major challenges that can constrain the implementation of integrated community energy systems.
- Ownership and Operation Models – Description of the advantages and disadvantages of different community energy system ownership and operation models.

Overview of Clean Energy Technology Options

This section describes a range of technologies relevant to district energy systems (DES), combined heat and power (CHP) and microgrids.

District Energy Systems Overview

District energy systems produce hot water, steam and/or chilled water at a central plant for distribution through underground pipes to buildings connected to the system to provide space heating, air conditioning, domestic hot water and/or industrial process energy. Although steam has historically been common in the USA, hot water is generally the preferred heat transfer fluid in new heating systems.

There are three major elements in a DES:

- Plants – equipment to produce hot water and chilled water, located at one or more locations.
- Distribution -- buried pipes to distribute hot water and chilled water. There would be four pipes (hot water supply and return, and chilled water supply and return).
- Building connections – the interface between the distribution systems and the building heating and cooling systems.

Options for production of hot water and chilled water are addressed in the subsequent sections. In this overview section it is useful to address some key principles in selecting energy sources, including temperature parameters and the selection of resources for meeting "base load" (required most hours of the year) and "peaking load" (required only during the coldest heating days or warmest cooling days).

Baseload and Peaking Load

In designing district heating systems, diagrams such as Figure 1 are important tools. This "load duration curve" chart shows the numbers of annual hours when the total district heating load is at or above a given percentage of the peak load, and is based on detailed climate data.[1] This is a generalized load duration curve assuming a mix of commercial, institutional and residential consumers in the Washington DC climate; the curve for any specific system may be different. The district energy approach takes advantage of load diversity, i.e. the fact that not all individual customers have their peak demand at the same time. This allows the DES to reliably supply a group of customers with less total capacity than would be the case if each customer installed their own boilers and chillers.

With the load duration information we can make sound decisions about how much of which types of resources we want to deploy for a district energy system. In most locations higher levels of heating (or cooling) load occur for very few hours per year. Consequently, we tend to install the

[1] American Society of Heating, Refrigeration and Air-conditioning Engineers, ASHRAE Fundamentals.

most efficient capacity (which often has a relatively high capital cost) to meet the "base load", which in this diagram is shown at 50% or less of the peak load. It is notable that this base load (indicated in orange) comprises 86% of the annual energy based on the load duration curve for Washington DC.

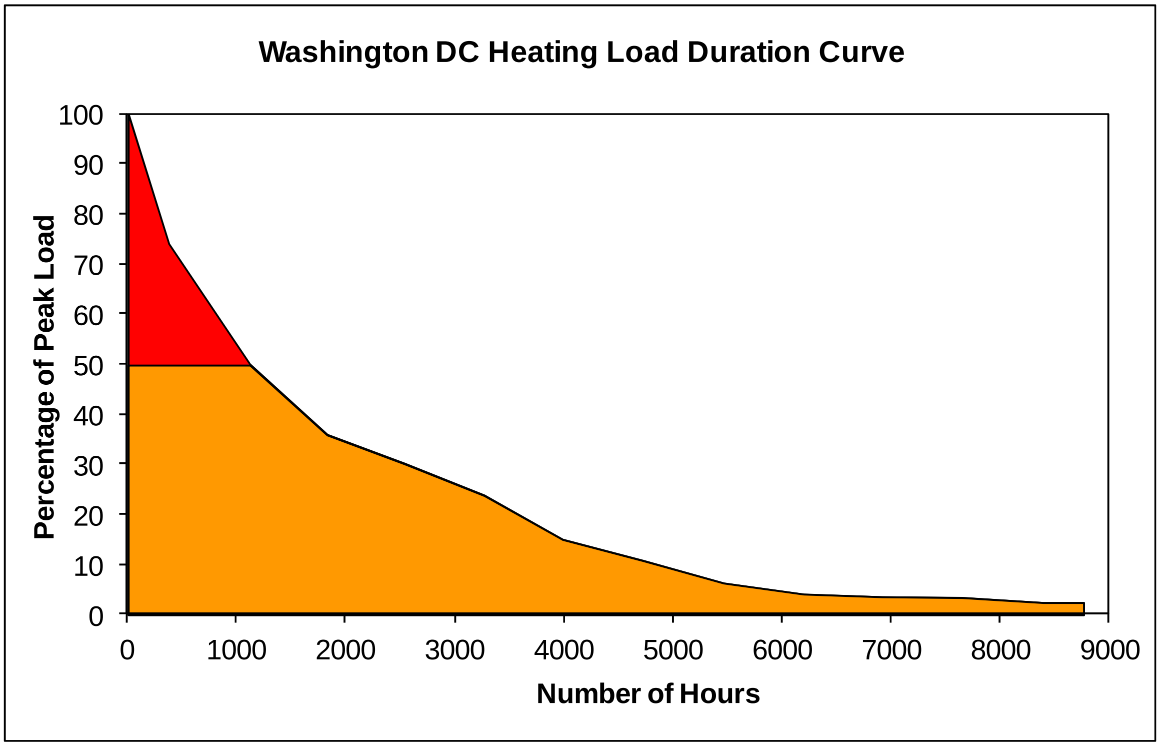

Figure 1. Generalized District Heating Load Duration Curve, Washington DC

Some technologies, such as CHP, become less efficient when operated at loads significantly below their design capacity. If only district heating is being supplied, the district heating requirements during warmer weather (May – September) are met with the same systems used for peaking and back-up (generally boilers fired with natural gas). For example, in Figure 2 the area shown in orange indicates the annual heating energy provided by gas engine CHP (69% of total energy), with the red areas showing when natural gas boilers would be used (31%).

However, if district cooling is produced using absorption chillers driven with CHP waste heat, during warmer weather the CHP can continue running, producing electricity to drive electric chillers and heat to drive absorption chillers.

A similar exercise occurs in selecting resources for district cooling, as illustrated in Figure 3. In this curve, the horizontal line shows the amount of peak cooling load that could be supplied with absorption chillers using waste heat from CHP. Although providing only 16% of the peak cooling capacity, CHP could supply 52% of the annual cooling energy. With summertime use of CHP heat, the CHP facility can be operated year-round.

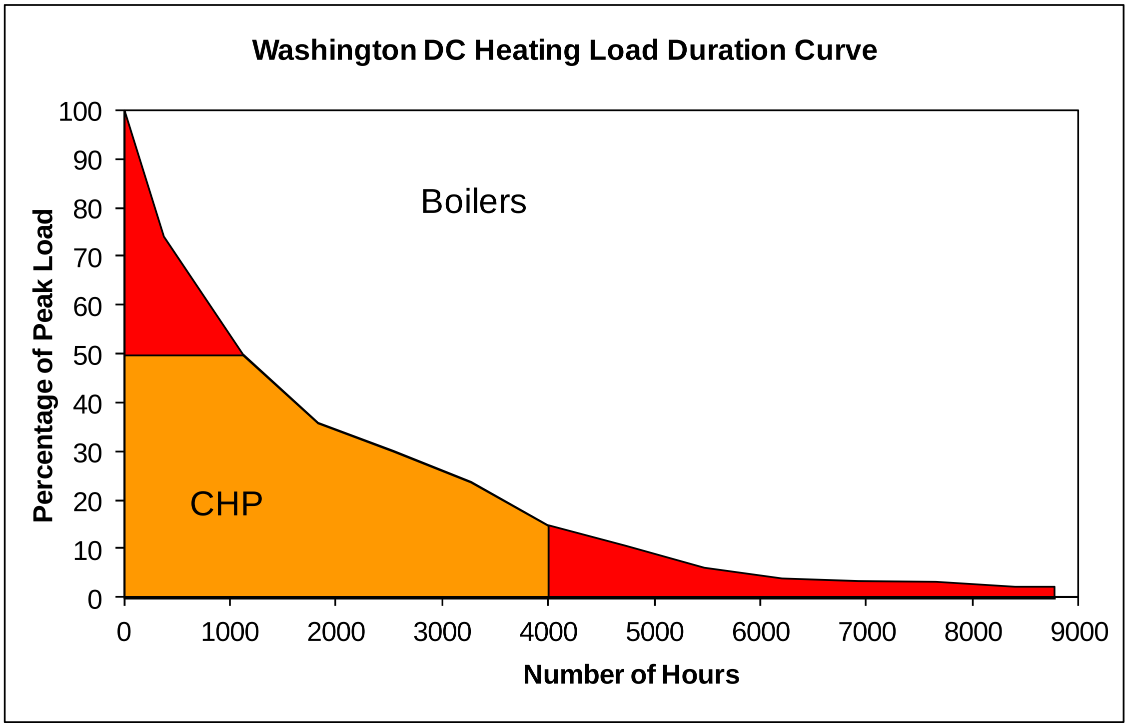

Figure 2. Heating Load Duration Curve for Washington DC Showing Gas Engine CHP for Baseload and Gas Boiler Operation for Peaking and Low Loads

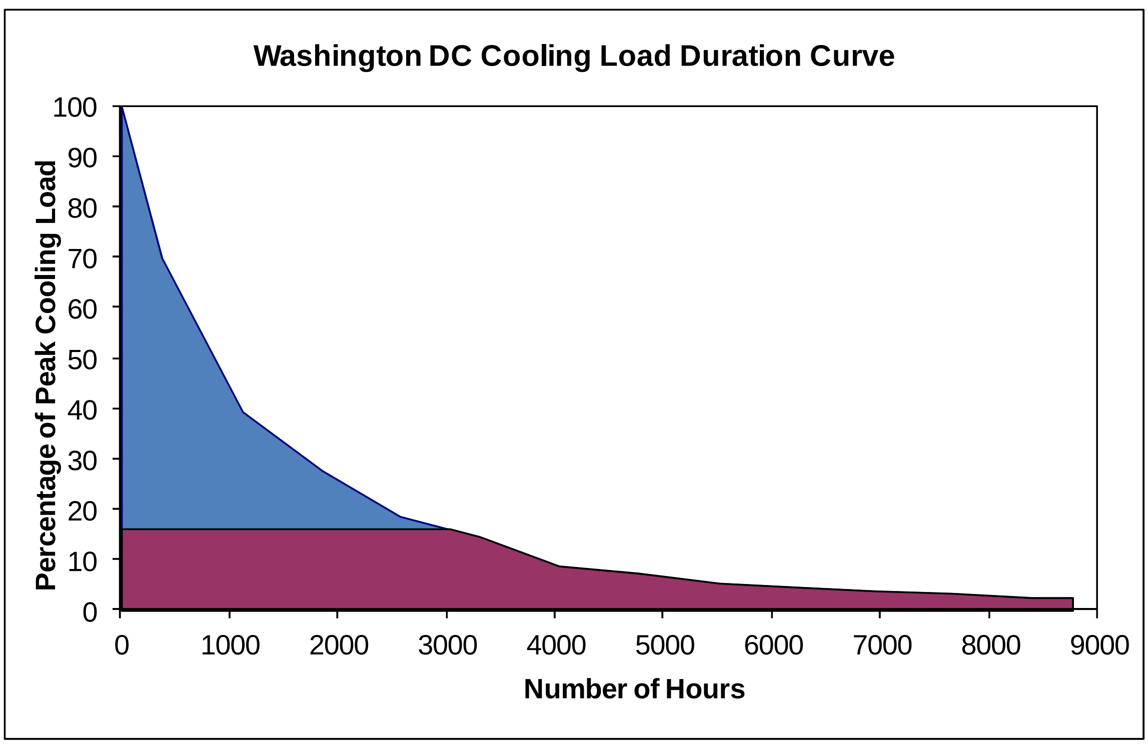

Figure 3. Cooling Load Duration Curve for Washington DC Showing CHP Heat-Driven Chillers for Baseload

Temperature Considerations

Selecting the supply and return temperatures for district heating and cooling is a critical design decision. In simple terms, operating district heating systems with a higher "Delta T" (temperature difference between supply and return water) can help reduce the size and thus capital cost of distribution pipes. By dropping the district heating temperatures, it is possible to pick up a range of waste heat sources, such as chiller condenser heat, reciprocating engine jacket water or industrial process waste heat. Representative temperatures for a range of potential heat sources are illustrated in Figure 4.

Designing district hot water systems for lower temperatures also opens up the potential to access not only waste heat but also renewable resources such as lower-cost solar thermal flat-plate solar collectors (which are less expensive compared with parabolic trough or other high-temperature solar technologies used for solar power generation).

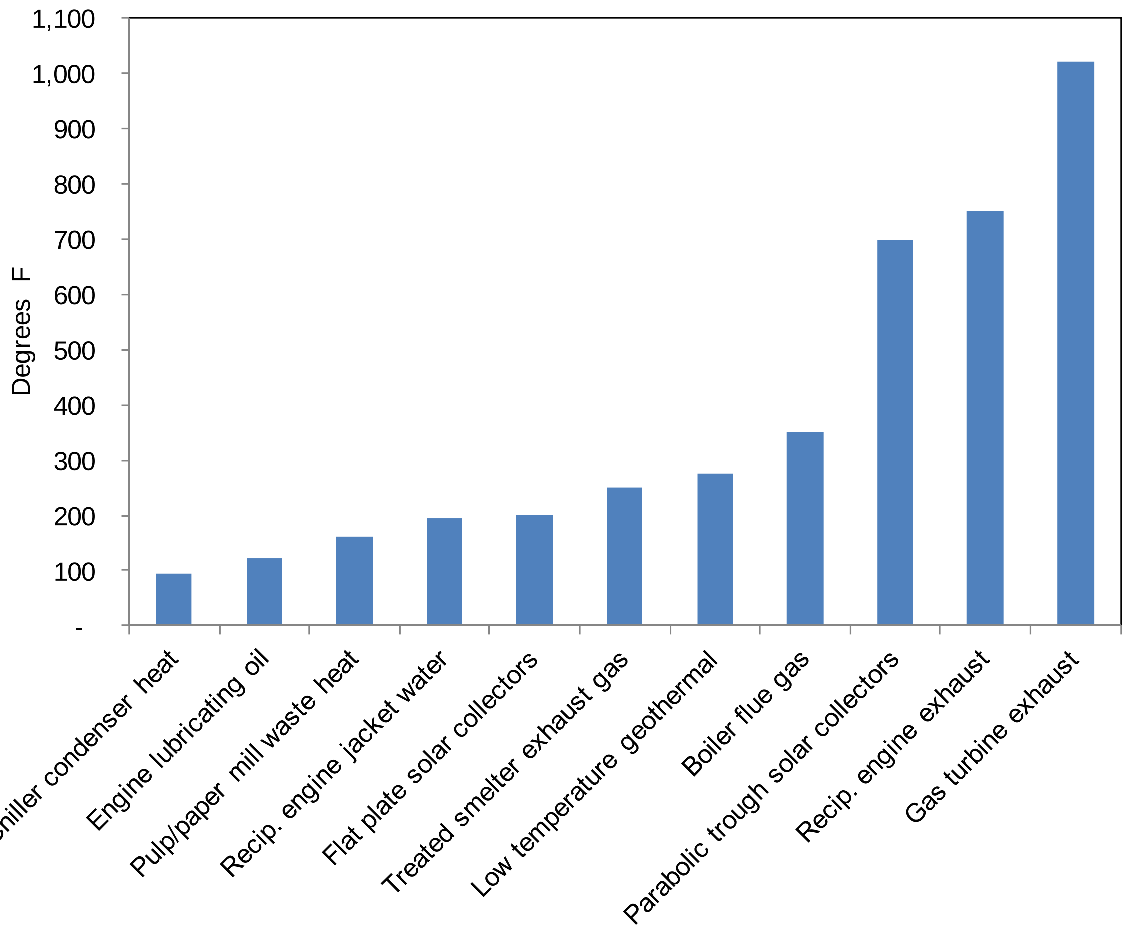

Figure 4. Temperatures of Potential Heat Sources [2]

[2] Spurr, M., Why Energy Policy Will Get You into Hot Water, International District Energy Association, District Energy Magazine, Fourth Quarter 2010.

The highest district heating temperatures and the lowest district cooling temperatures are only required during the coldest and hottest weather, respectively. For most of the year, the district system can be operated at lower hot water or higher chilled water temperatures than the peak design temperature. In the later analyses in Costs and Benefits chapter of this report, we assume:

- District heating supply/return temperatures of 250/160°F (on the coldest day);
- District cooling supply/return temperatures of 40/58°F on the hottest day;
- Base load heating resources are supplied at supply/return temperatures of 212/160°F;
- Base load cooling resources are supplied at supply/return temperatures of 44/58°F;
- For peak heating conditions, natural gas boilers are used to meet peak temperature and energy requirements.
- For peak cooling conditions, electric centrifugal chillers are used to meet peak temperature and energy requirements.

Distribution Systems

Hot water distribution systems are typically constructed of pre-insulated steel pipe surrounded by polyurethane insulation, with a polyethylene water vapor jacket applied over the insulation, as illustrated in Figure 5. These piping systems are designed for hot water service up to 250°F. The same type of pipe is generally used for district cooling applications also, but with less (or, in some cases, no) insulation. These distribution systems are generally installed with an integrated leak detection system that is built into the pre-fabricated pipe sections.

These piping systems can efficiently transmit heat over long distances. For example, the heat transmission pipe shown in Figure 6 moves industrial waste heat 14 miles to a district heating system in Sweden.

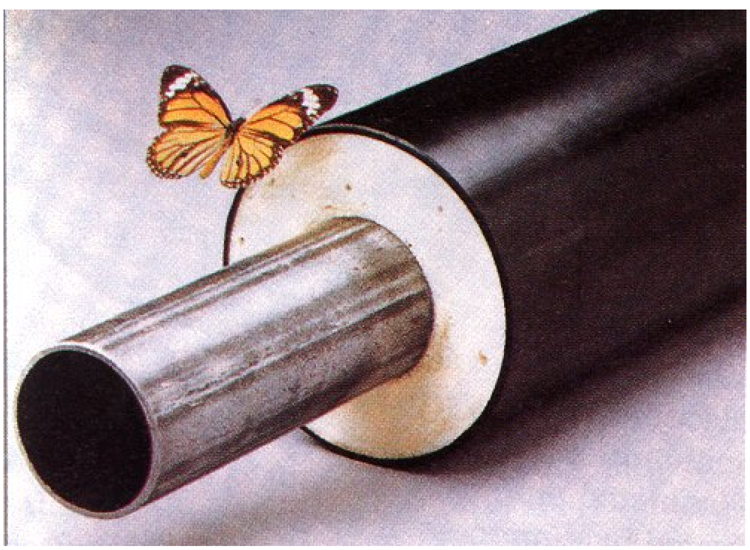

Figure 5. Pre-insulated Steel Pipe Typically Used in District Heating Systems

Figure 6. Long Distance Heat Transmission

Thermal losses and pumping energy in district heating piping systems will vary depending on length and size of pipes, flow, temperatures, soil condition and insulation. A recent study analyzed heat losses for three "intensities" of district heating systems, as summarized in Table 1.[3] In our analysis, we conservatively modeled "typical" district heating systems using the data from Table 1 for "medium density" systems.

[3] VTT Technical Research Centre of Finland, FVB Sverige ab, BRE Building Research Establishment Limited, BB Energiteknik (2011), District heating for energy efficient building areas, International Energy Agency Programme of Research, Development and Demonstration on District Heating and Cooling including the integration of CHP, Annex IX, 8-DHC-11-02.

District Heating System Density	Annual delivered energy (MMBtu/trench foot)	Annual distribution loss
Low density	3.1	12.4%
Medium density	8.5	4.7%
High density	15.6	1.9%

Table 1. District Heating System Distribution System Efficiencies

District cooling thermal losses are lower because there is less differential between the district system temperature and ambient temperatures. On the other hand, district cooling pumping energy is about 4 times higher than district heating per delivered kWh of thermal energy because more water is pumped per delivered unit of thermal energy.

Building Energy Transfer Stations

Energy is transferred from the district energy distribution system to the building heating or cooling system in one of two ways. In direct systems the district supply water is circulated directly through the customer's radiators or air-handling equipment. In indirect systems the distribution system and the building systems are isolated from each other, with heat exchangers used to transfer heat between the two systems. Figure 7 shows a typical heat exchanger, which is a very compact device.

Most district heating systems use indirect connections. In district cooling systems a direct connection is most common, but this can vary depending on the system supply pressures at the building location, the condition of the building equipment and the height of the building.

Figure 7. Heat Exchanger Used to Transfer Thermal Energy to Building System

Combined Heat and Power (CHP)

In electric-only power plants, most of the energy input to the plant ends up as waste heat. In simple cycle gas turbines all of the energy in the exhaust gases is wasted. Power plants using a steam turbine (either steam turbine or gas turbine combined cycle plants) condense the steam exiting from the turbine. This creates a vacuum on the exit end of the steam cycle, thus increasing the torque and power output of the steam turbine. However, most of the energy then ends up in the condenser cooling system (using cooling towers which put the heat into the air, or dissipating the heat in a body of water such as a river). Reciprocating engines lose heat through the exhaust gas, engine cooling jacket, lubricating oil and other systems.

With each of these power generation technologies adapted for CHP, much or all of the waste heat can be recovered for heating or for conversion to cooling using absorption chillers or steam turbine chillers.

Steam turbine power plants are the most common type of plant in the world today. Any type of fuel can be burned in a boiler to make steam, which drives a steam turbine which in turn spins a generator. The capital cost of steam turbine plants are higher than other alternatives, but the ability to burn lower-cost solid fuels (e.g., biomass) can make steam turbine plants cost-effective.

Gas turbines, often called combustion turbines, are basically like jet engines (in fact, many commercial systems are so-called “aero-derivatives,” i.e., they are directly evolved from aircraft engines). Natural gas is combusted, and the hot gases drive a turbine which in turn spins a generator. The exhaust gas coming out of the turbine is very hot (850-1000°F), and can be directed to a heat recovery boiler to generate steam or hot water for thermal purposes or for generation of additional electricity. A "combined cycle" gas turbine system uses the steam generated by the heat recovery boiler to turn a steam turbine-generator. In a combined cycle plant, the heat recoverable for district energy thermal uses is in the heat exhausted from the steam turbine that would otherwise be dissipated in the cooling towers.

In gas engine CHP, a generator is attached to the shaft of an internal combustion engine (like a truck engine). Heat is recovered when the hot exhaust gas is cooled in a heat recovery boiler. Heat can also be recovered from the engine cooling water and oil lubrication system. In addition, heat can be recovered from other devices (turbocharger and intercooler). Both gaseous and liquid fuels can be used in reciprocating engines.

The efficiency of a given CHP facility depends on many case-specific factors, including equipment characteristics, temperature of recovered thermal energy, ambient temperature conditions and part-load operation. Table 2 summarizes the efficiency assumptions for the analysis for a range of CHP technology types and sizes. These assumptions are representative for the technology, assuming:

- District heating temperature conditions presented earlier in this section;
- Ambient temperature conditions of 60°F;
- Operation at 30% of capacity or above.

Organic rankine cycle (ORC) is a technology for generating power that is similar to a steam turbine except that the working fluid is a volatile organic fluid, such as isopentane, rather than steam. The advantage is that these fluids can be used at temperature below 750°F, so a variety of waste heat sources can be used. ORC is also frequently used in very small biomass-fired CHP systems.

		Efficiency (Higher Heating Value)		
CHP Technology	**Size (MWe)**	**Power**	**Heat**	**Total**
Gas engine CHP	3	36%	40%	76%
Simple cycle gas turbine	10	29%	46%	75%
Combined cycle gas turbine	20	40%	35%	75%
Steam turbine	30	22%	56%	78%
Organic rankine cycle	1.5	15%	67%	83%

Table 2. Combined Heat and Power Efficiency Assumptions [4]

[4] Energy and Environmental Analysis (2008), CHP Technology Characterization, prepared for the U.S. Environmental Protection Agency, and Spurr, M. and Larsson, I. (1996), Integrating District Cooling with Combined Heat and Power, International Energy Agency Programme of Research, Development and Demonstration on District Heating and Cooling including the integration of CHP, Report 1996:N1, ISBN 90-72130-87-1.

Biomass

Biomass is any organic material, and can include urban waste wood (tree trimmings, unusable pallets, etc.), forest industry mill residues, forest harvesting residues, agricultural residues, and organic portions of municipal solid waste or energy crops. As distinguished from biogas, which is produced through gasification of this material, the term "biomass" refers to direct combustion of these organic materials. Figure 8 shows the harvesting of woody biomass which is otherwise unusable after logging.

Figure 8. Harvesting of Woody Biomass

Increasing interest in biomass is driven by advances in technology, environmental benefits, energy supply and price stability, and the potential for significant spin-off employment in fuel procurement and processing. Using biomass for energy also can eliminate a disposal problem and create income. Residues from wood processors can be diverted from landfills or incineration.

Biomass is generally considered GHG neutral. Biomass emits the GHG carbon dioxide (and sometimes methane, a very powerful GHG) when it decays or is combusted. However, during its growth, living biomass absorbs CO_2 from the atmosphere by photosynthesis, so the net GHG effect of the biomass is neutral. By using biomass, GHG emissions from fossil fuel are eliminated.

Figure 9 show a 25 MW CHP plant operated by District Energy St. Paul. This facility has used urban waste wood to provide electricity, hot water and chilled water for downtown St. Paul since 2003.

Figure 9. Biomass CHP Plant in Downtown St. Paul, Minnesota

Biogas

Biogas is a renewable fuel produced from organic matter such as sewage sludge, organic solid waste, animal manure, crop residue or other organic materials. Biogas is formed through a process known as anaerobic digestion, where bacteria degrade biological material in the absence of oxygen and release methane. Anaerobic digestion is carried out in a number of steps and can use almost any organic material as a substrate.

Biogas may be produced intentionally or as a by-product of other processes (e.g., methane produce in a landfill). In the latter case, the harvesting of biogas is an important role in waste management because methane is a huge contributor in global warming, far greater a larger threat than carbon dioxide. Figure 10 shows a biogas production facility in Linköping, Sweden. In this case, the biogas is used to fuel buses and cars.

Biogas can be consumed as is, or can be upgraded (by removing carbon dioxide, trace contaminants, and any hydrogen sulphide) to “pipeline quality”. If the impurities in biogas are removed, it is considered renewable natural gas or bio-methane and can be distributed to customers via the natural gas grid.

Figure 10. Biogas Production Facility in Linköping, Sweden

Solar Thermal

Relatively low-cost solar technology -- flat-plate collectors – can be used to harvest solar energy for district heating. Figure 11 shows the solar installation in Marstal, Denmark, which provides more than 30% of total annual district heating requirements. Denmark currently has more than 200,000 square feet of solar collectors installed in conjunction with district heating systems. In the U.S.A., District Energy St. Paul has begun operation of a 3.7 MMBtu/hour solar thermal system integrated with a hot water district heating system, incorporating 21,000 square feet of high-performance solar collectors manufactured in Denmark.

Figure 11. Solar Thermal Array for District Heating in Marstal, Denmark

Heat Pumps

Heat Pumps Generally

Heat pumps are devices that move heat from air or water at a lower temperature to air or water at a higher temperature. Heat pumps effectively reverse the natural process of heat flowing from a higher temperature source (air or water) to a lower temperature sink (air or water). Typically, this is accomplished with a mechanical device such as a compressor, usually powered with electricity.

There are a variety of types of heat pumps. When an air-to-air heat pump is used for heating, it is like an air conditioner working in reverse:

- The heat source is outdoor air, with a temperature lower than the desired indoor air; and
- The heat is increased in temperature and released to the indoor air.

Heat pumps can be designed to provide heating only; heating or cooling, as required; or heating and cooling simultaneously.

Heat pumps can use a variety of water sources as the heat sink (cooling) or heat source (heating), for example surface water (sea water or lake water) or sewage effluent. Significant implementation of heat pumps using seawater, lake water or sewage effluent occurred in Sweden in the 1980s with the availability of surplus electricity capacity from nuclear plants. During this period a number of large heat pumps, some units up to 190 MMBtu/hour, were installed. In the 1990's some of the heat pumps were adapted to simultaneously supply district heating from the heat pump condenser and district cooling from the heat pump evaporator for those times of the year (spring, fall and winter) when both heating and cooling are required.

Ground Source Heat Pump

Heat pump systems can tap the relatively consistent temperature of the ground for heating and cooling. For example, water can be pumped from a well, circulated through the heat pump for heating and injected (after being cooled through the heat pumps) into a second well. The second well can then be used as a source of chilled water for a reversed process, in which the heat pump is used to provide air conditioning. Alternatively, water can be circulated through the ground in vertical boreholes or horizontal trenches to heat or cool it.

The efficiency of heat pumps is measured in Coefficient of Performance (COP), which is the ratio of heat (or cooling) output to electric energy input. Heat pump efficiency depends on many case-specific variables. However, for the assumed low-temperature hot water district heating system on which the Costs and Benefits analysis is based, a representative annual COP value for ground source heat pumps in heating applications is 3.2 and for cooling 4.2.

Waste Heat

There are sources of surplus heat from industrial, municipal and commercial processes that are sufficient for heating buildings. For example, Gothenburg Sweden derives only 4% of the heat for its district heating system from fossil fuels. 30% comes from industrial waste heat from refineries and other industries, 27% is from municipal waste, 19% from CHP, 5% from wastewater heat pumps and 15% from biomass and other renewable sources. (See Figure 12.)

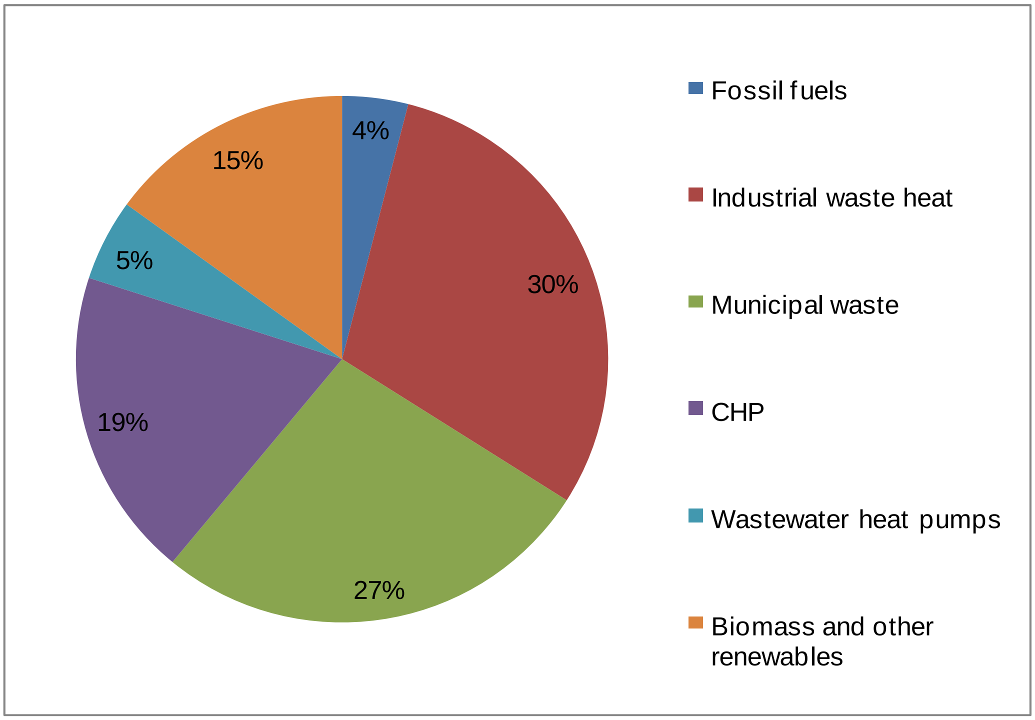

Figure 12. Energy Sources for District Heating in Gothenburg, Sweden[5]

The Gothenburg district heating system buys industrial waste heat from two oil refineries as well as from smaller industries. This district heating system also collects heat from treated municipal wastewater.

In North America, a highly efficient hot water district heating system was installed as part of the revitalization of the Southeast False Creek area in Vancouver. The site is former industrial land and the location of the Athlete's Village for the 2010 Winter Olympics. The system consists of a low temperature hot water district heating system and electric heat pumps to extract heat from

[5] Göteborg Energi (2009), Göteborg Energi's District Energy System", Application for Global District Energy Climate Awards.

sewage. Construction began in 2007 and the system was commissioned prior to the 2010 Winter Olympics. The DES is expected to continue expanding to serve additional mixed-use real estate development.

There is another source of “waste heat” that can be harvested to feed a hot water district heating system: the heat extracted from building space or servers that is normally exhausted to the atmosphere through cooling towers. Heat pumps can be used to extract this heat and “pump” the temperature up with electricity to 170°F. This temperature is sufficient for part of the year in a new low temperature hot water district heating system, with the temperature boosted for a relatively few peak hours per year using a boiler. Stanford University is now planning to replace its steam system with hot water as part of a long-term plan to integrate the heating system with the district cooling system, recovering rejected chiller heat for a low-temperature district heating system.

Data servers are a particularly promising source of waste heat. A square foot of data center can produce over 70 Btu per hour of heat, enough to provide baseload heating for 5 square feet of office space.[6]

Gas Boilers

Boilers, usually fuelled with natural gas, are used to provide additional heat during peak demand periods and during low-load periods when the baseload heat resource, such as CHP, may not be able to run as efficiently. In addition, gas boilers provide back-up capacity for times when the baseload production facilities are undergoing maintenance.

Natural gas boilers are often the first step in developing a district heating system. Relatively inexpensive, these boilers may provide all heating requirements in the early stages of system growth. As the load grows, it becomes economically feasible to install more sustainable technologies (which usually have a higher capital cost but lower operating costs), such as CHP, biomass or waste heat recovery.

New gas-fired boilers can achieve efficiencies of 80-85% on a Higher Heating Value (HHV) basis, although lower efficiencies on a seasonal average basis can result if the boiler is operated at widely varying loads. (HHV includes the latent heat of vaporization of water vapor in the combustion gases.) Condensing boilers, which recover the latent heat of vaporization, can achieve efficiencies over 90% under optimum conditions.

Electric Chillers

Electric chillers use a motor to compress refrigerant vapor, which then condenses to a higher pressure and consequently releases heat. This “condenser heat” is then released, generally to the air through a device called a cooling tower. The refrigerant condensate is expanded through a valve to a lower pressure; as it expands it picks up heat from the space being air conditioned, thereby evaporating and returning to its original condition to begin the cycle anew.

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[6] FVB client analysis, Nov. 11, 2011 (confidential).

New district energy plant electric centrifugal chiller systems operated at a good load factor have a total annual system COP of 4.4, including power to drive the compressor as well as auxiliaries such as cooling tower, condenser pump and chiller pump. In a district cooling system it is typically easier to operate chillers at optimal load factors to achieve high efficiencies.

Absorption Chillers

The absorption cycle uses heat to generate cooling, using two media: a refrigerant and an absorbent. Water/lithium bromide and ammonia/water are the most common refrigerant/absorbent media pairs, but other pairs can be used. In the absorption cycle, the refrigerant "flashes" from a liquid to a vapor in a device called an evaporator because the pressure in the evaporator is very low. In the process of evaporating, the refrigerant absorbs heat from the district cooling water. The vaporized refrigerant has a chemical affinity for the absorbent, so it is drawn to be absorbed by the absorbent and in the process becoming a liquid again, intermixed with the absorbent. Heat is an essential part of this process, because it boils the refrigerant/absorbent mix and separates these two fluids to begin the process again.

A typical absorption chiller system has a heat COP of 0.60 (1.0 kW of heat input to each 0.60 kW of cooling output) and an electrical COP of 14.1 (1.0 kW of power to run auxiliaries per 14.1 kW of cooling produced).

Natural Air Conditioning

Water bodies can be used as "heat sink" for the heat extracted from buildings through a district cooling system. Where the water is cold enough, it can be used to meet the entire air conditioning requirement. Somewhat warmer surface waters are still useful as a heat sink from the cooling towers used to dissipate heat extracted from chillers.

Natural air conditioning most frequently uses cold water drawn from deep sources such as lakes or oceans to provide cooling to buildings. There are a number of district cooling systems utilizing deep water cooling throughout the world, particularly in Sweden. There are at least 7 deep water cooling systems in Sweden. Examples include:

- Stockholm, where the Baltic Sea is used in combination with heat pumps to supply over 85,000 tons of cooling for downtown Stockholm.
- Södertälje, with a 17,000 ton district cooling system at Lake Mälaren supplying a pharmaceutical plant and other commercial customers. Figure 13 shows the installation of polyethylene pipe in Lake Mälaren.
- Sollentuna, a 1,100 ton district cooling system that includes aquifer storage. During the winter, cold sea water from a bay of the Baltic Sea is stored in the aquifer to reduce the warmer temperature of the sea water during summer. (See Figure 14.)

In North America, natural air conditioning is used to cool the Cornell University campus and downtown Toronto. The Toronto system also uses a fresh water source, and is designed to use part or all of the water drawn from the water source as potable water after the cooling energy has been extracted from it. Generally, however, these systems return all of the water back to the source after cooling energy is extracted. Water is returned to the water source at shallow depths where the water is warmer to lessen or eliminate the impact of warm water rejection on the local ecosystem. A seawater district cooling system is also being developed for Honolulu.

Typically, a separate, closed chilled water distribution loop, which is isolated from the open water source loop, carries chilled water to buildings for cooling use. Often, the temperature of the chilled water supply in this closed loop is reduced further with electric chillers at times of peak cooling use.

The efficiency of a given natural air conditioning system depends on case-specific factors. Based on experience from the Stockholm, Toronto and Cornell systems, a representative COP for such systems is 24, i.e. for every 1 kW of electricity used, 24 kW of cooling is produced.

Figure 13. Installation of Polyethylene Pipe for Deep Water Cooling from Lake Mälaren, Sweden

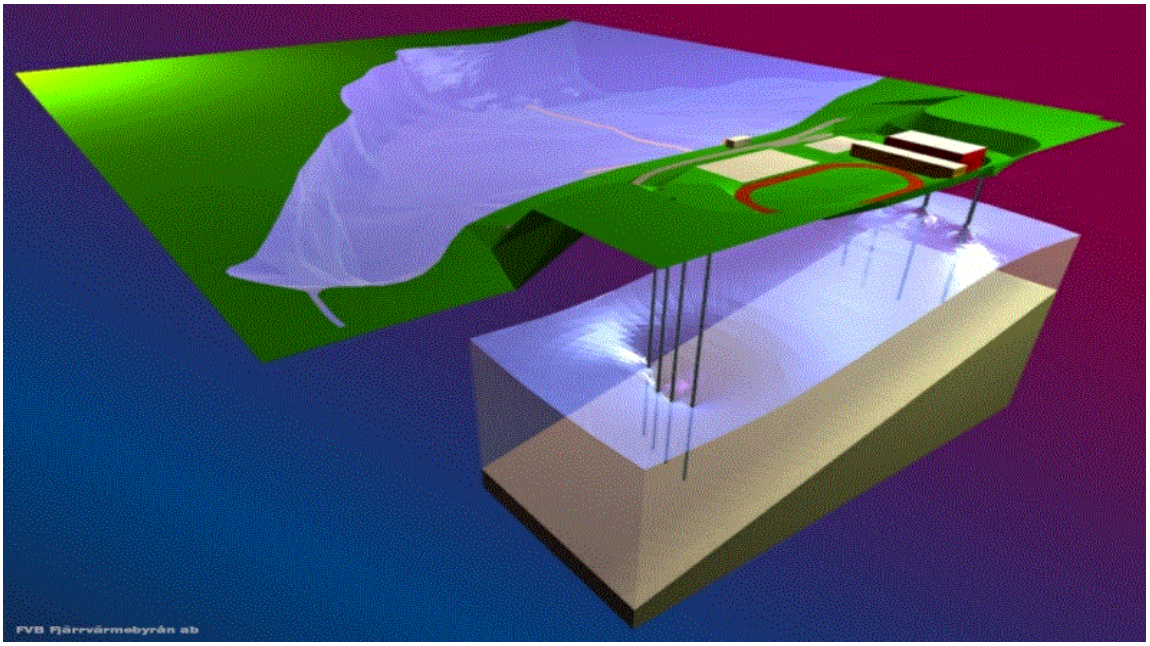

Figure 14. Illustration of the Aquifer Storage System Used for Seasonal Storage of Cooling Energy in Sollentuna, Sweden

Thermal Storage

Thermal storage can be an important strategy for reducing peak power demand, and optimizing the integration of CHP or waste heat recovery with district heating or district cooling. Hot water storage is commonly used in European district heating systems, facilitating a maximum production of hot water from renewable or waste heat sources when those sources are available, then using this stored energy when required, thereby maximizing use of sustainable energy sources. Figure 15 shows a hot water thermal storage tank, usually called an accumulator.

Figure 15. Hot Water Accumulator

In the U.S., thermal storage is generally limited to cooling systems based on energy price factors. Thermal storage systems are designed to be recharged on a cyclical basis (usually daily) and fulfill one or more of the following purposes:

- **Increase system capacity**. Demand for heating, cooling, or power is seldom constant over time, and the excess generation available during low demand periods can be used to charge the energy storage system in order to increase capacity during high demand periods. For example, cooling storage allows a district cooling system to install less chiller capacity and to use the installed capacity at a higher load factor.

- **Enable dispatch of CHP plants**. CHP plants are generally operated to meet the demands of the connected thermal load, which often results in excess electric generation during periods of low electric use. By incorporating thermal energy storage, the plant need not be operated continuously and can be dispatched within some limits.

- **Shift energy purchases to low demand/low cost periods**. Cooling storage allows a district cooling system to shift electricity demand from costly daytime on-peak periods to lower-cost nighttime periods.

- **Increase system reliability**. Thermal storage increases the flexibility and reliability of district cooling by ensuring that there is a readily available source of cooling which can be supplied to users with only a minimal requirement for pumping energy.

Cool storage can be provided through storage of chilled water or ice. Chilled water is the most common form of cool storage, using concrete or steel tanks to store chilled water generated with any type of conventional chiller. Chilled water is typically stored between 40°F to 44°F in one large or several tanks located above ground or below ground.

Where space is available for chilled water storage, the economies of scale for this technology can provide significant economic advantages over ice storage. Under normal conditions a chilled water storage tank is always filled with water. During discharge, cold water is pumped from the bottom of the tank and warm return water is supplied in the top. Due to the different densities for water at different temperatures a stable stratification can be obtained.

Ice generation and storage is a well-developed technology, and allows storage in a more compact space -- often a key issue in urban environments. The volume required for ice storage is 15 to 25 percent of the space required by chilled water storage for the same energy storage capacity. Ice storage also provides an opportunity to reduce the temperature of cooling distribution and therefore reduce distribution system and building system capital costs. These advantages must be weighed against higher capital and operating costs for ice-making equipment compared to water chillers. The average capital costs of ice storage are about twice those of chilled water storage, and the energy requirements are higher by about one third.[7]

Retrofit of Existing District Energy Systems

This report is focused on the characteristics, costs and benefits of new district energy systems. We have been asked to comment on retrofit of existing district energy systems. It is difficult to make useful generalizations about retrofit because there is such a huge variety of existing systems, each with its own specific characteristics, and a tremendous range of potential retrofit strategies.

Major categories of retrofit strategies include but are not are limited to:

- Implementation of CHP;
- Implementation of biomass or other renewable energy strategies;
- Implementation of thermal energy storage; or
- Partial or full replacement of steam distribution with more efficient hot water systems.

Implementation of CHP is a common retrofit strategy for a DES, facilitating improvement of energy efficiency and reductions in peak power demand, GHG emissions and net operating costs. CHP is often undertaken in conjunction with a system expansion. For example, in 2011 Thermal Energy Corp. (TECO) completed an extensive system expansion including a new 48 MegaWatts MW[8] CHP unit as well as 32,000 tons of new chiller capacity, an 8.8 million-gallon stratified

[7] ASHRAE Transactions 1995, V. 101, Pt. 2, "ASHRAE RP-766: Study of Operational Experience with Thermal Energy Storage Systems," as noted in "Energy and Economic Implications of Combining District Cooling and Thermal Storage," Andrepont, Kooy and Winters, 10th Annual Cooling Conference, International District Energy Association, October 1995.

[8] In the balance of this report, the abbreviations MW and MWh will generally be used to indicate MegaWatts electric and MegaWatt-hours electricity, respectively. For the most part, we use million Btu/hour (MMBtu/hr) and million Btu (MMBtu), respectively, to refer to thermal capacity or thermal energy. Some case study information refers to

thermal energy storage tank, additional distribution piping, and a new operations support facility featuring a state-of-the-art control room. This $377 million expansion is phase one of TECO's Master Plan Implementation Project to meet the growing cooling and heating needs of the rapidly expanding Texas Medical Center, the world's largest medical complex. TECO now has 120,000 tons of cooling capacity.[9]

The history of District Energy St. Paul (DESP) involves multiple steps in retrofitting of a legacy system. In the early 1980s a modern hot water district heating system was developed to replace a steam district heating system dating back to the early years of the 20th century. In the early 1990s a district cooling system was added, providing an additional energy service to customers. Chilled water thermal energy storage was subsequently incorporated into the system. As noted above, in 2003 the company began operating a biomass CHP facility producing 25 MW_e and 222 million Btu/hour (MMBtu/hr). Power is sold to the local electricity utility under a 20 year agreement. The CHP facility provides over 70% of the annual heat production. The biomass facility consumes urban waste wood.

In some cases biomass energy is added to a district energy system to produce only heat, as is the case with the Seattle Steam Company (SSC), which has operated a steam district heating system in downtown Seattle since 1893. SSC desired to incorporate biomass as a major source of heat because it is a renewable energy resource and would reduce GHG emissions. In addition, SSC wanted to reduce the quantity of wood sent to landfills and, by buying fuel from local sources, keep money spent on energy in the community. Unable to secure an adequate Power Purchase Agreement for the electricity output from a CHP plant, SSC opted to install a fluidized bed biomass heat-only boiler. The boiler's steam generation capacity is 80,000 lb/hr. (about 80 MMBtu/hr), or about 25% of the system peak demand. The urban waste wood fuel is a mix of pallets and crate materials, wood recovered from land clearing, and sawdust and wood trimmings from cabinet shops and sawmills. The capital cost of the biomass system was approximately $30 million, including air pollution control, fuel processing, transportation, storage and modification of an existing fuel handling and storage facility.

Most North American district heating systems are steam systems, and these systems serve their users and the environment well. However, as these systems expand and renew themselves in a carbon-constrained policy environment, we will see a trend of incremental moves to hot water for new service areas and in some cases comprehensive transitions to hot water distribution. Replacement of entire distribution systems is costly, but some district energy systems have concluded it is both cost-effective and a key to carbon reduction. For example:

- As noted above, District Energy St. Paul accomplished this nearly 30 years ago, replacing an old steam system with a Swedish design for hot water, at a capital cost of $46 million in 1982 dollars. To conserve energy, the system was designed to "reset" the hot water temperature from 250°F under peak winter conditions to 190°F during the summer.

MegaWatt thermal (MWt_h) or MegaWatt-hours thermal MWh_{th}), the units used commonly in Europe and elsewhere. One MWh thermal equals 3.413 MMBtu.

[9] http://www.districtenergy.org/case-studies

- In conjunction with implementation of CHP, in 2005 the University of Rochester replaced a major portion of their steam distribution system with a hot water system with a supply temperature under 200°F. The construction cost of the new hot water distribution system was $7.6 million to provide hot water service to about 3.9 million square feet of building space.

- Stanford University is now planning to replace their steam system with hot water as part of a long-term plan to integrate the heating system with the district cooling system, recovering rejected chiller heat for a low-temperature district heating system. Operating temperatures, design parameter and costs are still under study.

Microgrids

Microgrids are small-scale electricity distribution networks that link distributed power generation facilities to one or more users located in close proximity. A recent study[10] found that most microgrids are 10 MW or less, although some are as big as 40 MW.

New technologies are making it possible to create microgrids that effectively operate either independently ("islanded") or in conjunction with a broader power grid ("macrogrid"). Islanding would typically occur if a disruptive event arises in the macrogrid, such as short circuits, voltage fluctuations or service interruptions. This provides microgrid customers with levels of power quality and reliability that are usually better than with the local utility.

There are a range of potential economic benefits of microgrids. In addition to the potential energy savings from CHP or other distributed generation, costs related to purchase of electricity transmission and distribution (T&D) services may be reduced. Further, with power generation close to the loads, T&D losses can be reduced. Microgrids have the potential to capture economic value by participating in power demand response markets, and by offering enhanced power quality and reliability. Further, they may enable the local power utility to defer T&D capacity investments.

There are a variety of ownership and operational models for implementing microgrids. Companies such as Pareto Energy design, own and operate microgrids systems which include power generation facilities as well as electrical distribution infrastructure. The reported capital cost of their microgrid system is approximately $3 million per MW.[11] Pareto is now developing a microgrid for Howard University, easing pressure on the stressed Pepco substation serving the University.

An alternative approach is planned by San Diego Gas and Electric Company (SDGEC) in a "Beach Cities" demonstration project in Borrego Springs, CA. In this project, the microgrid system will be

[10] "Microgrids: An Assessment of the Value, Opportunities and Barriers to Deployment in New York State," Center for Energy, Marine Transportation and Public Policy at Columbia University, for the New York State Energy Research and Development Authority, Sept. 2010.

[11] "Power Play," Washington Business Journal, Sept. 24-30, 2010.

"unbundled," i.e. the distribution system will be owned by SDGEC but the generation facilities will be owned by customers or a third party.

Some universities, such as Cornell, operate their own microgrids, i.e. they own and operate the campus electrical distribution system, which is fed by both on-campus generation as well as utility power.

The cost of securing back-up capacity for microgrids is a critical cost hurdle for such systems. Installation of sufficient capacity within the microgrid to provide adequate back up is usually cost-prohibitive. Negotiation of acceptable terms for back up from the local electric utility is generally a challenge, because microgrids may be viewed by the local utility as a competitive threat rather than a benefit.

Microturbines

MIcroturbines are small gas- or liquid fuel-fired turbine-generators, usually under 500 kW of electricity output (although some 1 MW "microtubines" are now being marketed). Microturbines can operate as CHP unit, but unless they are integrated into a district energy system the number of annual hours they can operate in CHP mode are limited to times when there is a match between the building power and heat demands.

Generalized economics for a 200 kW microturbine operated as a CHP unit are summarized in Table 3. This analysis reflects the capital cost range claimed by a microturbine manufacturer ($2,500-5,000 per kW), although in a recent installation of a 200 kW microturbine for Philadelphia Gas Works cost $1.2 million, or $6,000 per kW).[12]

[12] http://articles.philly.com/2011-10-16/business/30286400_1_natural-gas-microturbines-heat-and-power/1

	Low	High	Average
Technical and economic parameters			
Capital cost ($/kW)	$ 2,500	$ 5,000	$ 3,750
Capacity (kW)	200	200	200
Heat rate (Btu/kWh)	13,500	13,500	13,500
Electric efficiency	25.3%	25.3%	25.3%
Heat recovery efficiency	44.7%	44.7%	44.7%
Total efficiency	70.0%	70.0%	70.0%
Maintenance ($/MWh)	$ 15.00	$ 15.00	$ 15.00
EFLH	3,000	3,000	3,000
Fuel cost ($/MMBtu)	$ 11.00	$ 11.00	$ 11.00
Capital recovery factor	0.1191	0.1191	0.1191
Annual operations			
Power generation (MWH)	600	600	600
Fuel consumed (MMBtu)	8,100	8,100	8,100
Heat produced (MMBtu)	3,622	3,622	3,622
Annual costs			
Capital recovery	$ 59,534	$ 119,067	$ 89,300
Natural gas	$ 89,100	$ 89,100	$ 89,100
Maintenance and supplies	$ 9,000	$ 9,000	$ 9,000
Total	$ 157,634	$ 217,167	$ 187,400
Offset cost of heat *	$ 49,805	$ 49,805	$ 49,805
Net cost of electricity	$ 107,828	$ 167,362	$ 137,595
Unit cost			
Net unit cost of electricity ($/kWh)	$ 0.18	$ 0.28	$ 0.23

* assumes 80% efficiency natural gas boiler

Table 3. Generalized Microturbine Economics

Costs and Benefits

Introduction

This chapter presents a generalized overview of the costs and benefit of selected DES technology options, including: capital costs, operating costs and total costs; power-related benefits; energy efficiency benefits; and environmental benefits. It cannot be overstressed that the generalized characterization of technologies (including efficiencies and costs) in this report should not be applied to specific cases without a case-specific evaluation of loads, densities, fuel and electricity costs and other unique circumstances. Further, in order to fully assess a potential district energy system, a long-term economic proforma analysis of revenues and expenses, including a build-up of customer base and plant capacity is required to fully reflect the internal rate of return on the multi-year stream of investments. That level of analysis was beyond the scope of work for this study.

Fuel and Electricity Costs

Among the many variables, the costs of fuel and electricity are key cost/benefit drivers. Further, theses costs, particularly electricity, can vary significantly within the COG region and from customer to customer. Therefore, in the economic analysis we have run sensitivity analysis with two alternative power price assumptions.

Natural Gas

The current delivered (burner tip) price of natural gas for commercial sector and industrial sector customers are summarized in Table 4. There is significant volatility in natural gas prices, as illustrated in Figure 16 (for commercial sector) and Figure 17 (for industrial sector). COG region prices are higher than U.S. averages. Natural gas prices projections by the U.S. Energy Information Administration for the South Atlantic region, converted to constant 2011 dollars per million Btu, are shown in Figure 18.

	Commercial	Industrial
District of Columbia	$ 12.48	
Maryland	$ 10.48	$ 8.54
Virginia	$ 9.91	$ 6.96
Average	$ 10.96	$ 7.75

Table 4. Current Delivered Natural Gas Prices in the COG Region for Commercial and Industrial Customers[13]

[13] Average prices Jan.-Aug. 2011, per *U.S. Energy Information Administration, http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm*

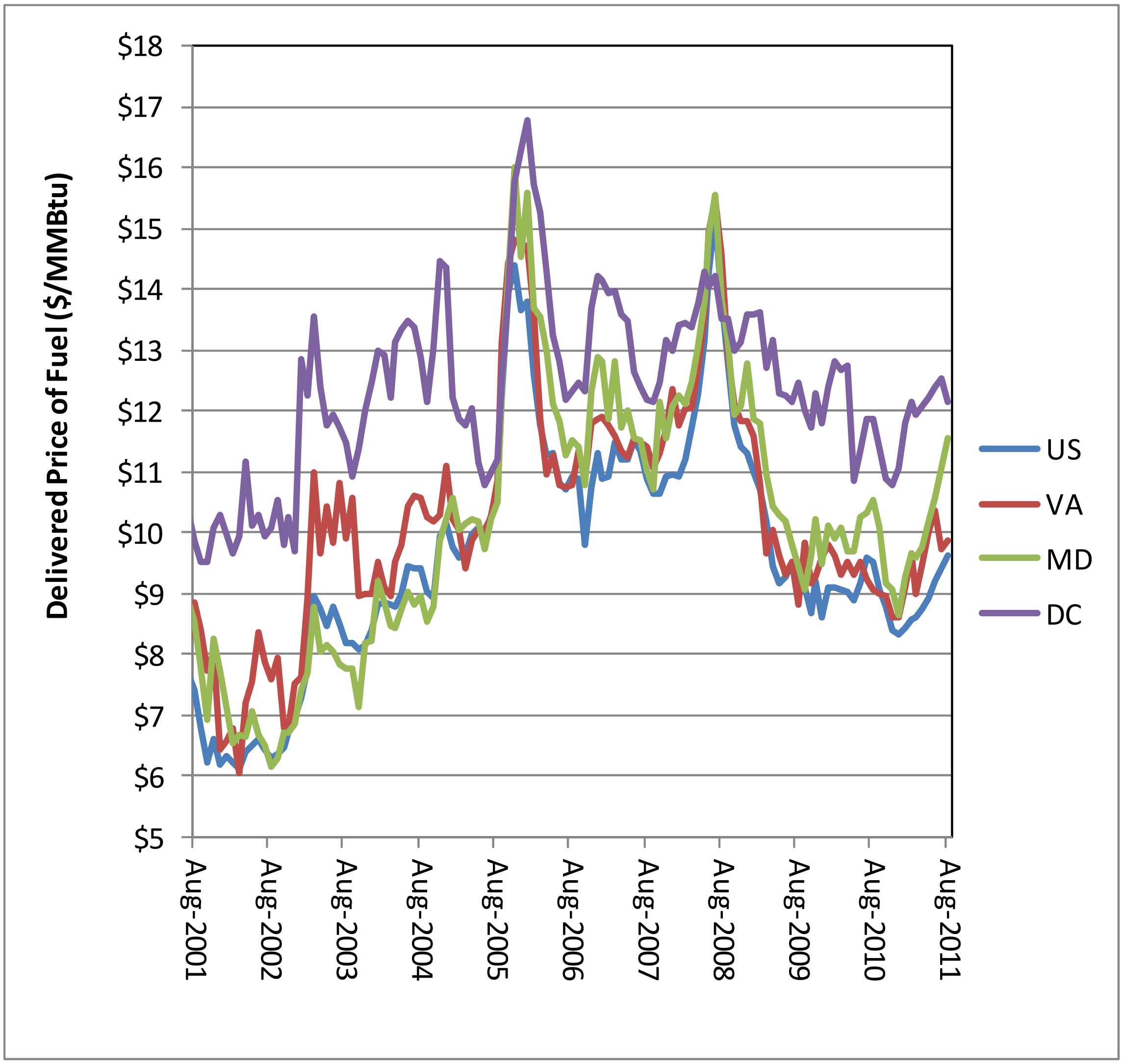

Figure 16. Historical Delivered Natural Gas Prices for Commercial Customers (2001-2011) in Virginia, Maryland, District of Columbia and U.S. Average [14]

[14] *U.S. Energy Information Administration, http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm*

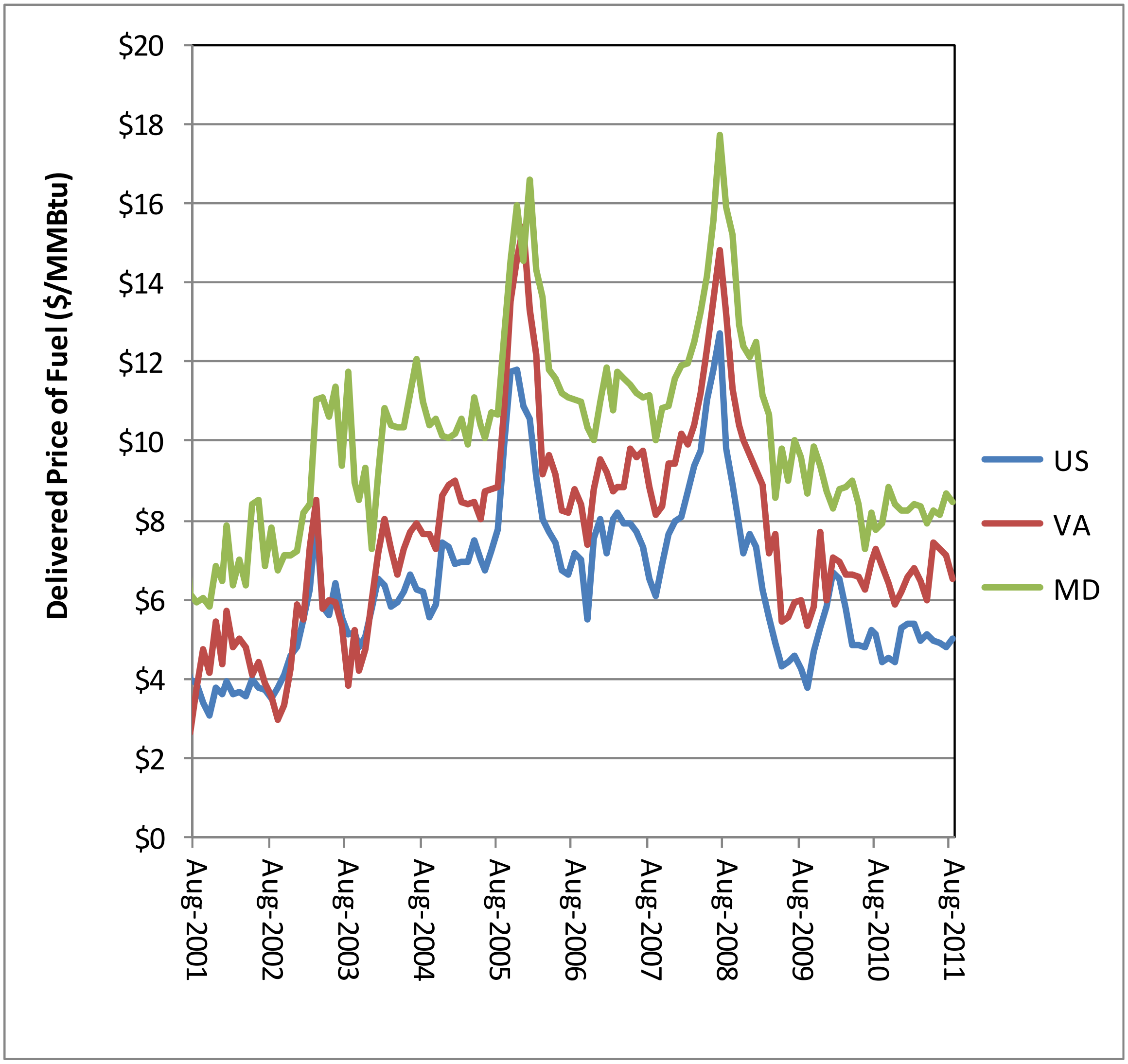

Figure 17. Historical Delivered Natural Gas Prices for Industrial Customers (2001-2011) in Virginia, Maryland and U.S. Average[15]

[15] *U.S.. Energy Information Administration, http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm*

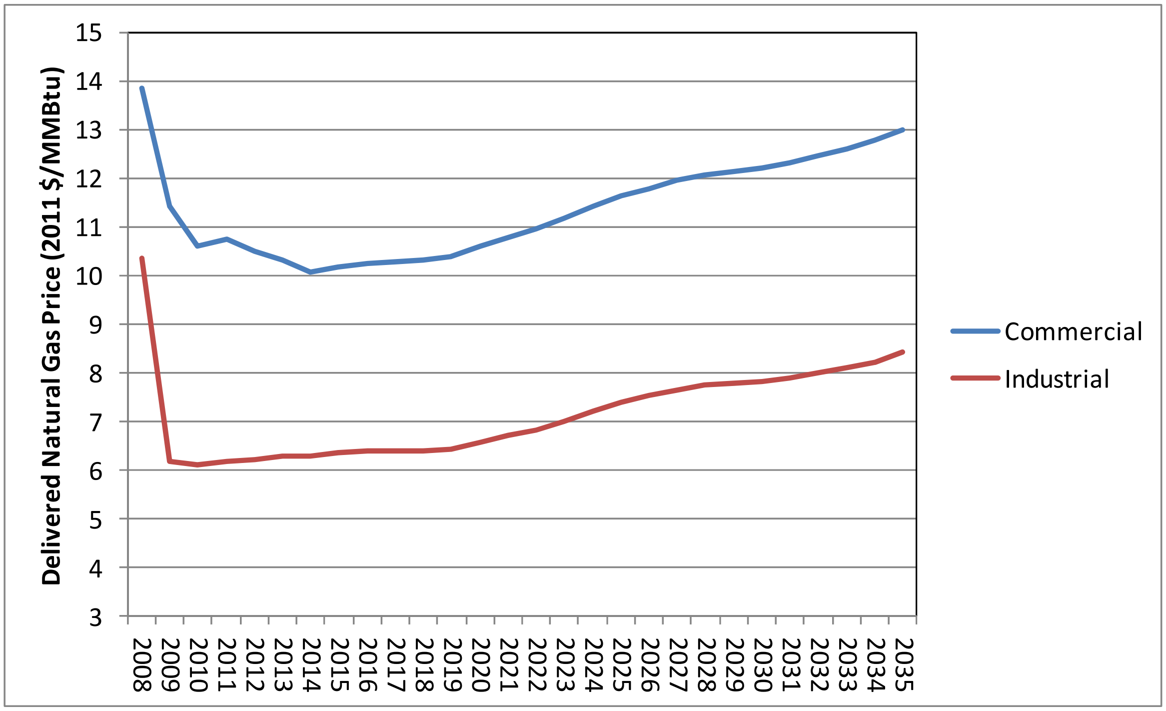

Figure 18. Projected South Atlantic Region Delivered Natural Gas Prices (Actual 2008-2009, Projections 2010-2035)[16]

Based on the historical trends and projections we will assume that delivered natural gas prices for individual buildings will be $11.00 per MMBtu for the later economic analysis. The delivered gas cost for district energy options will be assumed to be $8.50 per MMBtu, with the DES having a price advantage due to purchase of higher volumes of natural gas, but not the full average price advantage reflected by the industrial sector prices.

[16] U.S. Energy Information Administration, Annual Energy Outlook 2011, Natural Gas Delivered Prices by End-Use Sector and Census Division, Reference case.

Electricity

Delivered Cost of Power

Electricity prices vary significantly in the region, as shown in Table 5. Analysis of electricity bills from commercial building operators in the region also shows a range across the region from 8.4 cents to 13.8 cents per kWh.

	Commercial	Industrial
District of Columbia	12.7	7.6
Maryland	11.4	9.3
Virginia	8.2	6.9
Average	10.8	7.9

Table 5. Delivered Prices of Electricity in the COG Region for Commercial and Industrial Customers, July 2011[17]

In the later economic analysis we will calculate results using 8.0 cents and 13.5 cents per kWh for individual building customer electricity costs, for the "Base Case" and "High Elec." scenarios, respectively. For district energy systems we assume 6.5 cents and 9.0 cents per kWh for the "Base Case" and "High Elec." scenarios, respectively, with the district energy system able to reduce power costs due to its size as well as the ability to reduce peak power demand.

PJM and the Wholesale Market

PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. PJM's Economic Load Response program enables demand resources to voluntarily respond to PJM locational marginal prices (LMP) by reducing consumption and receiving a payment for the reduction. Using the day-ahead alternative, qualified market participants may offer to reduce the load they draw from the PJM system in advance of real-time operations and receive payments based on day-ahead LMP for the reductions. The economic program provides access to the wholesale market to end-use customers to curtail consumption when PJM LMPs reach a level where it makes economic sense.

Demand Response is a consumer's ability to reduce electricity consumption at their location when wholesale prices are high or the reliability of the electric grid is threatened. Common examples of demand response include: raising the temperature of the thermostat so the air conditioner does not run as frequently, slowing down or stopping production at an industrial operation or dimming/shutting off lights – basically any explicit action taken to reduce load in response to short-term high prices or a signal from PJM.[18]

[17] U.S. Energy Information Administration, Table 5.6.A. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State, July 2011 and 2010.

[18] PJM, "Retail Electricity Consumer Opportunities for Demand Response in PJM's Wholesale Markets" http://www.pjm.com/Search%20Results.aspx?q=Demand%20Response%20Program

Demand Response does not include the reduction of electricity consumption based on normal operating practice or behavior. For example, if a company's normal schedule is to close for a holiday, the reduction of electricity due to this closure or scaled-back operation is not considered a demand response activity in most situations.

Demand reduction through thermal energy storage is built into the assumptions for DES electricity costs. The impact of LMP and the wholesale power market is accounted for in the assumption of revenues from sale of excess CHP power production into the wholesale market. Figure 19 shows daily variations in PJM wholesale power prices during 2011, and indicates the average value for the period analyzed. For a DES incorporating CHP, we have assumed that excess electricity can be sold to the power grid at a wholesale value of $50/MWh (5.0 cents/kWh) in the "Base Case" and $80/MWh (8.0 cents/kWh) in the "High Elec." case.

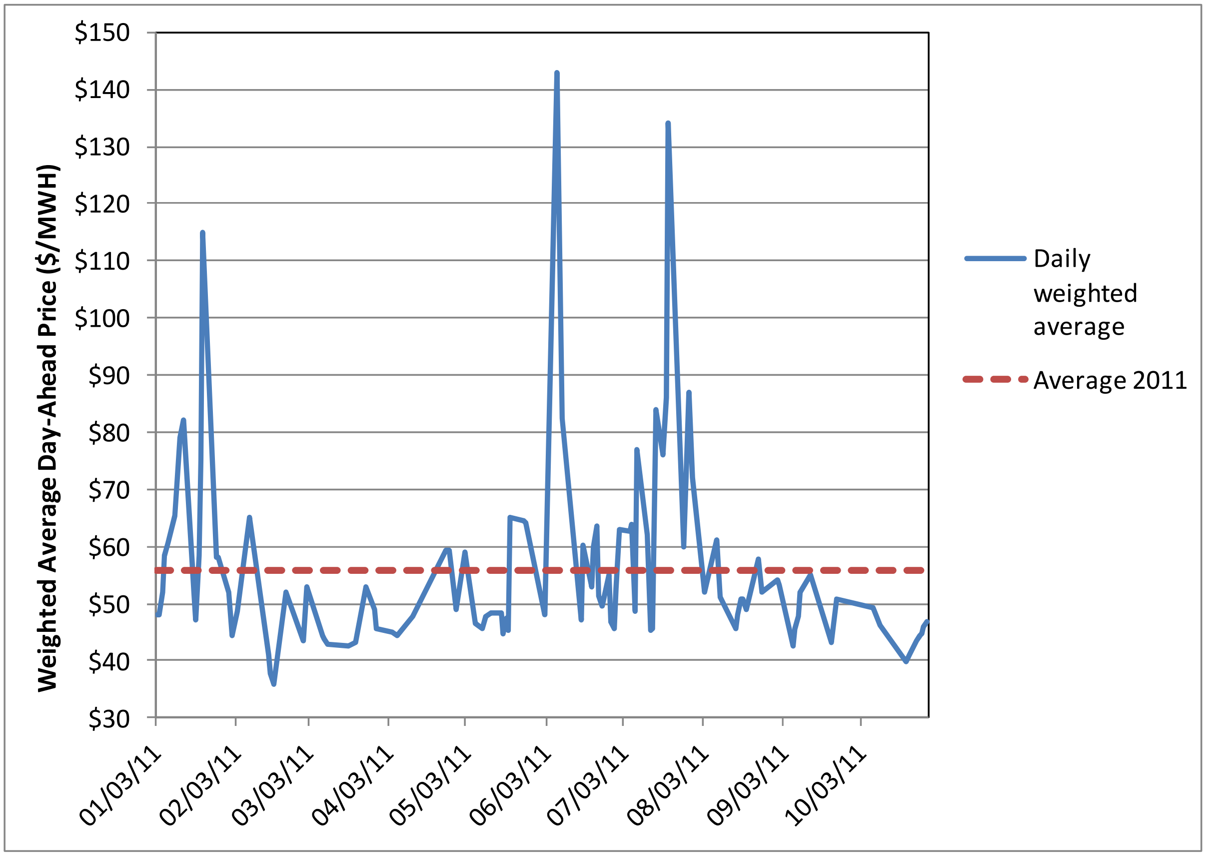

Figure 19. Wholesale Power Prices in PJM 2011[19]

[19] U.S. Energy Information Administration, http://www.eia.gov/electricity/wholesale/index.cfm

Renewable Energy Certificates

Renewable Energy Certificates (RECs), also known as Green tags, Renewable Energy Credits, Renewable Electricity Certificates, or Tradable Renewable Certificates, are tradable, non-tangible energy commodities in the that represent proof that 1 MWh of electricity was generated from an eligible renewable energy resource.

These certificates can be sold and traded or bartered, and the owner of the REC can claim to have purchased renewable energy. According to the U.S. Department of Energy's Green Power Network,[20] RECs represent the environmental attributes of the power produced from renewable energy projects and are sold separately from commodity electricity.

There are two main markets for renewable energy certificates in the United States - compliance markets and voluntary markets. Compliance markets are created by policies in Maryland and the District of Columbia and other states called Renewable Portfolio Standard. In these states, the electric companies are required to supply a certain percent of their electricity from renewable generators by a specified year.

In Virginia there is only a non-binding goal for renewable electricity, so it is a voluntary market, in which customers choose to buy renewable power out of a desire to use renewable energy. Prices for RECs in voluntary markets were $1.00 per MWh ($0.001 per kWh) or less during 2010. [21]

Since none of the community energy options presented in this analysis incorporate qualifying renewable electricity generation, there is no impact on the economic analysis.

Parameters for Generalized System

Loads

In the prior chapter the concept of heating and cooling load duration curves was presented, with illustration of such curves for a generalized district energy system in the Washington DC climate. This generalized system is assumed to serve a mixed use development composed of the mix of building space shown in Table 6.

Energy load characteristics for the generalized customer base are shown in Table 7. Note that the peak demands account for load diversity, i.e., the fact that not all customers have a peak demand at the same time.

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[20] U.S. Department of Energy, Energy Efficiency and Renewable Energy, http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml

[21] U.S. Department of Energy, Energy Efficiency and Renewable Energy, http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5

Office	4.5
Residential	3.0
Retail	1.5
Hotel	1.0
Total	10.0

Table 6. Assumed District Energy System Customer Base by Building Type (million square feet)

Heating

Peak heating demand (MMBtu/hr)	140
Annual heating energy (MMBtu)	275,205

Cooling

Peak cooling demand (tons)	13,802
Annual cooling energy (ton-hrs)	27,613,103

Table 7. Assumed Peak Demand and Annual Energy Consumption for Heating and Cooling

Distribution Systems

The district energy system is assumed to have a heating load density of 11.5 MMBtu of annual delivered heat per trench foot of distribution. This is in-between the "medium" and "high" density in Table 1. For this hypothetical system there would be 24,000 trench feet of distribution. The distribution system would consist of four pipes: heating supply, heating return, cooling supply and cooling return. The largest heating pipe (coming out of the plant) would probably be 16 inches in diameter, with the largest cooling pipe probably 30 inches.

The piping is assumed to be pre-insulated steel pipe as described above under "Distribution Systems".

Building Interface

Buildings are assumed to interface with the district heating system indirectly, using a heat exchanger as described above under "Building Energy Transfer Stations". We assume that 35% of the cooling system connections are indirect and 65% are direct (no heat exchanger). The extent of use of indirect cooling connections is dependent on system- and building-specific hydraulic factors relating to system operating pressures, height of building interface and other factors.

Operating Costs

Key operating cost assumptions for the DES are summarized in Table 8. As noted above, electricity costs can vary significantly within the COG region depending on the local utility's tariffs and a particular customer's load pattern. It is assumed that the DES achieves electricity cost savings with the incorporation of thermal energy storage, which reduces peak power demand and peak power costs. Natural gas costs can vary significantly based on broad market forces and depending on the particular tariff or purchase contract under which the gas is procured, as described above.

		District Energy System	
Costs		**Base Case**	**High Elec.**
Natural gas	/MMBtu	$ 8.50	
Biomass	/MMBtu	$ 4.00	
Electricity	/kWh	$ 0.065	$ 0.090
Water	/1000 gal.	$ 3.68	
Sewer	/1000 gal.	$ 8.51	
Water treatment chemicals	/1000 gal.	$ 0.85	
Revenues			
Sale of excess power	/kWh	$ 0.050	$ 0.080

Table 8. District Energy System Operating Cost and Electricity Sales Revenue Assumptions

Costs of Community Energy Technology Options

Following is a simplified and generalized analysis of the costs of a range of DES technology configurations. It is important to stress that there are many case-specific variables that affect the economics of a specific, "real-world" system.

Community Energy Technology Scenarios

Technology types and capacities for 8 community energy technology scenarios are summarized in Table 9. In each option, the baseload heating capacity is sized to provide 50% of the peak heating load, with the remainder provided by natural gas boilers. In each option except #1, a thermal storage tank is used primarily for chilled water storage, but during winter it is switched to hot water storage. In all options, sufficient redundant capacity is assumed in order to provide "n+1" capacity, i.e., peak demand can be met even if the largest unit is out of service. The options are described below.

1. Boilers & Chillers – Natural gas boiler provide all heat, and electric centrifugal chillers provide all cooling.

2. Engine CHP – Baseload heating is provided by recovery of heat from exhaust gas and jacket water from three 7.5 MWe natural gas fired reciprocating engines. This CHP capacity was sized to supply 50% of the peak heating demand. Absorption chiller capacity is sized to use the heat output of CHP. Electric centrifugal chillers in conjunction with

chilled water storage are used to provide peaking capacity. Thermal energy storage is used to maximize economic operation of the CHP and reduce peak power demand for cooling.

3. Turbine CHP – Baseload heating is provided by recovery of exhaust gas from two 6.7 MWe natural gas fired combustion turbines. This CHP capacity was sized to supply 50% of the peak heating demand. Absorption chiller capacity is sized to use the heat output of CHP. Electric centrifugal chillers in conjunction with chilled water storage are used to provide peak cooling capacity. Thermal energy storage is used to maximize economic operation of the CHP and reduce peak power demand for cooling.

4. Combined Cycle CHP – Baseload heating is provided by one 23.5 MWe natural gas fired combined cycle turbine plant. This CHP capacity was sized to supply 50% of the peak heating demand. Absorption chiller capacity is sized to use the heat output of CHP. Electric centrifugal chillers in conjunction with chilled water storage are used to provide peak cooling capacity. Thermal energy storage is used to maximize economic operation of the CHP and reduce peak power demand for cooling.

5. Biomass Boiler – Baseload heating is provided by a 72 MMBtu/hour biomass fired boiler using urban waste wood and/or forestry residue. The biomass capacity was sized to supply 50% of the peak heating demand. Absorption chiller capacity is sized to use the heat output of biomass boiler. Electric centrifugal chillers in conjunction with chilled water storage are used to provide peak cooling capacity. Thermal energy storage is used to maximize economic operation of the biomass boiler and reduce peak power demand for cooling.

6. Ground Source Heat Pumps – Baseload heating is provided by 72 MMBtu/hour of ground source heat pump capacity. The ground source capacity was sized to supply 50% of the peak heating demand and 34% of the cooling capacity. Electric centrifugal chillers in conjunction with chilled water storage are used to provide peak cooling capacity. Thermal energy storage is used to maximize economic operation of the geothermal capacity and reduce peak power demand for cooling.

7. Waste Heat Recovery – Baseload heating is provided by 72 MMBtu/hour of recovered low-grade waste heat. The waste heat recovery capacity was sized to supply 50% of the peak heating demand. For this hypothetical scenario the heat source was assumed to be over 4 miles from the DES. Electric centrifugal chillers in conjunction with chilled water storage are used to provide cooling. Thermal energy storage is used to maximize economic operation of the waste heat recovery capacity and reduce peak power demand for cooling.

8. Solar – Baseload heating is provided by 72 MMBtu/hour of flat-plate solar collector heat. The solar capacity was sized to supply 50% of the peak heating demand. Electric centrifugal chillers in conjunction with chilled water storage are used to provide cooling. Thermal energy storage is used to maximize economic operation of the solar capacity and reduce peak power demand for cooling.

	1	2	3	4	5	6	7	8
	Boilers & Chillers	**Engine CHP**	**Turbine CHP**	**Combined Cycle CHP**	**Biomass Boiler**	**Ground Source Heat Pumps**	**Waste Heat Recovery**	**Solar**
District Heating								
Natural gas boilers								
Capacity/unit (MMBtu/hr)	30	30	24	22	22	22	22	22
# of units	6	3	4	6	6	6	6	6
Capacity (MMBtu/hr)	180	90	96	132	132	132	132	132
CHP								
Type		Engine	Turbine	Com. Cycle				
Fuel		Nat. Gas	Nat. Gas	Nat. Gas				
Power capacity/unit (MW)	0	7.5	6.7	23.5		0	0	0
Power to heat ratio	1.00	0.98	0.63	1.13		1.00	1.00	1.00
Thermal capacity/unit (MMBtu/hr)	-	26.12	36.30	70.98		-	-	-
# of units	0	3	2	1		0	0	0
Power capacity (MW)	0.0	22.5	13.4	23.5		0.0	0.0	0.0
Thermal capacity (MMBtu/hr)	-	78	73	71		-	-	-
Other thermal capacity (MMBtu/hr)								
Biomass boiler					72			
Ground source heat pumps	0	0	0	0	0	72	0	0
Industrial waste heat recovery	0	0	0	0	0	0	72	0
Solar	0	0	0	0	0	0	0	72
Hot water storage	-	14	14	14	14	14	14	14
Total thermal capacity (MMBtu/hr)								
All units	180	183	183	217	219	219	219	219
Minus largest unit	150	157	147	146	146	146	146	146
District Cooling								
Electric centrifugal chillers								
Capacity/unit (tons)	1,775	1,775	1,775	1,775	1,775	1,775	1,775	1,775
# of units	8	6	6	6	6	6	8	8
Capacity (tons)	14,198	10,648	10,648	10,648	10,648	10,648	14,198	14,198
Absorption chillers								
Capacity/unit (tons)	-	1,959	1,815	1,774	1,774	-	-	-
# of units	-	2	2	2	2	-	-	-
Capacity (tons)	-	3,918	3,630	3,549	3,549	-	-	-
Thermal energy storage								
Capacity (tons)	1,775	1,775	1,775	1,775	1,775	1,775	1,775	1,775
Ground source heat pumps								
capacity (tons)	-	-	-	-	-	4,643	-	-
Total capacity (tons)								
All units	15,972	16,341	16,053	15,972	15,972	17,066	15,972	15,972
Minus largest unit	14,198	14,566	14,278	14,197	14,197	15,291	14,198	14,198
Power generation								
Total capacity (MW)								
All units	-	23	13	24	-	-	-	-
Minus largest unit	-	15	7	-	-	-	-	-

Table 9. District Energy Technology Scenarios

Capital Costs

Generalized capital costs are summarized in Table 10. These estimates include all costs, such as land acquisition, plant building, civil costs, all mechanical and electrical equipment, all distribution systems including service lines, and all costs for the Energy Transfer Stations (ETS) connecting the district systems to the building HVAC systems. In this simplified economic analysis, we assume that all capital costs are incurred in one step.

Annual Costs

The operations of each system are summarized in Table 13, Table 12 and Table 13.

- Table 11 summarizes annual operations for the heating system, including heat produced from each component of the plant, energy conversion efficiencies, input fuels and electricity, and (for CHP) electricity produced. CHP fuel input and electricity output is attributed pro-rata to heating operations based on the share of CHP heat output that is used for heating.
- Table 12 summarizes annual operations for the cooling system, including cooling energy produced from each component of the plant, energy conversion efficiencies, input fuels and electricity, and (for CHP) electricity produced. CHP fuel input and electricity output is attributed pro-rata to cooling operations based on the share of CHP heat output that is converted to cooling energy via absorption chillers.
- Table 13 summarizes peak power demand conditions as well as tallying total annual fuel and electricity consumption.

Table 14 summarizes two sets of assumptions for capital amortization. The “market” scenario reflects a fully private sector approach. The “low cost” scenario assumes that low-cost debt can be obtained and that equity investors accept a relatively low rate of return on equity based on very tight customer contracts and/or other means of high assurance that revenues will be realized.

Table 15 summarizes operation and maintenance cost assumptions, including labor, maintenance and supplies.

Table 16 shows annual costs including base case gas and electricity costs and “market” amortization of capital. Note that this simplified economic analysis does not account for ramp-up of capacity and loads; in effect, the analysis is based on the assumption that the full system is constructed in one step and that service to the full customer base occurs in the first year of operation. Excess CHP electricity not required for DES operations is assumed to be sold to the grid for $0.05 per kWh under Base Case assumption and $0.08 per kWh for the High Elec. price assumption.

	1	2	3	4	5	6	7	8
	Boilers & Chillers	**Engine CHP**	**Turbine CHP**	**Combined Cycle CHP**	**Biomass Boiler**	**Ground Source Heat Pumps**	**Waste Heat Recovery**	**Solar**
Capital Costs (million $)								
PLANT								
Land purchase	$ 4.4	$ 9.2	$ 7.0	$ 9.3	$ 8.0	$ 7.0	$ 6.0	$ 6.0
Heating Plant								
Natural gas boilers	$ 9.0	$ 4.5	$ 4.8	$ 6.6	$ 6.6	$ 6.6	$ 6.6	$ 6.6
Biomass boilers	$ -	$ -	$ -	$ -	$ 16.3	$ -	$ -	$ -
Industrial waste heat recovery	$ -	$ -	$ -	$ -	$ -	$ -	$ 6.5	$ -
Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 43.5
Cooling Plant								
Electric centrifugal chillers	$ 29.8	$ 22.4	$ 22.4	$ 22.4	$ 22.4	$ 22.4	$ 29.8	$ 29.8
Absorption chillers	$ -	$ 9.4	$ 8.7	$ 8.5	$ 8.5	$ -	$ -	$ -
CHP Plant	$ -	$ 29.2	$ 22.8	$ 29.4	$ -	$ -	$ -	$ -
Thermal energy storage	$ 1.4	$ 1.4	$ 1.4	$ 1.4	$ 1.4	$ 1.4	$ 1.4	$ 1.4
Ground source heat pumps	$ -	$ -	$ -	$ -	$ -	$ 30.2	$ -	$ -
Total plant	$ 44.7	$ 76.2	$ 67.1	$ 77.5	$ 63.2	$ 67.5	$ 50.3	$ 87.3
DISTRIBUTION								
Heating	$ 6.7	$ 6.7	$ 6.7	$ 6.7	$ 6.7	$ 6.7	$ 6.7	$ 6.7
Cooling	$ 10.5	$ 10.5	$ 10.5	$ 10.5	$ 10.5	$ 10.5	$ 10.5	$ 10.5
Total distribution	$ 17.2	$ 17.2	$ 17.2	$ 17.2	$ 17.2	$ 17.2	$ 17.2	$ 17.2
ENERGY TRANSFER STATIONS (ETS)								
Heating energy transfer stations	$ 1.9	$ 1.9	$ 1.9	$ 1.9	$ 1.9	$ 1.9	$ 1.9	$ 1.9
Cooling energy transfer stations	$ 3.7	$ 3.7	$ 3.7	$ 3.7	$ 3.7	$ 3.7	$ 3.7	$ 3.7
Total ETS	$ 5.7	$ 5.7	$ 5.7	$ 5.7	$ 5.7	$ 5.7	$ 5.7	$ 5.7
TOTAL	$ 67.6	$ 99.0	$ 90.0	$ 100.4	$ 86.1	$ 90.4	$ 73.2	$ 110.1
Capital Costs by Thermal Service (million $)								
Heating	$ 19.6	$ 39.0	$ 33.5	$ 41.2	$ 30.9	$ 37.8	$ 24.3	$ 61.3
Cooling	$ 47.9	$ 60.1	$ 56.5	$ 59.2	$ 55.2	$ 52.6	$ 48.9	$ 48.9
Total	$ 67.6	$ 99.0	$ 90.0	$ 100.4	$ 86.1	$ 90.4	$ 73.2	$ 110.1

Table 10. Generalized District Energy System Capital Costs

			1	2	3	4	5	6	7	8
			Boilers & Chillers	**Engine CHP**	**Turbine CHP**	**Combined Cycle CHP**	**Biomass Boiler**	**Ground Source Heat Pumps**	**Waste Heat Recovery**	**Solar**
BASELOAD HEATING SOURCES										
% of annual heating energy supplied by baseload resource			100%	86%	86%	86%	86%	73%	58%	26%
% of annual cooling energy supplied by baseload resource			100%	50%	50%	50%	50%	74%	100%	100%
Baseload Boilers										
Annual energy	Produced annual heating energy	MMBtu	288,868							
Fuel input	Annual natural gas fuel consumption	MMBtu	339,845							
CHP										
Annual energy	Produced heating energy from CHP for heating	MMBtu		248,427	248,427	248,427				
	Potential produced cooling energy from CHP	ton-hrs		14,308,998	14,308,998	14,308,998				
Annual energy	Electricity output	MWH		141,180	90,758	162,789				
Fuel input	Power generation heat rate	Btu/kWhe		9,111	11,778	8,556				
	Annual fuel consumption	MMBtu		1,286,304	1,068,932	1,392,749				
Biomass Boiler										
Annual energy	Produced heat for heating	MMBtu					248,427			
	Produced heat for cooling	MMBtu					243,253			
Fuel input	Annual natural biomass fuel consumption	MMBtu					756,431			
Heat Pumps										
Annual energy	Produced annual heating energy	MMBtu						211,163		
	Delivered annual heating energy	MMBtu						201,175		
Energy input	Annual electricity consumed	MWhe						19,334		
Baseload Heat Exchangers or Solar Energy										
Annual energy	Produced annual heating energy	MMBtu							165,612	74,154
	Delivered annual heating energy	MMBtu							158,573	71,003
	Waste heat transmission pumping energy	MWH							828	
PEAKING HEAT SOURCES										
Annual produced heating energy supplied by peaking resources		MMBtu		40,442	40,442	40,442	40,442	77,706	123,257	214,714
Peaking boiler efficiency				82%	82%	82%	82%	82%	82%	82%
Annual fuel consumption		MMBtu		49,319	49,319	49,319	49,319	94,763	150,313	261,846

Table 11. District Energy Systems Annual Operations -- Heating

			1	2	3	4	5	6	7	8
			Boilers & Chillers	**Engine CHP**	**Turbine CHP**	**Combined Cycle CHP**	**Biomass Boiler**	**Ground source heat pumps**	**Waste heat recovery**	**Solar**
BASELOAD COOLING SOURCES										
Electric Centrifugal Chillers										
Annual energy	Produced annual cooling energy (inc. to TES)	ton-hrs	28,838,750						28,838,750	28,838,750
	Delivered annual cooling energy (inc. to TES)	ton-hrs	27,613,103						27,613,103	27,613,103
Energy input	Annual electricity consumed	MWH	21,575						21,575	21,575
Absorption Chiller Systems										
Annual energy	Produced annual cooling energy	ton-hrs		12,162,648	12,162,648	12,162,648	12,162,648			
	Delivered annual cooling energy	ton-hrs		11,645,736	11,645,736	11,645,736	11,645,736			
Energy input	Annual heat consumed for driving energy	MMBtu		243,253	243,253	243,253	243,253			
	Annual electricity consumed	MWH		3,033	3,033	3,033	3,033			
Heat Pump Cooling										
Annual energy	Produced annual cooling energy	ton-hrs						21,423,656		
	Delivered annual cooling energy	ton-hrs						20,513,151		
Energy input	Annual electricity consumed	MWH						17,934		
Total Baseload Cooling Energy Produced		ton-hrs	28,838,750	12,162,648	12,162,648	12,162,648	12,162,648	21,423,656	28,838,750	28,838,750
PEAKING COOLING SOURCES										
Annual produced cooling energy supplied by peaking resources		ton-hrs		16,676,102	16,676,102	16,676,102	16,676,102	7,415,094	-	-
Electricity COP				4.0	4.0	4.0	4.0	4.0		
Annual electricity consumed		MWH		14,658	14,658	14,658	14,658	6,518		

Table 12. District Energy System Annual Operations -- Cooling

		1	2	3	4	5	6	7	8
		Boilers & Chillers	**Engine CHP**	**Turbine CHP**	**Combined Cycle CHP**	**Biomass Boiler**	**Ground source heat pumps**	**Waste heat recovery**	**Solar**
SUMMER PEAK OPERATIONS									
Cooling production (tons)									
Electric centrifugal chillers		12,423	8,505	8,793	8,874	8,874	7,780	12,423	12,423
Absorption chillers			3,918	3,630	3,549	3,549			
Heat pumps							4,643		
Thermal storage		1,775	1,775	1,775	1,775	1,775	1,775	1,775	1,775
Total		14,198	14,198	14,198	14,198	14,198	14,198	14,198	14,198
Net summer peak power demand (MW)									
Electric centrifugal chiller systems		7.0	4.8	4.9	5.0	5.0	4.4	7.0	7.0
Absorption chiller systems		-	1.0	0.9	0.9	0.9			
Heat pump systems							3.9		
Distribution pumping and plant house		0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
CHP		-	(22.5)	(13.4)	(23.5)	-	-	-	-
Total		7.8	(15.9)	(6.7)	(16.8)	6.7	9.1	7.8	7.8
ANNUAL DISTRIBUTION PUMPING ENERGY									
Heating distribution	MWH	664	664	664	664	664	664	664	664
Cooling distribution	MWH	2,163	2,163	2,163	2,163	2,163	2,163	2,163	2,163
Total	MWH	2,827	2,827	2,827	2,827	2,827	2,827	2,827	2,827
TOTAL FUEL AND ELECTRICITY CONSUMPTION									
Natural gas fuel consumption (MMBtu)	MMBtu	339,845	1,335,623	1,118,251	1,442,068	49,319	94,763	150,313	261,846
Biomass fuel consumption (MMBtu)						756,431			
Heating electricity consumption	MWH	664	664	664	664	664	19,999	1,492	664
Cooling electricity consumption	MWH	23,738	19,854	19,854	19,854	19,854	26,615	23,738	23,738
Electricity production and consumption									
Consumption	MWH	24,402	20,518	20,518	20,518	20,518	46,614	24,402	24,402
Production	MWhe	-	141,180	90,758	162,789	-	-	-	-
Net Consumption	MWhe	24,402	(120,661)	(70,240)	(142,270)	20,518	46,614	24,402	24,402

Table 13. District Energy Systems Annual Operations -- Peak Power Demand and Annual Fuel and Electricity Consumption

	Market	Low Cost
Debt/equity ratio	0.60	0.70
Debt interest rate	7.0%	4.0%
Equity hurdle rate	15.0%	12.0%
Weighted average cost of capital	10.2%	6.4%
Term	20	20
Capital recovery factor	0.1191	0.0900

Table 14. Capital Amortization Assumptions

	1	2	3	4	5	6	7	8
	Boilers & Chillers	**Engine CHP**	**Turbine CHP**	**Combined Cycle CHP**	**Biomass Boiler**	**Ground Source Heat Pumps**	**Waste Heat Recovery**	**Solar**
Labor (FTE)	7.0	8.0	8.0	10.0	14.0	8.0	7.0	7.0
Labor rate ($/FTE)	$ 90,000	$ 90,000	$ 90,000	$ 90,000	$ 90,000	$ 90,000	$ 90,000	$ 90,000
CHP maintenance costs ($/MWHe)	$ -	$ 11.00	$ 10.00	$ 8.00	$ -	$ -	$ -	$ -
Boiler maintenance costs (% of capital)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Waste heat recovery maintenance costs (% of capital)	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
Solar maintenance costs (% of capital)	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
Electric chiller maintanance costs ($/ton/yr)	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Absorption chiller maintanance costs ($/ton/yr)	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Thermal storage maintenance costs (% of capital)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
Ground source heat pump ($/ton/yr)	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Water/sewer ($/gal.)	$ 12.19	$ 12.19	$ 12.19	$ 12.19	$ 12.19	$ 12.19	$ 12.19	$ 12.19
Water treatment chemicals ($/gal.)	$ 0.85	$ 0.85	$ 0.85	$ 0.85	$ 0.85	$ 0.85	$ 0.85	$ 0.85
Distribution system maintenance costs (% of capital)	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
ETS maintenance costs (% of capital)	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%

Table 15. Operation and Maintenance Cost Assumptions

	1	2	3	4	5	6	7	8
	Boilers & Chillers	Engine CHP	Turbine CHP	Combined Cycle CHP	Biomass Boiler	Ground Source Heat Pumps	Waste Heat Recovery	Solar
Annual Costs (million $)								
District Heating								
Non-thermal revenue		$ (3.57)	$ (2.29)	$ (4.11)				
Capital amortization	$ 2.34	$ 4.64	$ 3.99	$ 4.90	$ 3.68	$ 4.50	$ 2.90	$ 7.30
Natural gas	$ 2.89	$ 5.94	$ 5.01	$ 6.40	$ 0.42	$ 0.81	$ 1.28	$ 2.23
Biomass					$ 2.35			
Purchased electricity	$ 0.04	$ 0.01	$ 0.01	$ 0.01	$ 0.04	$ 1.30	$ 0.10	$ 0.04
Maintenance	$ 0.20	$ 0.89	$ 0.57	$ 0.81	$ 0.48	$ 0.27	$ 0.25	$ 0.37
Labor	$ 0.25	$ 0.29	$ 0.29	$ 0.36	$ 0.50	$ 0.29	$ 0.25	$ 0.25
Total	$ 5.72	$ 8.20	$ 7.58	$ 8.37	$ 7.47	$ 7.17	$ 4.77	$ 10.19
District Cooling								
Non-thermal revenue		$ (3.49)	$ (2.25)	$ (4.03)	$ -			
Capital amortization	$ 5.71	$ 7.15	$ 6.72	$ 7.05	$ 6.58	$ 6.26	$ 5.82	$ 5.82
Natural gas		$ 5.41	$ 4.50	$ 5.86	$ -			
Biomass					$ 2.30			
Purchased electricity	$ 1.61	$ 0.19	$ 0.19	$ 0.19	$ 1.29	$ 1.73	$ 1.61	$ 1.61
Maintenance	$ 0.41	$ 1.19	$ 0.86	$ 1.05	$ 0.41	$ 0.32	$ 0.41	$ 0.41
Water/sewer/chemicals	$ 0.94	$ 1.30	$ 1.30	$ 1.30	$ 1.30	$ 0.94	$ 0.94	$ 0.94
Labor	$ 0.38	$ 0.43	$ 0.43	$ 0.54	$ 0.76	$ 0.43	$ 0.38	$ 0.38
Total	$ 9.05	$ 12.18	$ 11.76	$ 11.97	$ 12.63	$ 9.68	$ 9.15	$ 9.15
Total District Heating and Cooling	$ 14.76	$ 20.38	$ 19.33	$ 20.34	$ 20.11	$ 16.85	$ 13.93	$ 19.34

Table 16. Annual Costs for District Energy Scenarios with Base Case Assumptions

Customer Benefits

Value Proposition

Before addressing the economic comparison between DES options and conventional building approaches, it is appropriate discuss the total context for decisions regarding whether or not to buy district energy services.

People buy based on how they perceive the "value proposition" of a good or service, i.e. the total mix of attributes and benefits received compared with the cost. Unless what is being purchased is a true commodity (in which one seller's product is exactly the same as another's), the questions is not simply "Which option costs less?" but rather "Which option delivers the greatest total value most cost-effectively?"

Some of the attributes of district energy service may be difficult to quantify in dollars, but the history of the district energy industry shows that a wide range of benefits, summarized below, are frequently an important factor in the district energy value proposition.

Architectural Flexibility

Without the need for boilers, chillers or cooling towers, architects have greater flexibility to create an attractive design, with the ***roof free of smoke stacks and cooling towers***. In addition, roof or interior space that would otherwise be dedicated to these systems can be employed for ***value-added facilities***, such as a rooftop swimming pool.


Reduced Capital Costs

District energy service ***reduces capital costs*** in comparison to installation of boiler and chiller systems in the building. The building owner will need to make minor modifications to the building system design to interface with the district system. Hydronic systems, in which heating and cooling is distributed within the building with water, are required for interface with district systems. Hydronic systems have higher capital costs than some types of building heating and cooling systems such as electric resistance heating or unitary heat pumps. However, hydronic systems are superior to these other approaches relative to quality of service and long-term operating costs.

Comfort and Safety

District energy systems provide a ***higher quality of heating and cooling service***, keeping building occupants more comfortable because industrial-grade equipment is used in the central plant and hydronic distribution is used in the building to provide a ***consistent, well-controlled source of heating and cooling***. In addition, specialist attention is focused on optimal operation and maintenance of heating and cooling systems, providing better temperature and humidity control than packaged HVAC equipment and, therefore, a potentially healthier indoor environment. ***Buildings are quieter*** because there is no heavy equipment generating vibration and noise, making tenants happier and allowing them to be more productive. ***Safety concerns are eliminated*** because no fuel is being combusted in the building.

Convenience and Flexibility

From the building manager's standpoint, district energy service is easy, convenient and flexible. ***District energy service eliminates hassles*** associated with managing the equipment, labor, utilities and materials required for operating and maintaining boiler, chiller and cooling tower systems. This allows the manager to ***focus on their core business***, such as attracting and retaining tenants.

From the user's perspective, district energy service is extremely flexible. Heating and cooling energy is ***always available*** in the pipelines, thus avoiding the need to start and stop building equipment. With in-building systems, meeting air-conditioning requirements at night or on weekends can be difficult and costly, particularly when the load is small. With district energy, these needs can be met easily and cost-effectively whenever they occur. The building can use as much or as little energy as needed, whenever needed, without worrying about equipment size or capacity.

Reliability

District energy is more reliable than the conventional approach because district energy systems use highly reliable industrial equipment and can cost-effectively provide ***equipment redundancy***. Staffed with ***professional operators*** around-the-clock, district energy companies are specialists with expert operations and preventive maintenance programs. According to the International

District Energy Association (IDEA), most district energy systems operate at a reliability of "five nines" (99.999%).

Environment

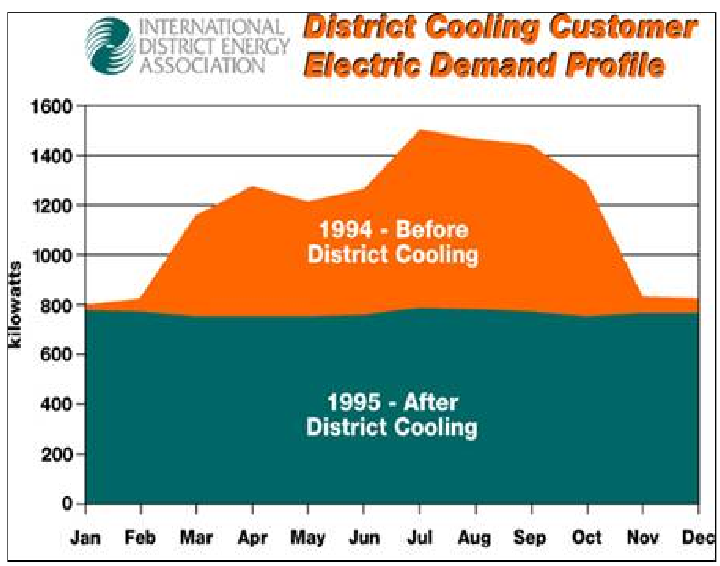
District energy is a green technology, ***using fossil fuels more efficiently*** and providing the infrastructure for tapping ***renewable energy*** for heating and cooling. District energy systems have the ***economies of scale to implement advanced technologies*** such as CHP, renewable thermal energy and thermal energy storage. In a typical power plant, more than 67% of the fuel used to generate power is lost as waste heat. CHP systems capture this heat for use in buildings.

Risk Management

District energy service ***reduces capital and operating risks.*** Capital risks are reduced because no capital is tied up in the building for heating or cooling equipment. Operating risk associated with operation and maintenance of building equipment is eliminated. Costs are more predictable because more of the costs are fixed and less is spent on fuel and electricity, which can be highly volatile in price.

The inherent ***flexibility of district energy systems*** to respond to volatile energy prices and supplies, regulatory constraints and new technology opportunities is an extremely important, but difficult to quantify, benefit for customers. Some developers refer to this as ***"future-proofing"*** a building. A highly significant long-term regulatory constraint is GHG emission reduction. Although laws or regulations to limit GHG reductions are unlikely to be enacted in the current political environment, such policies are inevitable. District energy will be far better able to adapt compared with individual buildings.

District systems are well positioned to take advantage of technology, energy and pricing ***opportunities*** for the benefit of their customers. For example, in response to fluctuations in the supply or price of fuels, it is relatively easy for district systems to ***change the fuel mix*** or ***implement new technologies*** with lower costs and GHG emissions.



District cooling helps position buildings for a more competitive, higher-priced electricity market by reducing power demand. The chart at right shows the actual monthly peak demand for an Ohio office building before and after district cooling. The flat load profile can ***reduce power bills*** because peak power is more expensive.

In a ***competitive real estate market***, the ability to provide superior comfort, predictable costs, green credentials and long-term flexibility will attract and retain tenants and help maintain higher asset value.

Economics

District energy has ***fundamental cost advantages*** over multiple boilers and chillers. District systems use highly efficient equipment that can be operated at optimal levels, can use economies of scale to implement advanced technologies, and have better staff economies than many separate building systems. Further, district systems can take advantage of load diversity. "Diversity" refers to the fact that not all buildings have their peak demand for heating or cooling at the same time. This diversity enables district systems to invest in less peak capacity than would be required if all buildings installed their own equipment, yet provide superior reliability.

Typically, district energy systems charge for service through a fixed charge tied to peak demand and a variable charge for energy consumed. The relationship between a district system and its customers is a lot like the relationship between building owners and tenants. In many cases the structure of a district energy service agreement is analogous to a triple net lease: demand charges are like base rent; and operating costs are passed through.

Comparing district energy service to self-generation requires consideration of ***total capital costs and operating costs***. Capital costs include the installed cost of boilers, chillers, cooling towers, pumps, controls, electrical service and gear, engineering services and spare parts, as well as construction costs to create the space for the equipment. Operating costs include electricity, fuels, maintenance and repair, labor and administration, water, chemicals and supplies. The developer should ask whether he or she can invest marginal capital at a higher rate of return in elements of the building that are more visible and accretive to the market value of the property, in comparison with HVAC system investments.

Self-Generation of Heating and Cooling

With the above discussion of the benefits of district energy service that contribute to the total "value proposition" in mind, this section addresses the costs of "self-generation" of heating and cooling by customers, following by a comparison of self-generation costs with the generalized costs of district energy systems as presented earlier.

Costs for "self-generation" of heating and cooling using building-scale systems will vary significantly depending on specific HVAC systems used, unit costs of natural gas and electricity, building energy usage pattern, building developer/owner cost of capital and investment time horizon and a range of other factors.

There are many different approaches to HVAC system design. Generally, in large multi-story buildings heating and cooling are provided via "hydronic" systems (i.e. hot water and chilled water are piped to air handlers or other equipment within the building), with hot water provided by natural gas boilers and chilled water using electric chillers. Other HVAC approaches, such as electric resistance heating (using baseboard units, electric coils in air handlers, rooftop equipment or other systems), air-to-air heat pumps, water loop heat pumps, direct expansion cooling and other equipment. Some of these systems have lower capital costs compared with boilers and chillers, but have higher operating costs and higher indirect GHG emissions. Economic analysis of such systems is very site-specific and is beyond the scope of this report.

Generalized costs for providing heating and cooling for the assumed district energy system customer base (see Table 6) using building-scale natural gas boilers and electric centrifugal chillers are estimated in Table 17. These estimates cover capital and operating costs for systems to serve all load served by the district energy systems analyzed above. These costs include all mechanical, electrical and civil costs, including construction of building space for the boiler and chiller systems. Base Case energy prices are $11.00 per million Btu natural gas and $0.08 per kWh electricity. In the High Elec. scenarios, electricity is assumed to cost $0.135 per kWh. Capital amortization assumptions are the same as the “market” assumption in Table 14. Other assumptions and calculations for the self-generation analysis are summarized in Table 18.

	Energy Price Assumptions	
	Base Case	**High Elec.**
ANNUAL COSTS (MILLION $)		
Heating		
Capital amortization	$ 1.72	$ 1.72
Natural gas	$ 3.69	$ 3.69
Electricity		
Maintenance	$ 0.29	$ 0.29
Labor	$ 0.50	$ 0.50
Total	$ 6.20	$ 6.20
Cooling		
Capital amortization	$ 6.93	$ 6.93
Electricity	$ 1.89	$ 3.20
Maintenance	$ 0.70	$ 0.70
Water/sewer/chemicals	$ 0.19	$ 0.19
Labor	$ 0.63	$ 0.63
Total	$ 10.34	$ 11.64
Total Annual Costs (million $)		
Natural gas	$ 3.69	$ 3.69
Electricity	$ 1.89	$ 3.20
Heating system maintenance	$ 0.29	$ 0.29
Electric chiller maintenance	$ 0.70	$ 0.70
Labor	$ 1.13	$ 1.13
Water/sewer	$ 0.07	$ 0.07
Water treatment chemicals	$ 0.12	$ 0.04
Total Operating Costs	$ 7.89	$ 9.11
Capital amortization	$ 8.65	$ 8.65
Total Annual Costs	$ 16.54	$ 17.77

Table 17. Estimated Costs for Self-Generation of Heating and Cooling Using For Two Building HVAC Scenarios -- Natural Gas Boilers/Electric Centrifugal Chillers and Electric Resistance Heating/DX Cooling

	Energy Price Assumptions	
	Base Case	High Elec.
AGGREGATE LOADS		
Heating Demand (MMBtu/hr)		
Diversified peak demand	140	140
Undiversified peak demand	165	165
Heating Energy (MMBtu)	275,205	275,205
Cooling Demand (tons)		
Diversified peak demand	13,800	13,800
Undiversified peak demand	17,250	17,250
Cooling Energy (ton-hrs)	27,613,103	27,613,103
INSTALLED CAPACITY		
Natural gas boilers (MMBtu/hr)	222	222
Electric centrifugal chillers (tons)	23,288	23,288
CAPITAL COSTS (MILLION $)		
Natural gas boiler systems	$ 14.5	$ 14.5
Electric centrifugal chiller systems	$ 58.2	$ 58.2
Total	$ 72.7	$ 72.7
OPERATING COSTS		
<u>Operating Cost Factors</u>		
Boiler efficiency (seasonal average)	82%	82%
Electric resistance COP		
Chiller system COP (seasonal average)	4.1	4.1
Labor FTE		
Heating FTE per 1 MMBtu/hr capacity	0.025	0.025
Cooling FTE per 1000 tons of capacity	0.300	0.300
FTE requirements		
Heating	5.6	5.6
Cooling	7.0	7.0
Total	12.5	12.5
Labor rate ($/FTE)	$ 90,000	$ 90,000
Boiler maintenance costs (% of capital)	2%	2%
Electric chiller maintanance costs ($/ton/yr)	$ 30.00	$ 30.00
Cooling make-up water consumption (gal/ton-hr)	$ 2.50	$ 2.50
Water/sewer ($/gal.)	$ 12.19	$ 12.19
Water treatment chemicals ($/gal.)	$ 0.85	$ 0.85

Table 18. Assumptions and Calculations for Self-Generation Estimates

Comparing District Energy Costs to Self-Generation Costs

The generalized costs of each district energy technology scenario were then compared with generalized self-generation costs. Sensitivity analyses were prepared for major input variables including the costs of electricity, financing costs and valuation of GHG emissions. Input variables for each scenario are shown in Table 19.

	District Energy Electricity and Gas Prices			Building Electricity and Gas Prices			
	Purchased Electricity $/kWh)	Sale of Excess Electricity ($/kWh)	Natural Gas ($/MMBtu)	Purchased Electricity $/kWh)	Natural Gas ($/MMBtu)	Weighted Average Cost of Capital	GHG value ($/MTCO2E)
1	$ 0.065	$ 0.050	$ 8.50	$ 0.080	$ 11.00	10.2%	$ -
2	$ 0.090	$ 0.080	$ 8.50	$ 0.135	$ 11.00	10.2%	$ -
3	$ 0.065	$ 0.050	$ 8.50	$ 0.080	$ 11.00	6.4%	$ -
4	$ 0.090	$ 0.080	$ 8.50	$ 0.135	$ 11.00	6.4%	$ -
1CO2	$ 0.065	$ 0.050	$ 8.50	$ 0.080	$ 11.00	10.2%	$ 25
2CO2	$ 0.090	$ 0.080	$ 8.50	$ 0.135	$ 11.00	10.2%	$ 25
3CO2	$ 0.065	$ 0.050	$ 8.50	$ 0.080	$ 11.00	6.4%	$ 25
4CO2	$ 0.090	$ 0.080	$ 8.50	$ 0.135	$ 11.00	6.4%	$ 25

Table 19. Assumptions for Sensitivity Analysis Scenarios for Simplified Economic Comparison of District Energy and Conventional Building Systems

Annual cost saving results are summarized in Figure 20 (assuming zero value for GHG emission reductions) and Figure 21 (assuming a GHG value of $25 per metric ton of carbon dioxide equivalent) when the district energy scenarios are compared with conventional building boilers and chillers. The following discussion is organized around the DES technology scenarios.

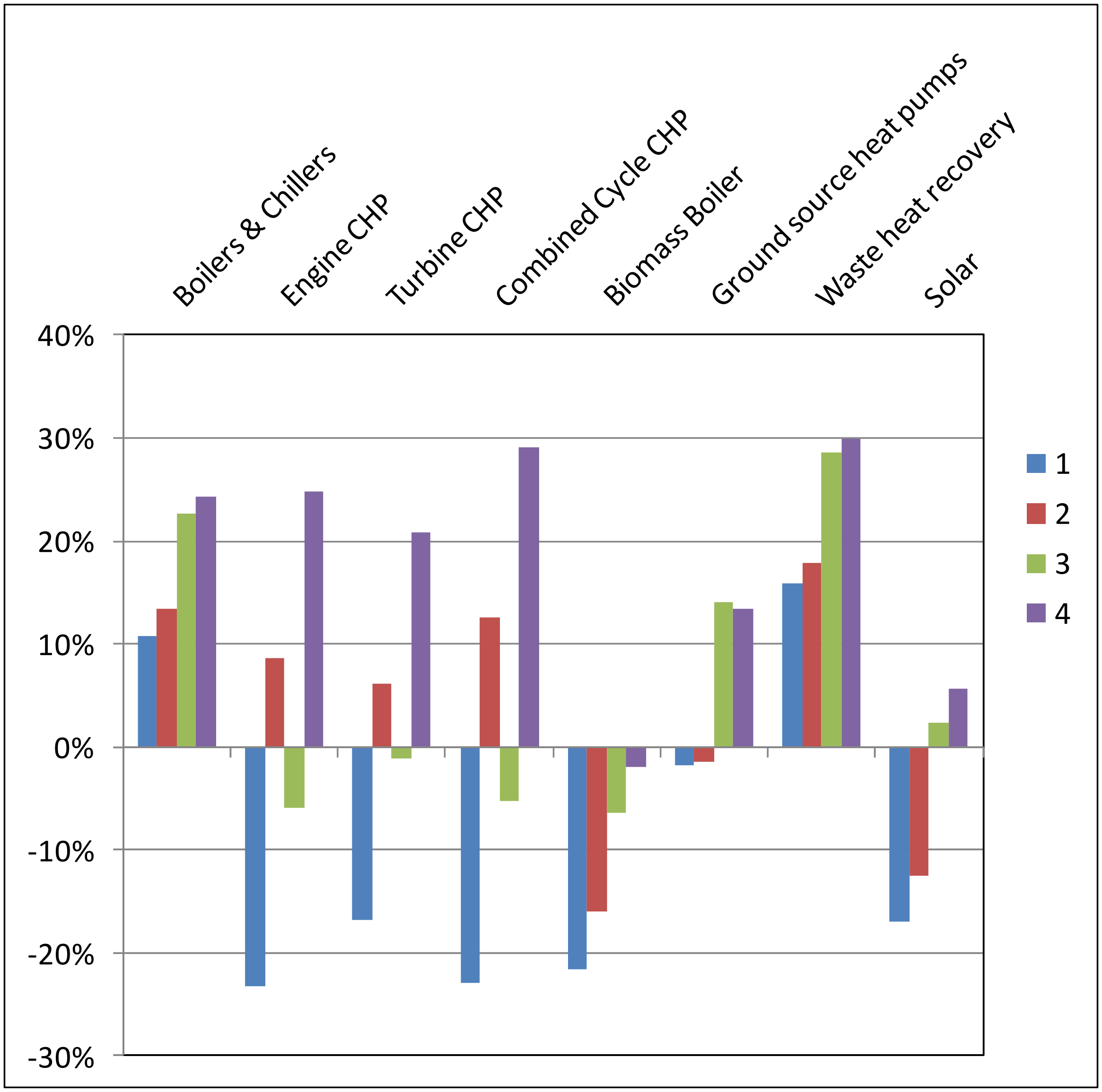


Figure 20. Percentage Total Cost Reduction with District Energy Scenarios Compared with Conventional Boiler and Chiller Building Technologies (With Zero Value for Greenhouse Gas Emission Reductions)

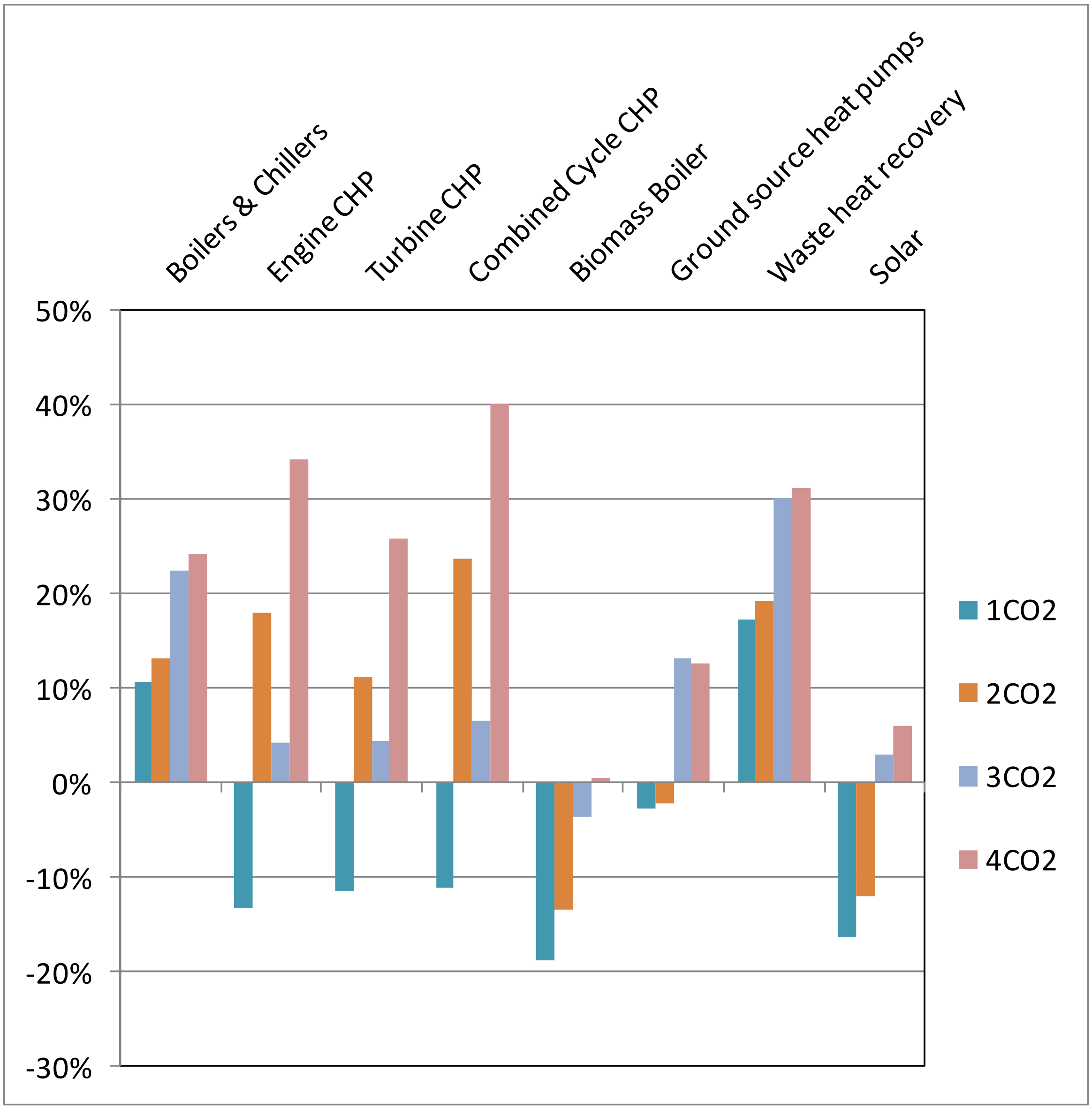


Figure 21. Percentage Total Cost Reduction with District Energy Scenarios Compared with Conventional Boiler and Chiller Building Technologies (With $25 per Metric Ton Value for Greenhouse Gas Emission Reductions)

Natural gas chillers and electric centrifugal chillers

A basic district energy technology configuration (natural gas boilers and electric centrifugal chillers) has a modest 10% cost advantage over conventional building boiler and chiller systems in Scenario 1. Although district energy requires the construction of hot water and chilled water distribution systems, plant capacity can be constructed and operated more cost-effectively with many small boiler and chiller installations. Operating costs benefit from higher volume purchases of natural gas and reduction of electricity costs by cutting peak power demand through thermal energy storage.

Note, however, that this simplified economic analysis is based on the assumption that the entire system is built out immediately and serves the full load immediately. Realistically, build-out of the system and ramp-up of load will occur over time on a case-specific basis, which would reduce the economic advantages of DES.

With higher electricity prices (Scenario 2) there is a modest gain in cost advantage.

Cost of capital has a strong impact on district energy economics. In Scenarios 3 and 4, with lower cost of capital, DES cost savings double to about 20%.

The assumption of a $25 per metric ton value for GHG has very minor impact on the comparative economics because the GHG emissions of this DES technology scenario and the conventional building scenario are quite similar.

CHP and absorption chillers

This discussion combines all 3 CHP technology scenarios (reciprocating engine, simple cycle gas turbine and combined cycle gas turbine). Under base case assumptions (low electricity value, high cost of capital), none of the CHP technology scenarios is cost-effective. With higher electricity prices (Scenario 2), CHP DES provides savings ranging from about 6% to 13%. The assumption of lower cost of capital but the base case electricity cost assumption (Scenario 3), improves the economics compared with Scenario 1 but not enough to achieve cost-effectiveness. When higher electricity values are combined with lower cost of capital (Scenario 4), CHP shows cost savings ranging from about 21% to 29%.

The assumption of a $25 per metric ton value for GHG increases CHP savings significantly because CHP is offsetting power from the grid. The *improvement* in cost savings range from about 5% to 12%. Scenario 3 (low electricity prices and high cost of capital) moves from negative savings to modest savings of about 4% to 7%.

Biomass boiler and absorption chillers

The biomass boiler technology scenario is capital-intensive and is not cost-effective under any of the Scenarios except 4CO2, in which it shows a savings of about 1%.

Ground source heat pumps

This technology scenario is relative capital-intensive and requires significant consumption of electricity. It shows slightly negative savings with high cost of capital (Scenarios 1 and 2) but significant savings of about 13% to 14% with lower cost of capital (Scenarios 3 and 4). The assumption of a $25 per metric ton value for GHG actually reduces the savings because this technology scenario is electricity-intensive.

Waste heat recovery and electric chillers

Under the hypothetical assumptions used, this technology scenario has cost savings ranging from about 16% to over 30%. As noted above, the waste heat is assumed to be located more than 4 miles away from the DES.

Solar heating and electric chillers

This technology scenario is not cost-effective unless low-cost capital is assumed, and then the savings are quite modest (about 2% to 6%).

Power Grid Benefits

District energy systems serve more densely developed areas, which also tend to have high electricity demands. District cooling systems reduce peak power demand through the use of chilled water or ice thermal energy storage, which shift power demand from on-peak to off-peak periods. To the extent that heat-driven chillers are used in the district system (usually in conjunction with CHP), further reduction in peak power demand is provided. Further, district energy CHP facilities generate power in high power load areas, and can be dispatched based on real-time peak power pricing signals. For example, Princeton University cut its peak power demand from 27 MW to 2 MW with a combination of CHP, absorption chillers and thermal energy storage.

Reductions in peak power demand have multiple benefits. Electricity transmission and distribution losses from remote power plants are reduced, and constraints in delivery of power to high-load areas are relieved.

District energy and CHP can also play other useful roles in facilitating increased use of renewable power technologies by helping balance the power grid. As non-dispatchable renewable generation sources (such as wind and solar) increase, there will be greater needs to quickly increase or decrease other generation in response to decreases or increases in renewable power production. This other generation is likely to be relatively inefficient simple cycle gas turbines.

The carbon intensity of gas-fired power plants can be significantly reduced if the resulting waste heat is recovered. Hot water thermal storage can be used to maximize heat recovery by smoothing out the supply of heat relative to demand. Thermal storage through hot water accumulators is a common practice in district heating systems. Accumulators have been successfully deployed to facilitate use of CHP to match fluctuating power demand in a range of applications. The European Union has concluded that there is a good potential for using CHP to back up wind turbines in a spot market for power.

For the district energy scenarios assessed in this study are estimated to significantly reduce peak power demand on the grid, as summarized in Table 20.

	1	2	3	4	5	6	7	8
	Boilers & Chillers	**Engine CHP**	**Turbine CHP**	**Combined Cycle CHP**	**Biomass Boiler**	**Ground source heat pumps**	**Waste heat recovery**	**Solar**
District Energy System (MW)								
Electric centrifugal chiller systems	7.1	5.0	5.0	5.0	5.0	4.5	7.1	7.1
Absorption chiller systems	-	0.9	0.9	0.9	0.9	-	-	-
Heat pump systems	-	-	-	-	-	3.9	-	-
Distribution pumping and plant house	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
CHP	-	(22.5)	(13.4)	(23.5)	-	-	-	-
Total	8.0	(15.7)	(6.6)	(16.7)	6.8	9.2	8.0	8.0
Building Systems (MW)	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7
% Reduction with District Energy	25%	248%	162%	257%	36%	14%	25%	25%

Table 20. Impact of District Energy Scenarios on Net Peak Power Demand

Energy and Environmental Benefits

The direct air emission factors used in the environmental analysis of fuel-consuming district energy systems are summarized in Table 21.

	Emissions in lbs/MMBtu fuel			
	CO2	NOx	SO2	Notes
Natural gas boiler	118	0.0310	0.0006	Low Nox burner with flue gas recirculation
Reciprocating engine	118	0.0257	0.0006	Selective catalytic reduction and catalytic oxidation
Gas turbine	118	0.0138	0.0006	Dry low-NOx combustion
Biomass boiler	0	0.3000	0.0200	Net zero life cycle GHG emission

Table 21. Assumed Air Emission Characteristics of Fuel-Consuming District Energy Technologies

The energy and environmental impacts of each DES scenario are compared with conventional technologies in Table 22. The calculated impacts include primary fossil energy consumption and emissions of GHG, nitrogen oxides (NOx) and sulfur dioxide (SO2). Both direct emissions (associated with fuel consumption at the district energy plant or building) and indirect emissions (associated with power plants to generate and deliver purchased electricity used by the district energy plant or building system). Power grid emissions are based on data from the U.S. Environmental Protection Agency eGRID 2010 Version 1.1 database. The factor used was the average for the two EPA regions covering the COG region.

		1	2	3	4	5	6	7	8
		Boilers & Chillers	**Engine CHP**	**Turbine CHP**	**Combined Cycle CHP**	**Biomass Boiler**	**Ground source heat pumps**	**Waste heat recovery**	**Solar**
Primary energy consumption									
Primary energy consumption factor for power grid	Btuf/kWhe	10,500	10,500	10,500	10,500	10,500	10,500	10,500	10,500
District energy technology primary energy consumption (MMBtu)									
Direct District Energy consumption		339,845	1,335,623	1,118,251	1,442,068	49,319	94,763	150,313	261,846
Power grid		256,223	(1,266,944)	(737,520)	(1,493,840)	215,443	489,447	256,223	256,223
Total		596,068	68,679	380,731	(51,772)	264,762	584,210	406,536	518,069
Building technology primary energy consumption									
Building systems		335,616	335,616	335,616	335,616	335,616	335,616	335,616	335,616
Power grid		254,853	254,853	254,853	254,853	254,853	254,853	254,853	254,853
Total		590,469	590,469	590,469	590,469	590,469	590,469	590,469	590,469
% reduction in primary energy consumption		-1%	88%	36%	109%	55%	1%	31%	12%
Greenhouse gas emissions									
GHG emission factors									
Natural gas	lbs CO2e/MMBtuf	118	118	118	118	118	118	118	118
Power grid	lbs CO2e/MWH	1,827	1,827	1,827	1,827	1,827	1,827	1,827	1,827
Total annual GHG emissions (metric tons CO2-equivalent)									
District Energy System									
Direct		18,195	71,508	59,870	77,207	2,640	5,074	8,048	14,019
Indirect		20,228	(100,022)	(58,225)	(117,935)	17,009	38,641	20,228	20,228
Total		38,423	(28,514)	1,645	(40,728)	19,649	43,714	28,276	34,247
Building systems									
Direct		17,969	17,969	17,969	17,969	17,969	17,969	17,969	17,969
Indirect		20,120	20,120	20,120	20,120	20,120	20,120	20,120	20,120
Total		38,089	38,089	38,089	38,089	38,089	38,089	38,089	38,089
Reduction with District Energy System		(335)	66,602	36,444	78,816	18,439	(5,626)	9,813	3,841
% reduction in GHG with district energy		-1%	175%	96%	207%	48%	-15%	26%	10%
Regulated pollutant emissions (metric tons)									
Carbon dioxide									
District Energy									
Direct		18,195	71,508	59,870	77,207	2,640	5,074	8,048	14,019
Indirect		20,228	(100,022)	(58,225)	(117,935)	17,009	38,641	20,228	20,228
Total		38,423	(28,514)	1,645	(40,728)	19,649	43,714	28,276	34,247
Building Systems									
Direct		17,969	17,969	17,969	17,969	17,969	17,969	17,969	17,969
Indirect		20,120	20,120	20,120	20,120	20,120	20,120	20,120	20,120
Total		38,089	38,089	38,089	38,089	38,089	38,089	38,089	38,089
% reduction with District Energy		-1%	175%	96%	207%	48%	-15%	26%	10%
Nitrogen Oxides									
District Energy									
Direct		4.8	15.7	7.4	9.4	103.7	1.3	2.1	3.7
Indirect		15.3	(75.6)	(44.0)	(89.1)	12.9	29.2	15.3	15.3
Total		20.1	(59.9)	(36.6)	(79.7)	116.5	30.5	17.4	19.0
Building Systems									
Direct		14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
Indirect		15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2
Total		29.2	29.2	29.2	29.2	29.2	29.2	29.2	29.2
% reduction with District Energy		31%	305%	225%	373%	-299%	-5%	40%	35%
Sulfur Dioxide									
District Energy									
Direct		0.1	0.4	0.3	0.4	0.0	0.0	0.0	0.1
Indirect		70.3	(347.7)	(202.4)	(409.9)	59.1	134.3	70.3	70.3
Total		70.4	(347.3)	(202.1)	(409.5)	59.1	134.3	70.4	70.4
Building Systems									
Direct		-	-	-	-	-	-	-	-
Indirect		69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.9
Total		69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.9
% reduction with District Energy		-1%	597%	389%	686%	15%	-92%	-1%	-1%

Table 22. Energy and Environmental Impacts of District Energy Scenarios

Implementation Challenges

DES Challenges

There are a range of challenges which may inhibit the development of district energy systems, including:

Awareness, information and education

Generally, the people and organizations that could be key stakeholders in implementing a DES are not aware of the potential benefits of these systems. Even if city officials, building owners and others are aware of district energy and its benefits, they generally lack the expertise needed to facilitate implementation of these systems. Development of a new DES is a complex undertaking that requires support from many stakeholders including building owners, utilities, city officials, engineers and architects.

Leadership

Development of a new DES involves many institutional, technical, legal and financial issues. Successful implementation requires one or more informed, motivated public-sector ‘champions’ who understand the benefits of a DES and how to successfully guide its implementation and integrate stakeholder interests. Early determination of the most appropriate ownership structure will facilitate timely decisions and actions to advance project development and financing.

Price signals

There are no price signals for the public benefits of DES (in economists’ terms: “positive externalities”) such as lower GHG emissions, infrastructure flexibility, decreased price volatility, improved energy security and local economic benefits of using local resources to meet local needs. Although in some cases a DES can be economically viable based on direct current economics (ignoring externalities), it is often challenging without a wise technical plan for phased implementation, some form of financial support from the public sector, and a concerted information and education program to communicate the long-term economic, environmental and energy security benefits.

Capital costs

The large initial capital investment required is a key constraint to developing a new DES. While district energy is a proven and reliable energy service technology, its benefits are accrued over an extended period. The difficulty is ‘birthing’ the system, given the high initial capital costs and need to obtain sufficient customer commitments to finance the initial investment. Financing the initial feasibility and design studies and the development effort is often a key barrier, since a potential system’s financial viability cannot be evaluated prior to the completion of such studies.

Air emissions permitting[22]

Despite potential regional air quality benefits, development of district energy systems may be hampered by air quality regulations. Our current air quality regulatory system does not always recognize the total environmental benefit of district energy system because it focuses on the central district energy plant emissions without consideration of offset emissions from building-scale combustion source and power plant emission reductions resulting from reduced grid power demand and/or the contribution of CHP power to the grid.

Air quality permitting requirements require a case-by-case analysis based on the type of plant facility, fuels used, the general location relative to current air quality, the specific location relative to dispersion of pollutants, the operating schedule for the facility and other factors.

New and modified sources of air emissions, such as boilers, require permits for construction and operation depending on the type of source (fuel type, emissions level, industry) and the location (whether the region is in attainment or nonattainment of the National Ambient Air Quality Standards (NAAQS)).

NAAQS are set by the EPA, under the authority of the CAA. The NAAQS limit the allowable outdoor concentration of six *criteria pollutants*:

- Carbon monoxide (CO)
- Nitrogen oxides (NO_x)
- Sulfur dioxide (SO_2)
- Particulate matter (PM/PM-10) [23]
- Ozone
- Lead

If a new source of air pollution, or a modification of an existing source is proposed in a way that increases emissions, a new source permit is required or an existing permit must be modified. New Source Review (NSR) is a pre-construction review and permitting program. This program is intended to ensure that new emissions will not degrade air quality in attainment areas (areas that meet NAAQS) or interfere with plans to achieve attainment in non-attainment areas (areas that do not meet NAAQS).

NSR comprises two programs:

- Prevention of Significant Deterioration (PSD), which applies in attainment or unclassifiable areas; and
- Non-Attainment Area (NAA), which applies in non-attainment areas and imposes stricter requirements.

[22] This discussion draws on a range of sources including www.epa.gov and “District Energy Systems: An Analysis of Virginia Law, Prepared for the Northern Virginia Regional Commission by McGuire Woods Consulting”.

[23] EPA groups particle pollution into two categories: "Inhalable coarse particles," such as those found near roadways and dusty industries, are larger than 2.5 micrometers and smaller than 10 micrometers in diameter. "Fine particles," such as those found in smoke and haze, are 2.5 micrometers in diameter and smaller.

Washington D.C. as well as parts of Northern Virginia and Southern Maryland have been designated as a nonattainment areas for ozone, 1 hour (severe); ozone, 8 hour (moderate), and PM 2.5.

For a given project, PSD may be applicable for one pollutant and NAA may be applicable for another pollutant.

Sources are defined as major or minor, as defined and discussed below. Both major and minor sources must obtain a permit. The following discussion focuses on major source permitting.

New major sources and modified major sources in attainment areas must use Best Available Control Technology (BACT) and in non-attainment areas must use Lowest Achievable Emission Rate (LAER). Major source permitting requires the application of BACT controls for non-attainment areas, Lowest Achievable Emission Rate (LAER) controls for attainment areas, and an ambient air impact analysis. BACT is determined on a case-by-case basis and is defined for each subject pollutant as an emissions limitation based on the maximum degree of reduction that is achievable taking into account energy, environmental, and economic impacts and other costs. LAER is defined similarly except that economic impacts cannot be considered.

In addition, in non-attainment areas new sources must offset their emissions by purchasing emission reduction credits from existing sources that agree to reduce emissions by an amount greater than the emissions from the new source.

Facilities with emissions below major source thresholds, but above exemption levels, are subject to “minor” NSR permitting. A source with the potential to be a major source may be permitted as a minor source if it has permit conditions that effectively limit emissions to minor source levels (“synthetic minors”) and avoid permitting as a major source.[24]

Regulations provide certain exemptions for new and modified sources.[25] Additionally, sources with emissions below certain levels are exempt from new source review.[26]

In addition to the NSR pre-construction permitting program, facilities may also be subject to a Title V Federal Operating Permit or a State Operating Permit. Major sources subject to Title V include those that emit 100 tons per year of any criteria pollutant; or 10 tons per year of a single

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[24] For district systems using biomass, the State Air Pollution Control Board has issued a general permit for Minor New Source Review for biomass pilot projects. 9VAC5-520-10 et seq. Such projects must be new sources, must not be an incinerator, and must qualify as a minor source. Additionally, such projects must generate no more than the energy equivalent of 5MW of electricity, generate solely from biomass, and such energy must be sold to an unrelated person, a stationary source, or used in a manufacturing process. Certain testing requirements and conditions apply.

[25] 9VAC5-80-1320. Exemptions include external combustion fuel burning equipment units (not engines and turbines) using one of the following: solid fuel with a maximum heat input of less than 1,000,000 Btu per hour; liquid fuel with max heat input less than 10,000,000 Btu per hour; liquid and gaseous fuel with a max heat input less than 10,000,000 Btu per hour; or gaseous fuel with a max heat input of less than 50,000,000 Btu per hour.

[26] Pollutant Exemption Levels in “potential to emit” (tons per year) for New Sources are as follows: Carbon Monoxide 100; Nitrogen Oxides 40; Sulfur Dioxide 40; Particulate Matter 25; Particulate Matter (PM10) 15; and Volatile organic compounds 25.

hazardous air pollutant or 25 tons per year of all hazardous air pollutants. State Operating Permits may contain the emission limiting conditions necessary to create a synthetic minor source from a potentially major source.

Land use

DES work best in densely developed areas with a mix of building uses. However, North American land use development patterns – and plans and regulations governing them – do not always encourage the high thermal densities or mixed-use patterns most conducive to DES.

Lack of integrated planning

When the issues of new power plant capacity, solid waste management, environmental quality, local economic development and other critical issues are approached through integrated community energy planning, the benefits of a DES become more visible. However, decisions about these issues are generally not made in an integrated fashion in North America.

Siting

While new district energy distribution technologies can economically and efficiently transport energy over greater distances than previously possible, a DES plant must still be sited relatively close to potential users that are usually located within a densely developed area. Power plant siting processes are generally still oriented toward large centralized plants far from population centers, despite the fact that new plant technologies are far smaller and cleaner than in the past. In addition, siting can raise crippling 'not-in-my- backyard' problems.

Grid access

The overall increase in competitive pressure in power generation has both positive and negative impacts on district energy. Increasing competition will intensify the pressure to wring as much marketable energy as possible out of power plants, thereby making more valuable the 'thermal sinks' that a DES represents. On the other hand, increasing competitive pressure may make it more difficult to establish new CHP systems because of their capital-intensiveness and the time lag before these systems achieve sufficient growth to realize their full economic benefits. In an era of increasing competition in electric generation, power plant investment time frames may tend to shrink, making it more difficult to substitute capital for energy through a DES or other energy systems with high capital costs and low fuel costs.

Key Stages in System Development

Development of a DES requires interactive progress on a range of fronts, including:

- Market assessment
- Stakeholder communication
- Technical design
- Economic analysis
- Securing the revenue stream with customer contracts
- Permitting

- Financial structuring and analysis

These multiple aspects are interrelated, with progress on one aspect enabling other elements to move forward. For example:

- The recommended technical design depends on a sufficient market, economic feasibility and stakeholder support.
- The financial feasibility of the system depends on the technical design, capital and operating costs and the financial structure.
- The investment and financing path depends on the ownership structure and key contractual relationships.
- The cost of capital depends on the strength of contractual commitments for a revenue stream.
- Contracts for revenue flow depend on the economics of the system as well as a communication/education process to help customers and other stakeholders understand the full benefits of the system, including flexibility for managing long-term risks.

The bottom line is that there is inevitably an iterative nature to the process of creating a DES.

Stakeholder Assessment

A critical early step is to identify key stakeholders and assess stakeholder interests. It is important that early in the process the issues important to these stakeholders are identified and clearly understood. An effective education and community relations strategy should be developed and carefully implemented.

Market Assessment

DES planning must start with a solid foundation of load analysis. A realistic load projection must be established so that sufficient capacity is planned but the system is not overbuilt or the revenues overestimated. This assessment must examine both new and existing development plans and schedules, developing a breakdown of the potential customer base in the study area by building space projection, building type/usage, and development phasing. Peak demands, daily and seasonal load patterns and annual energy must be evaluated, then mapped in order to plan and size the distribution systems.

It is also important to determine the likely "Business As Usual" scenario so that the costs and benefits of the DES can be compared with the conventional approach.

Screening Analysis

The screening analysis requires several steps. First, a site-specific inventory and mapping of current and future renewable or waste heat energy sources available to the community is conducted. Then a range of technologies for producing usable energy from the potential energy sources are identified and evaluated. The screening analysis typically addresses:

- Technical reliability
- Energy efficiency
- Water efficiency

- Environmental impacts including greenhouse gases and criteria pollutants
- Capital costs
- Operating costs

Economic and Financial Analysis

Interactive with development of the system conceptual design is an economic analysis, which typically includes:

a. Capital costs including soft costs.
b. Estimated annual operation & maintenance (O&M) costs, including but not limited to, system maintenance, management and staff, insurance (property and liability), property taxes, municipal fees, customer service costs, land rent, overheads and fuel costs.
c. Annual costs including capital amortization.

At the feasibility study stage, the rate structures and rate levels based on the cost of service and financial performance criteria should be developed.

As the technical concept and financial structure are developed, a financial proforma model must be developed, including the following elements:

- Customer Loads
- Capital Costs
- Depreciation
- Operation and Maintenance Costs
- Labor Costs
- Debt Service
- Rates and Revenues
- Cash Flow
- Net Income
- Internal Rate of Return

Environmental Benefits

Key environmental benefits should be quantified, including impacts on emissions of GHG, regulated pollutants and ozone-destroying refrigerants. This analysis should assess both the direct emissions at the district energy plant or building as well as the indirect emissions from the power plants generating power purchased by the DES or building.

To the extent possible, it is desirable to assess the potential employment impacts including not only the jobs directly created (e.g., construction workers) but also those indirectly created in the industries or services that support the project (e.g., workers in factories providing equipment and supplies). In addition, there are induced jobs created when the workers employed directly or indirectly spend their wages for such things as groceries, transportation, etc.

Permitting

Timely initiative of permit applications and successful follow-up are critical to timely initiation and completion of system construction. Air permitting is discussed above under DES Challenges.

Risk Analysis

A thorough risk analysis should be conducted to inform the assessment of options for ownership and operations. Development of a DES is a relatively capital-intensive undertaking. Further, capital costs are "front-loaded" because of the high costs of installing basic plant infrastructure and pipe mains in the early years – in contrast to adding customers in later years with relatively short, small-diameter pipe additions and the installation of additional chillers in the plant. Given these characteristics, a fundamental risk in development of a DES is lower-than-projected customer load. This may be due to a low level of success in marketing to targeted customers, or as a result of slower-than-projected build-out of projected development.

Incremental Development of a DES

An incremental approach to development of a DES can be the key to successful implementation. By starting with an anchor load (or multiple anchors, depending on geography) small networks are generally easier to finance and implement, with the potential to grow out and ultimately be integrated into a broader system.

Ownership and Operation Models

Key Considerations

There are many different types of entities that may seek to play an ownership and/or operational role in a DES, including local governments, universities, private for-profit companies and private non-profit companies. A district energy system's ownership and operating structure can be as critical to its success as its engineering and design. Ownership structures will have a significant impact on the options available for funding and financing the development of the system.

As discussed in an associated report for the COG,[27] ownership of the DES affects the extent and type of regulation as a public utility.

There are many different models of ownership and operation with no single preferred model; the ultimate structure should be tailored to the goals of the major stakeholders. Key considerations in the assessment of models should include:

- Access to a range of project financing sources, including state and federal grants, tax credits, subsidized financing tools and cost-effective market-based financing.
- Risk mitigation in construction and operation of the system that can address energy costs and price stability, as well as changing environmental parameters.
- Flexibility to accommodate future expansions of the DES while supporting development and sustainability agenda.

The question of what type of entity should own and operate a DES begins with the understanding that there are several component parts to a DES, the ownership and operation of which may be separated and undertaken by different entities. In fact, ownership of the underlying assets can also be separated from the day-to-day operation of the DES. The two components of the district system that are potentially separable for purposes of ownership and operation include:

- Generation in the form of thermal energy that is the source for providing district heating and cooling; and
- Distribution of heating and cooling services from the point of the thermal source to the point of interconnection with the district energy user, typically in the form of piping below the public street right-of-way.

For example, it would be possible for one or more private entities to own and operate the plant systems and provide thermal energy under contract to a district energy piping system that is owned by a public agency or a public-private partnership.

[27] "Technical Support for Integrated Community Energy Solutions Task 1: Integrating Energy into Local Regulations and Programs," FVB Energy Inc. Dec. 2011.

Range of Ownership Options

The best way to think of the options for system ownership and operation is as a range with a purely private system of ownership and operation at one end and a fully publicly owned and operated system at the other end of this continuum. A purely private system is typically most applicable where all of the property that is part of the DES is under one owner, such as a college campus or large hospital complex.

Another element of the ownership analysis is whether the ownership is structured as a not-for-profit corporation, a for-profit entity, or a joint venture that includes both for-profit and non-profit partners. Within the for-profit categories, there are also several options include a limited liability corporation, or an entity based on a cooperative utility model.

The potential participants in an ownership structure may include a the local power or natural gas utility company, a company specializing in DES ownership and operations, the local government, building owners in service area, or individuals or institutions that provide project equity in exchange for access to federal tax credits or the tax benefits of accelerated equipment depreciation and net operating loss deductions.

What follows is a brief description of some of the more common business structures based on a review of the literature and some examples of other district energy system in the U.S. and Canada.

Private utility model

Most multi-user district energy systems in the U.S. are owned and operated by private companies, either as stand-alone entities, or as subsidiaries of larger utility companies. In some cases, cities have sold off or privatized their district energy systems as a means to raise funds. The private utility model tends to be the case with larger district energy systems in larger communities such as Philadelphia, Detroit, Indianapolis, Seattle and somewhat smaller cities such as Omaha and Hartford.

Private non-profit

This approach has been used to great success in St. Paul, Minnesota. Based on positive results from feasibility studies funded by the federal and state governments in the late 1970s, a private non-profit corporation was created to develop a new hot water district heating system. Its initial board of directors included representatives of building owners, the City of St. Paul and the local electric utility, which had for decades provided district heating service via an aging district steam system. The initial project cost, including construction, financing and other expenses (not including building conversions) was $45.6 million in 1982 dollars. Funding sources included tax exempt revenue bonds and loans from the City of St. Paul and Housing and Urban Development (HUD) funds. The City played a vital role in helping the system in the early years by deferring payment of franchise fees until the young utility company reached a certain threshold of financial viability on its balance sheet. In 1992 a district chilled water system was developed to help customers respond to the phase-out of CFC refrigerants. The City played an important role in obtaining low-cost loans for construction of the system. In 2003, the district heating and cooling company partnered with Cinergy, a private utility company, to finance a 25 MW biomass CHP facility.

City-owned non-profit

Motivated by concerns about power grid reliability and its impact on economic development, the Town of Markham, Ontario developed a DES to serve a major new development area. The Town decided to finance, own and operate the system itself in a new non-profit entity called Markham District Energy. As noted above, the system delivers hot water and chilled water to local customers and, through CHP, provides electricity to the power grid. The system began operating in 2001 and is now undergoing it fourth stage of expansion. Based on its sole ownership, the City also operates it, has a direct role in marketing district energy services to additional users, and is able to coordinate expansion of the energy system with other public infrastructure projects.

City-owned, privately contracted

Metro Nashville District Energy System was built in 2004 to replace a waste-to-energy facility that had been in operation for 30 years but was destroyed by fire. The City of Nashville owns the facility but contracted for design and construction of a new DES plant and operation of the DES with Constellation Energy Source, a private energy services company. Constellation manages metering, invoicing of customers, operations and maintenance of the facility as part of a 15-year operating agreement with the City. The new facility was built using tax-exempt municipal bonds that had no cost to taxpayers because the bond payments are made entirely from revenues from energy sales. The DES boilers and chillers use gas and electricity to provide district heating and cooling for about 50 buildings in the downtown business district.

Conclusions

District energy systems lay the groundwork for flexible community energy solutions that recover and distribute community energy sources including power generation waste heat, other waste heat sources, renewable thermal energy and ground source energy. Based on this analysis, a range of community energy technologies have the potential to save energy, reduce GHG emissions, cut peak power demand and save money in the COG region.

The generalized economic analysis concludes that:

- District energy natural gas boilers, electric chillers and thermal storage (typically the initial step in developing a DES) can provide modest cost advantages over conventional hydronic building technologies, especially if low-cost financing is available.
- CHP is not cost-competitive where electricity is inexpensive but can be cost-effective in areas with high power costs if the excess electricity not needed by the district energy plant can be sold to the grid, especially if low-cost capital is available.
- The assumption of a $25 per metric ton carbon dioxide equivalent value for GHG significantly improves the cost savings with CHP.
- Biomass is not cost-effective at the scale of DES modeled.
- Ground source heat pumps are modestly cost-effective if low-cost capital is available.
- Solar district heating is unlikely to be cost-effective.
- Waste heat recovery is potentially very cost-effective but truly requires a site-specific analysis.

The impact of DES varies depending on the particular scenario, but generally provides significant reductions in total fossil fuel consumption, GHG and regulated pollutants. These calculations include both direct consumption by the district energy plant or the building system and indirect consumption in the power grid resulting from electricity purchased from the grid. GHG reductions range from minor (about 2%) for DES natural gas boilers and electric chillers to highly significant (from about 60% to over 165%) for CHP.

District energy provides significant reductions in peak grid power demand, generally in excess of 25% compared with conventional approaches. With CHP, the peak power demand reduction ranges from 160% to 260%, as the CHP facility, which is sized based on the heating load, makes a large net contribution to the grid during the summer.

Development of a DES can be a significant undertaking, requiring an interactive progress on a range of fronts, including: market assessment; stakeholder communication; technical design; economic analysis; air emissions permitting; securing the revenue stream with customer contracts; permitting; risk analysis; and financial structuring and analysis. As noted above, an incremental approach to development of a DES can be the key to successful implementation.

Ownership structures have a significant impact on the options available for funding and financing the development of the system. There are many different models of ownership and operation with no single preferred model; the ultimate structure should be tailored to the goals of the major stakeholders. Key considerations in the assessment of models should include:

- Access to a range of project financing sources, including state and federal grants, tax credits, subsidized financing tools and cost-effective market-based financing.
- Risk mitigation in construction and operation of the system that can address energy costs and price stability, as well as changing environmental parameters.
- Flexibility to accommodate future expansions of the district energy system while supporting development and sustainability agenda.