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Business Case for a Micro-Combined Heat and Power Fuel-Cell System in Commercial Applications

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October 2013

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U.S. Department of Energy
Energy Efficiency and Renewable Energy
Office of Fuel Cell Technology

Pacific Northwest National Laboratory
Richland, Washington 99352

Executive Summary

Combined heat and power fuel cell systems (CHP-FCSs) provide consistent electrical power and hot water with greater efficiency and lower emissions than alternative sources. These systems can be used either as baseload, grid-connected, or as off-the-grid power sources. This report presents a business case for CHP-FCSs in the range of 5 to 50 kWe. Systems in this power range are considered "micro"-CHP-FCS. For this particular business case, commercial applications rather than residential or industrial are targeted. To understand the benefits of implementing a micro-CHP-FCS, the characteristics that determine their competitive advantage must first be identified. Locations with high electricity prices and low natural-gas prices are ideal locations for micro-CHP-FCSs. Fortunately, these high "spark spread" locations are generally in the northeastern area of the United States and California where government incentives are already in place to offset the current high cost of the micro-CHP-FCSs. As a result of the inherently high efficiency of a fuel cell and their ability to use the waste heat that is generated as a CHP, they have higher efficiency. This results in lower fuel costs than comparable alternative small-scale power systems (e.g., microturbines and reciprocating engines).

A variety of markets should consider micro-CHP-FCSs including those that require both heat and baseload electricity throughout the year. In addition, the reliable power of micro-CHP-FCSs could be beneficial to markets where electrical outages are especially frequent or costly. Greenhouse gas emission levels from micro-CHP-FCSs are 69% lower, and the human health costs are 99.9% lower, than those attributed to conventional coal-fired power plants. As a result, FCSs can allow a company to advertise as environmentally conscious and provide a bottom-line sales advantage. As a new technology in the early stages of adoption, micro-CHP-FCSs are currently more expensive than alternative technologies. As the technology gains a foothold in its target markets and demand increases, the costs will decline in response to improved manufacturing efficiencies, similar to trends seen with other technologies. Transparency Market Research forecasts suggest that the CHP-FCS market will grow at a compound annual growth rate of greater than 27% over the next 5 years. These production level increases, coupled with the expected low price of natural gas, indicate the economic payback period will move to less than 5 years over the course of the next 5 years.

To better understand the benefits of micro-CHP-FCSs, the U.S. Department of Energy worked with ClearEdge Power to install fifteen 5-kWe fuel cells in the commercial markets of California and Oregon. Pacific Northwest National Laboratory is evaluating these systems in terms of economics, operations, and their environmental impact in real-world applications. As expected, the economic analysis has indicated that the high capital cost of the micro-CHP-FCSs results in a longer payback period than typically is acceptable for all but early-adopter market segments. However, a payback period of less than 3 years may be expected as increased production and research and development breakthroughs bring system cost down, and CHP incentives are maintained or improved.

Acknowledgments

The authors would like to acknowledge Peter Devlin of the U.S. Department of Energy Office of Energy Efficiency and Energy Renewal, Fuel Cell Technology Office, for his support and direction. The authors also would like to acknowledge reviews provided by representatives from industry: Tom Prevish and David Anderson at ClearEdge Power, Sandra Saathoff and Joe Blanchard at ReliOn, and Anthony Leo at Fuel Cell Energy.

Acronyms and Abbreviations

°C	degrees Celsius
AEO	Annual Energy Outlook
BOP	balance-of-plant (as in balance-of-plant components in a system)
CHP	combined heat and power
CO	carbon monoxide
CO_2	carbon dioxide
dB	decibel
DOE	U.S. Department of Energy
FCS	fuel cell system
HHV	higher heating value
HTPEM fuel cell	high-temperature polymer electrolyte membrane (fuel cell)
kW	kilowatt
kWe	kilowatts electrical
kW-hr	kilowatt-hour
kWt	kilowatts thermal
LCC	life-cycle cost
LHV	lower heating value
MW	megawatt
MMBtu	million British thermal units
NO_x	nitrogen oxides
O&M	operating and maintenance
PEM	proton exchange membrane
PBI	polybenzimidazole
PM	particulate matter
RFF	Resources for the Future
scf	standard cubic foot
SOFC	Solid Oxide Fuel Cell
SO_x	sulfur oxides
VOC	volatile organic compounds

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1.0 Introduction and Objective

A fuel cell directly converts fuels (e.g., hydrogen, natural gas, or methanol) into electricity by reacting it electrochemically with an oxidizer (e.g., oxygen or air). Unlike batteries, which will eventually discharge and require recharging or replacement, as long as fuel and an oxidizer are provided to a fuel cell, it will continue to provide power. Fuel cells are much more efficient than small power generation systems that rely on combustion. For example, a typical internal combustion engine for a car operates at 28 to 30% efficiency, while a fuel cell generally operates at 30 to 50% efficiency. Heat that is generated and not converted to electricity can be used as part of a combined heat and power fuel cell system (CHP-FCS). When this heat is used, the efficiency of a CHP-FCS can nearly double, reaching efficiency levels of 60 to 90%.

Fuel cells have been developed based on several different technologies and are generally described by the technology used for their electrolyte. Some of the typical fuel cell systems that are readily available in today's market place include 200 W to 500 kW low-temperature polymer electrolyte membrane (PEM) units (Reli-On, Ballard), 1.5 kWe solid oxide fuel cell (SOFC) units (Ceramic Fuel Cells Limited), 5 kWe PBI-based high-temperature PEM units (ClearEdge Inc.), 100 kWe to 400 kWe SOFC systems (Bloom Energy Inc.), 200 kWe to 400 kWe phosphoric acid FC units (United Technologies Inc.), and 300 kWe to 3 MWe molten carbonate FC system (Fuel Cell Energy Inc.) [1.1-1.7]. While this is not an all-inclusive list of the marketplace, it provides an idea of the power range and type of fuel cells available.

This business case will specifically address electricity demands between 5 and 50 kWe. This electrical output range considered is what is called micro-CHP-FCS. Although there is a growing market for residential fuel cells, this work targets the light-commercial buildings/business segment. It will address micro-CHP-FCS in the United States both today and in the future as fuel cell technologies improve and the market changes. Its purpose is to assist potential future adopters in understanding the key factors affecting the economics of micro-CHP-FCS use, possible markets that would benefit from their use and their anticipated growth as the market changes and fuel cell technologies are improved.

As a means of evaluating the market, both building simulants and actual micro-CHP-FCS installations were evaluated. For modeling these systems, EnergyPlus simulation software was used to determine the electrical and heat usage throughout the year in a variety of locations. This modeling was used to identify the locations and applications that are best suited for micro-CHP-FCS. For the actual micro-CHP-FCS evaluation, the U.S. Department of Energy (DOE) funded a pilot program to install and demonstrate high-temperature PEM (PBI) fuel cells micro-CHP-FCS arrays within light-commercial buildings. The results of this demonstration will be used as a case study for better evaluating the current market and identifying areas needing improvement to increase micro-CHP-FCS market viability. Although the case study utilized only one type of fuel cell available in today's market place, the results should be representative of the general trends typical of other micro-CHP-FCSs available in that range.

2.0 Drivers for Micro-CHP FSC Implementation

There are two types of drivers for micro-CHP-FCS installation: the hard benefits that can be quantified financially and the ancillary benefits that impact marketability. The hard benefits are “spark spread,” system efficiency, grid reliability, and government incentives and regulations. These will be discussed in Sections 2.1 to 2.4. The ancillary benefits include such things as environmental and operational advantages. These benefits will be discussed in Section 2.5.

2.1 High Spark Spread

A micro-CHP-FCS should be installed where the cost of electricity is relatively high and cost of natural gas is relatively low. High electricity costs provide a justification for the additional costs required to install and operate a distributed power source such as a micro-CHP-FCS rather than use power from the grid. Figure 2.1 depicts the geographic distribution of electricity prices throughout different regions in the United States. This graphic, which is based on data from the U.S. Energy Information Administration (EIA) data, indicates that the cost of electricity is generally high in the Northeast, California, and the noncontiguous states of Alaska and Hawaii. The price of electricity is low in the Northwest and Southeast.

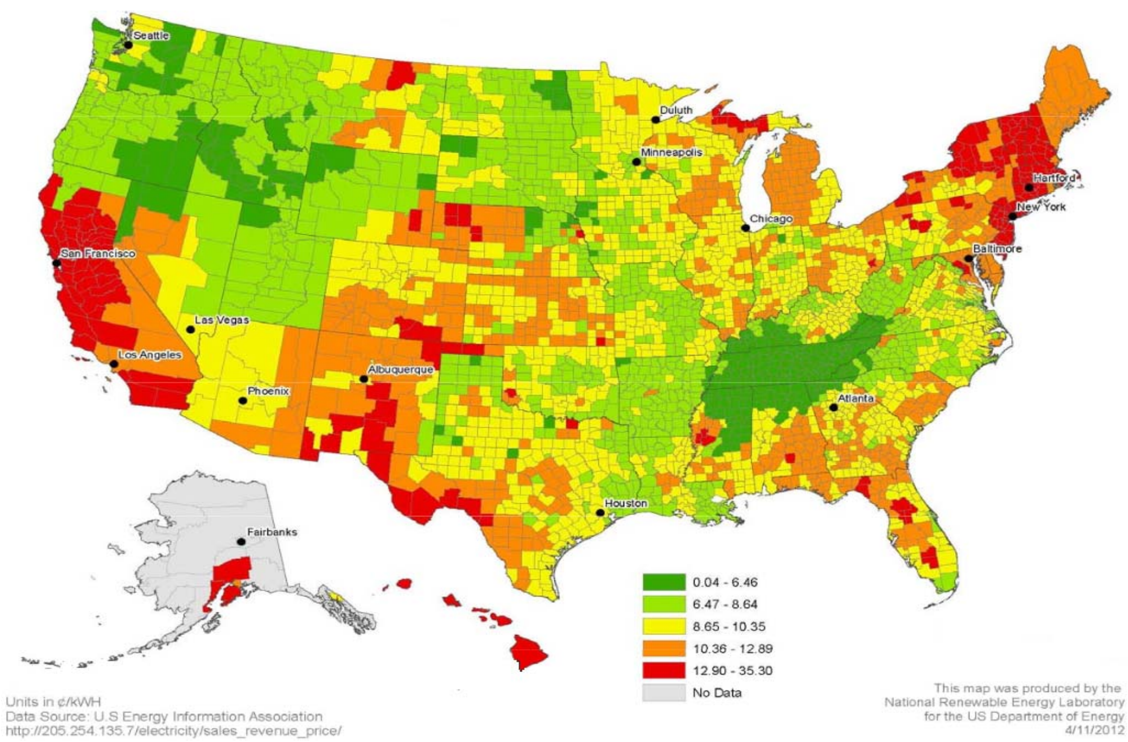

Figure 2.1. Electricity Prices in the United States (¢/kWh). Sources: Graphic -- National Renewable Energy Laboratory;[1] data basis for the graphic -- EIA [2.3].

[1] Graphic accessed and downloaded by PNNL staff from the National Renewable Energy Laboratory website on April 4, 2013; however, the graphic is no longer accessible.

In addition to a high cost of electricity, the business case for a micro-CHP-FCS is improved if the cost of its fuel is low. This business case assumes that the micro-CHP-FCS operates using natural gas. Figure 2.2 depicts the geographic variation in natural-gas prices across different regions in the United States. As can be seen from the figure, those areas with high electrical costs do not necessarily correspond to the areas with high natural-gas costs. Unlike electrical costs, which have seen a slow but steady increase over the last decade, natural-gas prices have dropped to the lowest level in nearly a decade, and have declined every year for the last 5 years [2.1]. Although gas prices are expected to moderate upwards in coming years, prices will remain relatively low, improving the business case for FCSs.

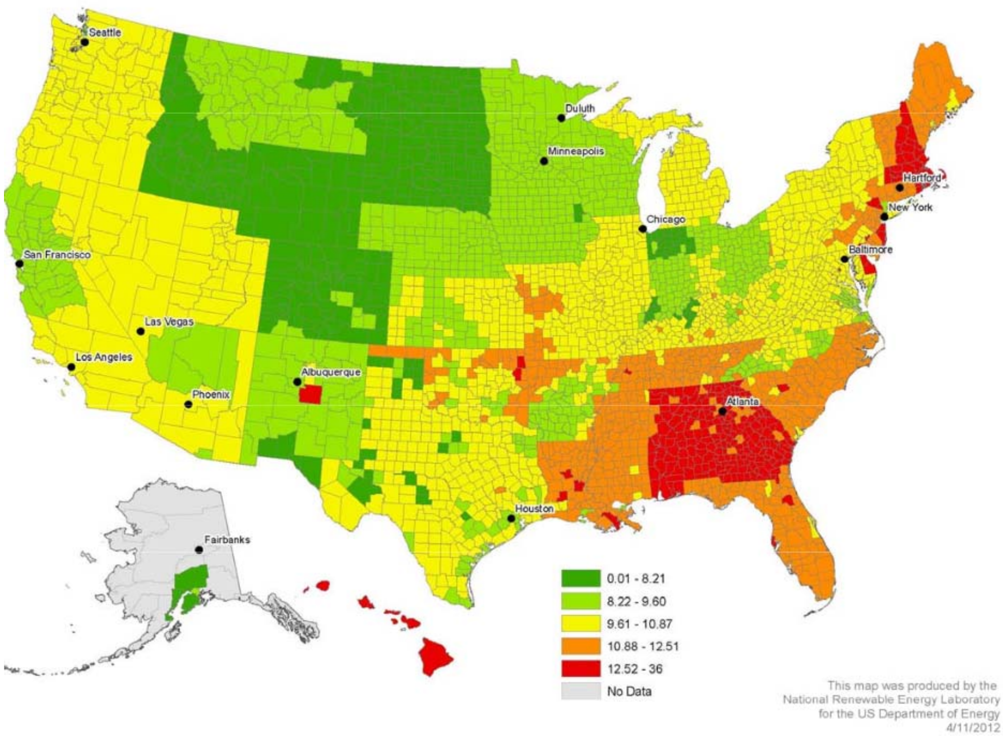

Figure 2.2. Prices of Natural Gas in the United States ($/MMBtu). Sources: Graphic -- National Renewable Energy Laboratory;[1] data basis for the graphic -- EIA [2.4].

The difference between the cost of electricity and natural gas is called the "spark spread" and the profitability of employing a micro-CHP-FCS is improved with a higher "spark spread." Spark spread is a common metric used to estimate the cost effectiveness of a power plant by showing the difference between the electricity price and the price of the natural gas needed to produce that electricity. The spark spread is the amount of saving achieved by a gas-fired generator for not having to purchase electricity from the grid and the cost of the natural gas needed to produce that much electricity. It is calculated using the following equation:

$$\text{Spark spread } = \text{power price } - (\text{natural} - \text{gas price }/(\text{efficiency}))$$

[1] Graphic accessed and downloaded by PNNL staff from the National Renewable Energy Laboratory website on April 4, 2013; however, the graphic is no longer accessible.

For a power generation technology to be cost effective, it must 1) have a positive spark spread that 2) is higher than the levelized cost-per-kWh. These criteria will ensure that the cost savings from using the micro-CHP-FCS will pay off all of its capital costs.

The spark spread is a metric to determine the profitability of gas-fired electric generators with minimum input available. It is a quick analysis of the market conditions of power generation, but there are limitations on it use. It considers only the cost of electricity and fuel and does not take into consideration other costs associated with the generation of electricity, such as capital cost, taxes and operation and maintenance (O&M) costs. [1] A more complete analysis that includes life-cycle cost (LCC) and payback period will be described later in Section 3.

Four cities representing likely implementation sites were selected for evaluation in this business case: Chicago, San Francisco, New York City, and Boston. These particular cities were chosen in an effort to find locations with high anticipated heating loads, high spark spread, favorable government incentives, and databases available for their analysis. The spark spreads for these cities, based on current and future electricity and gas prices [2.2], are shown in in Figure 2.3. Energy (i.e., natural gas and electricity) prices for previous years (2009 to 2013) for each city were found from the literature, utility rate structures, and a Bureau of Labor Statistics database [2.2]. Year-by-year rate of change in energy prices in the future were calculated based on EIA's *Annual Energy Outlook (AEO) 2012*. These rates of change were then applied to city specific energy prices to forecast energy price in each city from 2014 to2020. A higher heating value (HHV) electrical efficiency of 36% was used to calculate this spark spread.[2] This figure demonstrates the wide range of spark spread values across this list of cities and in comparison to the national average. The decrease in spark spread after 2015 is the result of a larger nationally forecasted increase in natural-gas prices relative to electricity prices.

2.2 Utilization of Heat Generated

The spark spread described in Section 2.1, accounts only for the fuel cell's electrical generation. Micro-CHP-FCSs also provide heat as a usable byproduct. As a result, if the particular application can also use the heat that is generated, the energy savings is further improved over just the fuel cell's high electrical efficiency manifested in the spark spread.

For a typical CHP-FCS, the ratio of usable heat to electricity produced is nearly 1:1. As a result, both power and heat savings can be realized within the spark spread calculation. Under these conditions and for the current cost of natural gas, the value of a modified spark spread including heat generation would further increase by between $0.03 and 0.05/kWh from the values shown in Figure **2.3**.

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[1] See http://www.eia.gov/todayinenergy/includes/lnk.cfm?lnk=/todayinenergy/includes/SparkSpread_Explain.htm

[2] All equipment manufacturers quote heat rates in terms of the lower heating value (LHV) of the fuel. On the other hand, the usable energy content of fuels typically is measured on an HHV basis. In addition, electric utilities measure power plant heat rates in terms of HHV. For natural gas, the average heat content of natural gas is 1030 Btu/scf on an HHV basis and 930 Btu/scf on an LHV basis, a difference of approximately10%. (Taken from http://www.epa.gov/chp/documents/catalog_chptech_full.pdf)

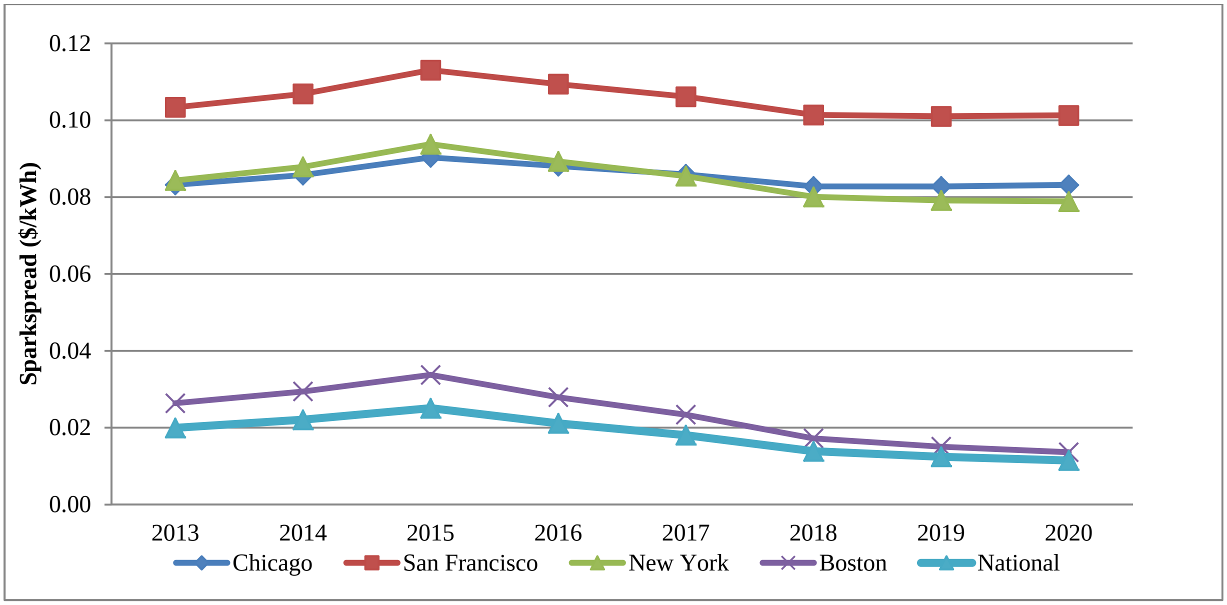

Figure 2.3. Estimated Spark Spread over the Next 7 Years in Chicago, San Francisco, New York City, and Boston assuming a Fuel Cell with 36% Efficiency (HHV). Source: Calculation based on current and future electricity and gas prices [2.2].

To benefit from the higher system efficiency of the CHP and realize this larger spark spread, steady heat usage is required. Such usage would include both continuous heating requirements over the course of a day and throughout the year. As shown in Figure 2.4, the market that uses the largest fraction of hot water relative to electricity throughout the year is lodging (e.g., hotels, dormitories, etc.) [2.5]. Facilities that provide lodging require hot water for swimming pools and hot tubs, laundries, kitchens, and bathrooms. Inpatient healthcare facilities have the next largest ratio of hot water to electricity usage (e.g., small hospitals, nursing homes, etc.). In addition to high water heating to electrical usage, these types of facilities operate 24 hours-a-day, which leads to higher continuous hot water usage. Similar to hotels and hospitals with their high energy usage, multifamily residential buildings are alternative candidates for micro-CHP-FCSs based on their large hot water and space-heating demands.

For this analysis, several building types—a small office building, a small hotel, a small hospital, a quick-service restaurant, a small school, and an apartment building—were simulated using DOE's EnergyPlus simulation software [2.19]. Space-heating and service-water heating demand data and electricity demand were extracted over 1 hour time intervals for the course of the year. These data were used to examine the portion of the building heating demand that could potentially be served by a micro-CHP-FCS based on temperature limitations and the quantity of thermal energy it supplied. Details of this analysis and its results are shown in Appendices A and B, respectively.

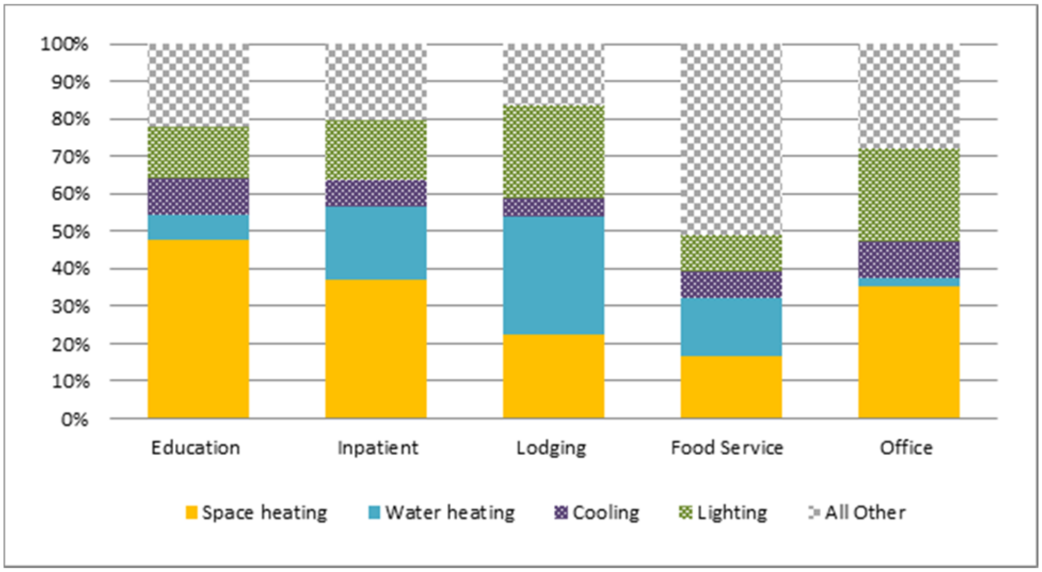

Figure 2.4. Water-Heating-Intensive Market Segments. Source: U.S. Energy Information Administration (EIA). 2003 [2.5]

A sample result of these simulations is shown in Figure **2.5**. The plot shows the demand for service-water heating throughout 1 year at a small hotel in Boston. The micro-CHP-FCS provides 22 kW of base thermal load while the excess is supplied by an alternative source. In this case, a large fraction of the total heat output generated by the FCS is used by the hotel. Although electrical use is not shown, it also has 100% usage by most facilities analyzed. Based on this modeling, a small hotel, hospital, and apartment building would be able to provide a high fraction of the service water required while wasting very little heat and would be the best applications for a micro-CHP-FCS. This is especially the case for cities in the northeastern United States. A small office, quick-service restaurant, and school tend to have less favorable heat utilization.

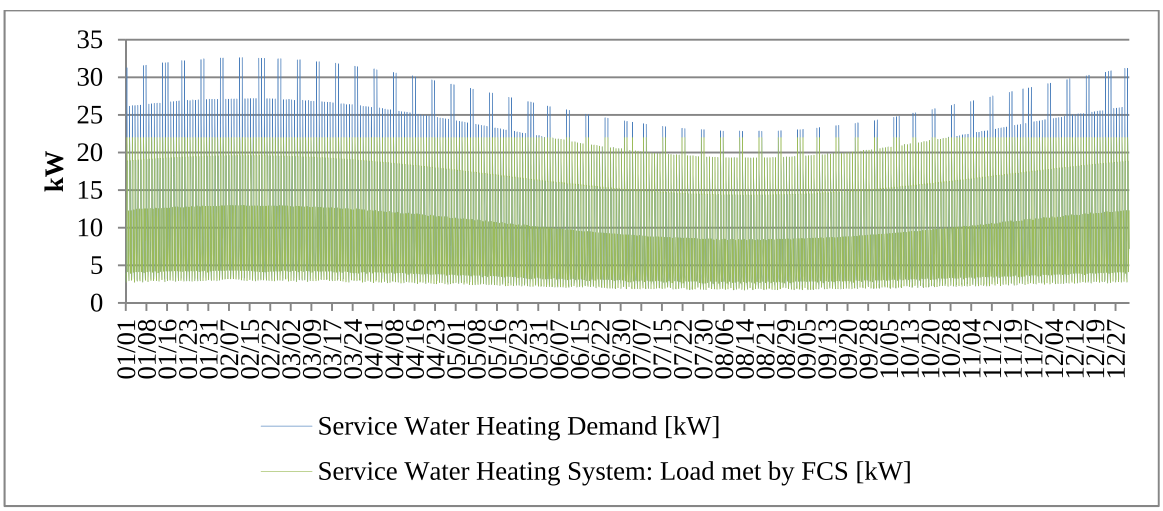

Figure 2.5. Annual Profile for Service-Water Heating Demand for a Small Hotel in Boston with the Thermal Demand Met by an FCS with 22 kW of Thermal Output. Source: Data obtained from an EnergyPlus annual simulation of the DOE commercial reference building model of a small hotel [2.19].

2.3 Grid Independence

A significant advantage of fuel cells is they offer constant power production that is independent of the electrical grid. Electrical outages can be costly, and as a result, there are numerous markets that appear promising for fuel cell power as an alternative to grid power. An average of 500,000 people are affected by power outages in the United States each day,[1] and, the annual cost of these outages is estimated to be approximately $119 billion.[2] Statistics show that 80 to 90% of power failures originate at the distribution level [2.6]. In 2009, the utility grid was given a D+ grade (continuously descending) by the American Council of Civil Engineers [2.7]. At the same time, electrical loads that the power grid supplies to sophisticated equipment, such as computers, high-speed digital processors, and electronic components, are more sensitive than ever to power fluctuations and outages than less sophisticated loads such as light bulbs, refrigerators, and water heaters. As a result, many companies that rely on these power-sensitive components for their operations and communications are actively seeking alternatives/augmentation to the grid.

Estimating the annual cost of outages for a facility can help them determine damages that could be avoided by installation of micro-CHP-FCS. An example of how to quantify the cost of facility disruptions due to both momentary and long-term outages is shown in Table 2.1. According to references discussed in Appendix C, the cost of an outage per hour for a building with 100 kWh load is between $4000-6800/hr. The table shows that as little as five outages at the lower value of $4000/hr can result in $12,000 in annual losses. These costs should be considered with respect to the micro-CHP fuel cell system business case.

Table 2.1. Estimated Annual Cost of Outages for a Small Commercial Building[1]

Outage Type	Outage Duration	Facility Disruption per Outage	Number of Outages per Year	Total Annual Facility Disruption	Outage Cost per Hour	Total Annual Costs
Momentary Interruptions	5.3 Seconds	15 Minutes	4	1 Hour	$4,000	$4,000
Long-Duration Interruptions	1 Hour	2 Hours	1	2 Hours	$4,000	$8,000
Total			**5**	**3 Hours**		**$12,000**

[1]The bases of the calculations used to develop this table are provided in Appendix C.

2.4 Government Incentives and Taxes

Government incentives are designed to support penetration into the market by new technologies that have societal benefits (e.g., environmental benefits) when the costs are not yet economic for the consumer. There are different types of incentives designed to encourage deployment of both distributed generation systems generally and FCS specifically in the United States (e.g., corporate tax credits, federal grant programs, federal loan programs, etc.). This section presents available federal incentives along with

[1] http://www.cnn.com/2010/TECH/innovation/08/09/smart.grid/index.html.
[2] These data were disclosed by CNN Tech in 2010 based on information from University of Minnesota, Transmission & Distribution World, DOE, and EIA.

local, state, and utility incentives and policies offered in selected states. Table 2.2 summarizes federal incentives/policies available in the form of a corporate tax credit.[1]

Table 2.2. Federal Incentives/Policies for 2013

Incentive Type:	Corporate Tax Credit
Amount:	The credit is equal to 30% of expenditures.
Maximum Incentive:	$1,500 per 0.5 kW
Eligible System Size:	0.5 kW or greater
Equipment Requirements:	A minimum capacity of 0.5 kW that have an electricity-only generation efficiency of 30% or higher.

In addition to federal incentives, a variety of state incentives are available.

Table 2.3 shows a comparison of different types of policies and incentives available in northeastern states, California, and Illinois. As shown, California, New York, New Jersey, and Massachusetts have a variety of incentives and policies available in addition to the federal incentives [2.8].

Table 2.3. Types of State Incentives Applicable to Commercial CHP for 2013

Policy/ Incentive Type	CA	NY	NJ	MA	NH	CT	VT	ME	IL
Feed-in Tariff	✓								
Grant		✓	✓	✓	✓			✓	✓
Loan	✓	✓	✓	✓	✓	✓	✓		
Production Incentive		✓	✓	✓				✓	
Rebate	✓	✓	✓	✓	✓				
Tax	✓	✓	✓	✓		✓	✓		
Utility Rate	✓	✓	✓			✓			

2.5 Ancillary Benefits

2.5.1 Environmental Benefits of Clean Power

The micro-CHP-FCS system was compared to a conventional coal-fired power plant, an average gas-fired plant, and an advanced cogeneration plant in terms of the levels of greenhouse gases produced. The emission factors of the coal-fired plant, natural-gas power plant, and advanced natural-gas cogeneration are from [2.9, 2.10], and the emission factor of the micro-CHP-FCS is provided by the system supplier. As can be seen in Table 2.4, a micro-CHP-FCS can produce as little as one-third the emissions of a conventional energy system composed of a coal-fired power plant and one-half the emissions of an average natural-gas-fired plant assuming that they produce the same quantity of electricity.

[1] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F.

Table 2.4. Green House Gas Mitigation Production Comparison

	CO_2 Equivalent (g/kW-hr)
Case 1: Coal-Fired Plant	1696
Case 2: Natural-Gas Plant	1188
Case 3: Cogeneration System	602
Case 4: Micro-CHP-FCS	528

The exhaust gas composition from a micro-CHP-FCS also was analyzed to quantify the change in air pollution emissions as compared to the same cases discussed in Table 2.4 [2.9,2.10]. The exhaust constituents used for analysis are carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM), sulfur oxides (SO_x), and volatile organic compounds (VOC). Air pollution emissions data is quantified by calculating the change in human health costs from the release and uptake of these emissions [2.11]. For all cases, the human health costs were calculated assuming that the only the electric generation system being analyzed was used to produce all electricity in the United States. This relative comparison is shown in Table 2.5. These costs decrease significantly when switching from a conventional system to a micro-CHP-FCS system. For example, the total human health costs resulting from air pollution from electricity production in the United States based on the use of average conventional generation systems as compared to micro-CHP-FCSs differ by a factor of 886.

Table 2.5. Human Health Cost Comparison of CHP-FCS and Other Energy Generators Based on Air Pollution Emissions

	Carbon Monoxide (CO)	Nitrogen Oxides (NO_x)	Particulate Matter (PM)	Sulfur Oxides (SOx)	Volatile Organic Compounds (VOC)	Relative Human Health Costs per Year
	Metric tonnes/kW-hr					
Case 1: Conventional Coal-Fired Plant[(a)]	1.200E-07	2.000E-06	2.000 E-07	1.000E-06	1.300E-08	886
Case 2: Natural-Gas Powered Plan[(b)]	1.220E-07	1.406E-06	1.776 E-07	1.093E-06	1.329E-08	851
Case 3: Advanced NG Cogeneration System[(a)]	3.300E-07	7.000E-07	7.400E-09	2.700E-07	1.600E-08	256
Case 4: micro-CHP-FCS[(c)]	1.711E-08	6.900E-09	0	0	0	1

(a) Reference [2.9].
(b) Reference [2.10].
(c) Provided by the system supplier.

2.5.2 Future Environmental Tax

Market and policy observers generally agree that some form of future carbon tax (tax on CO_2 emissions) can be expected in the United States. This tax will target emissions from fossil fuel combustion, most typically exemplified in transportation and fossil-fuel-fired electricity generating plants. One outcome of imposing such a tax likely would be a noticeable increase in electricity prices as utilities pass the effects of the tax on to their customers. For this business case analysis, we relied on a recent study by Resources for the Future [2.14], which examines the potential impact of varying tax rates on national electricity rates. The analysis suggests that the imposition of a $25 per ton carbon tax would increase national average electricity rates by 18 to 20% in 2030 compared to baseline rates from EIA's *2011 Annual Energy Outlook* [2.12]. Micro-CHP-FCS electricity rates would be much less than this due to their reduced production of greenhouse gases (See Table 2.4) and their higher efficiency.

2.5.3 Fuel Cells and Other Renewable Sources

Renewable power sources have significant challenges that can be addressed by augmenting their output with a fuel cell. Renewables such as wind, hydroelectric, and solar have varying availability of their energy sources. Hydroelectric and geothermal sources are especially location dependent and are not readily available everywhere. Furthermore, many of these renewable sources do not have the capability to load-follow, and may also generate power when it is not needed. Fuel cells can be used as a baseload resource to supplement the otherwise unpredictable and inconsistent power supply of renewable energy sources.

Fuel cells can be powered by hydrogen generated from biomass from renewable sources such as livestock farming, wastewater treatment facilities, landfills, breweries, and wineries. The hydrogen also can be generated from non-renewable sources such as natural-gas-, propane-, or other petroleum-based processes. This provides wider flexibility and high power source availability while still minimizing the environmental impact.

2.5.4 Benefits of Near-Silent Operation

Fuel cell-based micro-CHPs have the advantage of being quieter than other competing technologies. Reciprocating engines and turbines have moving parts while the fuel cell itself has none. The only components that move would be such things as pumps to supply water and fans to supply intake air and remove excess heat. As a result, fuel cells have an estimated noise value of 60 dB at 1 meter [2.15]. This is the same level as normal conversation. A microturbine, in contrast, has a noise level of 65 dB at 10 meters from the source or 85 dB at 1 meter away (earplugs recommended at this level) [2.16].

2.5.5 Marketing Advantages

Installation of fuel cells or other such approaches have been used by companies advertising themselves as environmentally conscientious and can help differentiate a business from its competitors. In other cases, they may help rehabilitate the poor environmental reputation of a company. Results have shown that the public relations benefit is usually much stronger when the green energy producer is enjoying a "first-mover advantage," in which the company is among the first in its region or industry to buy environmentally friendly energy [2.17].

According to Roper ASW's 2002 Green Gauge study, 30% of Americans closely follow the environmental records of large companies [2.18]. This segment is sometimes referred to as the "lifestyles of health and sustainability" market, estimated to be worth $230 billion in the United States. Companies that have significant lifestyles of health and sustainability market share would be good candidates for micro-CHP fuel cells. This market has increased in recent years to cover a wide range of consumer products and services.

3.0 Micro-CHP Fuel Cell System Economics

The economics of a micro-CHP-FCS is discussed in this section as it compares to other competing technologies. A case study also is provided to better understand the current market and to identify areas that need to be improved to increase micro-CHP-FCS market viability. Finally, an evaluation of the most challenging aspect of fuel cell implementation (i.e., its capital cost) will be discussed in the framework of ways it can be reduced and forecasts of its future direction.

3.1 Comparison to Other CHP Technologies

This study considered three alternatives to the micro-CHP-FCS technology and evaluated the cost effectiveness of each. These alternatives included diesel engines, natural-gas engines, and natural-gas microturbines. Specific details of the alternatives as well as the micro-CHP-FCS such as system cost and fuel usage were developed largely based on the U.S. Environmental Protection Agency's *Catalog of CHP Technologies* [3.1]. The comparison analysis is developed based on generic applications of micro-CHP-FCS technology in the commercial sector and is intended to illustrate relative comparisons.

The alternatives were evaluated under a baseload operating regime. Given that micro fuel cell performance is optimal when operated as a baseload resource, the alternatives were assumed to be operating at a capacity factor of 95%. The systems evaluated were sized to be comparable with an array of five 5-kWe CHP fuel cells operated together to provide 25 kWe of service. Commercially available alternatives included a 50-kWe natural-gas reciprocating engine, a 30-kWe gas microturbine, and a 25 kWe diesel compression engine. Note that diesel generators are not economical to operate for CHP purposes at prevailing diesel costs and the expected operating regime of the FCS, although they are better suited to part loads or intermittent use, as opposed to operating in baseload mode. Further description of the approach taken in this comparison to other CHP technologies is provided in Appendix D.

The results in Table 3.1 demonstrate that the FCS array is roughly 22 to 33% more fuel efficient than close alternatives. Each of these technologies is being continuously improved to be more fuel efficient; thus, the relative comparison should remain somewhat stable. Table 3.1 shows that micro-CHP-FCS are more cost effective to operate than the alternatives for a typical small commercial site as evidenced by the annual savings value. The "Savings Value" shown in this table is a refined value similar to the spark spread discussed in Section 2.1 except it includes heat and electrical savings and O&M costs. Based on this analysis, the values presented in the table suggest favorable economics on average in the specific cities studied. The spark spread for other cities throughout the nation will vary according to local commercial electric and gas rates. As a result, the prevailing economic conditions of a proposed location should be examined individually as part of a business case prior to installation.

Table 3.1. Average Financial Impacts of Operating Alternative Small CHP Systems[1]

CHP System Type	Gas Engine	Microturbine	Micro Fuel Cell
CHP System Capacity, kW	50	30	25
Fuel Use MMBtu/hr	0.6000	0.4220	0.2354
CHP System Fuel Cost $/MMBtu	7.43	7.43	7.43
Electric Price $/kWh	0.1696	0.1696	0.1696
CHP Installed Cost, $/kW	2210	2970	9100
CHP O&M Cost, $/kWh	0.022	0.030	0.035
Availability	0.95	0.95	0.95
Electricity Costs Avoided $/yr	70,560	42,336	35,280
Heat Costs Avoided $/yr	13,554	13,569	9,849
Gas Costs+O&M incurred $/yr	46,262	33,589	21,842
Annual Savings $/yr	37,852	22,316	23,287
Savings Value $/kWh	0.0910	0.0894	0.1119
Simple Payback, yr	2.92	3.99	9.77

Note: Assumes fuel prices averaged for San Francisco, Chicago, New York, and Boston. Potential government incentives are not factored into these estimates.

Figure 3.1 illustrates comparisons of simple payback periods for the viable alternatives. Figure 3.2 shows the relative differences in the average value of energy saved among CHP alternatives. Both of these figures are based on data calculated for Table 3.1 as described in Appendix D. The relatively long payback periods for micro-CHP-FCSs reflect relatively high capital costs because of the newness of the technology. Micro-CHP-FCSs show higher estimated average savings per kWh due to generally higher fuel efficiency.

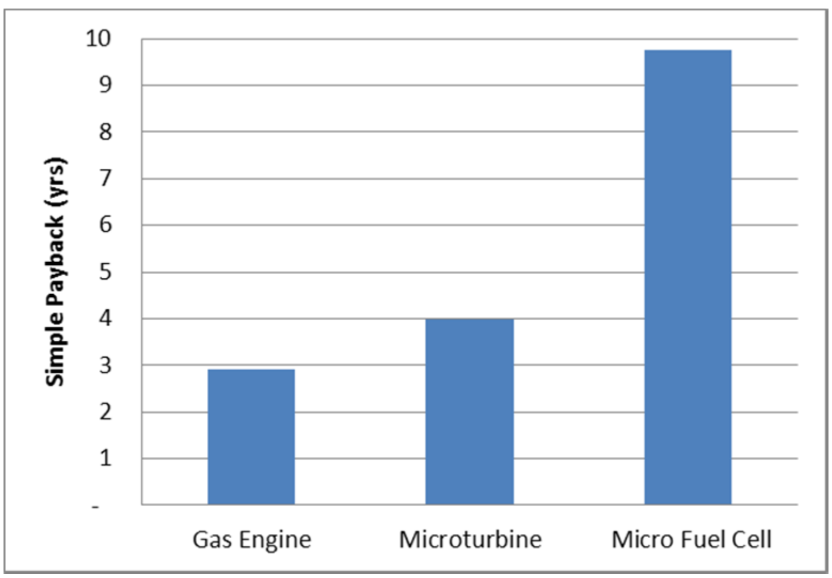

Figure 3.1. Simple Payback Period for Alternative CHP Technologies

[1] The simple payback estimates in Table 3.1 are specific to the particular example micro-CHP systems presented in the EPA CHP Catalog, and thus would differ from values estimated for the specific case-study installations in Section 3.2.

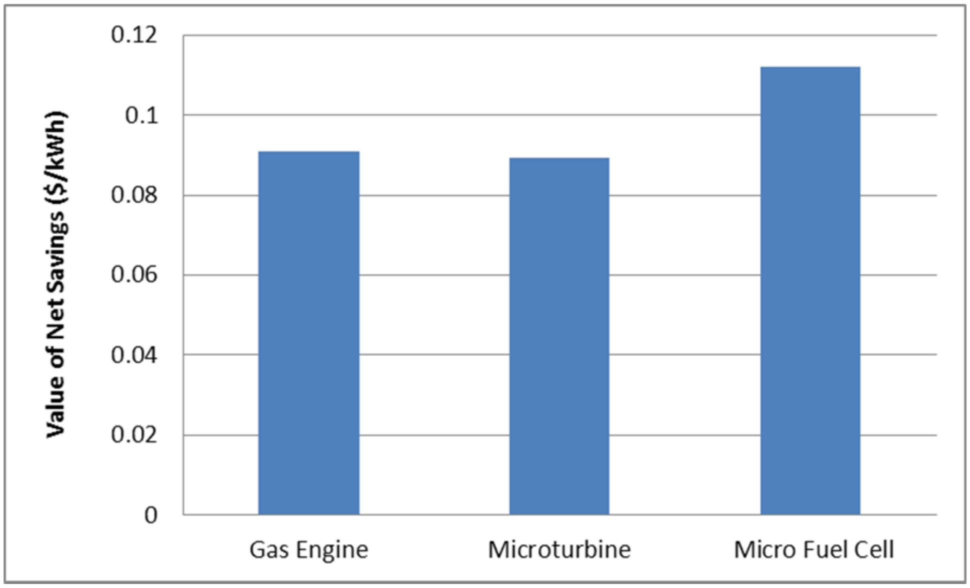

Figure 3.2. Average Net Savings Value for Alternative CHP Technologies

3.2 Micro-CHP-FCS Case Study

One way to understand the economics of micro-CHP-FCS technology is to evaluate systems currently in operation. Between September 2011 and March 2012, ClearEdge Power installed 15 of their micro-CHP-FCSs for application and demonstration at four different deployment sites: two sites in Northern California, one site in Southern California, and one site in Oregon. The detailed case study findings are presented in Appendix E. Although the case study involved only one type of fuel cell available in today's marketplace, the results should be representative of the general trends typical of other micro-CHP-FCSs available in that range.

The LCC analysis described in Section 3.1 compared competing CHP technologies based on generic U.S. Environmental Protection Agency values for each technology. The LCC analysis performed in this section is based on the details of specific micro-CHP-FCS deployments. Additionally, the LCC described in this section has been expanded beyond that performed previously to include upfront O&M costs as part of the capital costs and depreciation as part of the annual savings. This approach, although more complicated, is more typical of that used for FCSs and provides a more realistic value for payback. As with simple payback, this calculation divides the total costs by annual savings.[1] The payback time with and without government incentives is provided in Table 3.2. Detailed calculations are shown in Appendix E.

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[1] The total cost includes capital cost of the equipment, 5-year fuel costs in present day dollars, installation costs, additional equipment costs, decommissioning costs, and sales tax. The fuel cost is a variable cost and is incurred over the period of performance (5 years), and decommissioning cost is a one-time cost that will be incurred at the end of the period of performance. Because the period of performance for the deployed FCS units is 5 years, a 5-year warranty cost is incurred at the time of purchase and installation. The O&M costs are covered by the warranty, including providing analysis data of the fuel cell performance, technical support, and any needed repairs, are aggregated in the capital cost. The detailed breakout of these costs is business sensitive. All costs are recorded in present day dollars. The annual savings includes grid electricity and heating costs. Depreciation included in the annual savings is calculated using a straight-line approach, over 5 years, with a residual value of zero dollars. The depreciation tax rate was assumed to be 33%.

The payback period varied from 4.95 years to 8.66 years when government incentives were excluded from the LCC analysis. The payback period improved to 3.75 years to 4.06 years when incentives were included. Note that the “college” used in the analysis is not eligible for incentives because of the financial nature and location of this organization. Because of its higher installation cost and its location (i.e., Oregon) with much lower electricity costs, the “college” site also has a much higher payback period than the other sites. The payback period values calculated using this analysis are significantly improved over those developed in Table 3.1 because of the depreciation in the calculation. It should be noted that any commercial interest will perform its own analysis of payback period. This analysis is provided here only as an example.

Figure 3.3 shows the average payback period for the current and projected costs (next 5 years) of micro-CHP-FCS units. The average payback periods for the current and projected costs are 6.09 and 4.71 years respectively, assuming there are no incentives. A previous study predicted that the cost of 5 kW stationary PEM fuel cells would decrease by 32% by increasing the production of systems from 100/year to 10,000/year [3.2]. The projected costs for the case study-specific deployments of micro-CHP-FCSs, based on an estimated production of 4000 systems/year [3.3], represent a 25% cost decrease and are very close to the results presented in the previous study [3.2].

Table 3.2. LCC Analysis for 5-Year Period of Performance

Site	Array Size (units)	LCC Cost ($/5kW unit)	Payback (Without Incentives) (years)	Payback, (With Incentives) (years)
College	2	$94K	8.66	8.66
Nursery	3	$76K	4.95	3.75
Recreation	5	$82K	5.32	4.06
Grocery	5	$85K	5.43	3.99
Average		**$84K**	**6.09**	**5.12**

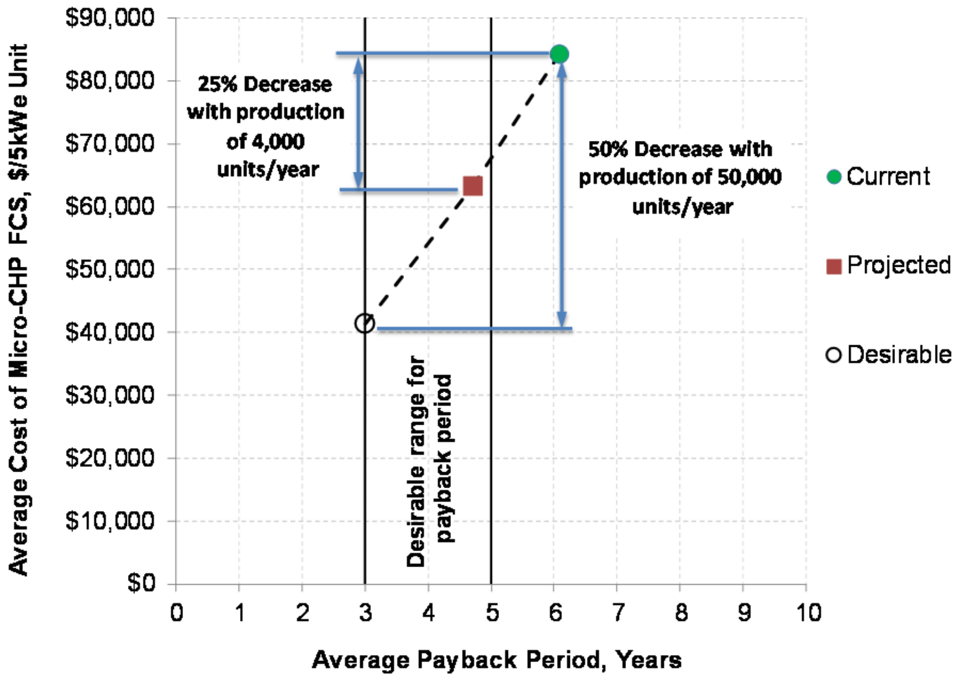

Figure 3.3. Average Payback Period Versus Average Cost of the Micro-CHP-FCS Unit

The average cost of micro-CHP-FCS units also was calculated for a desired payback period of 3 years and is also shown in Figure 3.3. For a desired payback period of 3 years, average cost of micro-CHP-FCS units should be on the order of $41,000 to $45,000, which represents a 50% decrease when compared to today's costs. Detailed calculations are shown in Appendix E. Based on the expected cost reduction as a function of system production, this decrease can be achieved by increasing system production to more than 50,000 units/year [3.2].

3.3 Current and Future Fuel Cell Capital Cost

As can be seen in the previous sections, the primary drawback for the fuel cell is its cost. This reflects the developing nature of the technology. Micro-CHP-FCS technology is not fully mature; thus, as it becomes more widely adopted, costs will decline. The typical costs of fuel cells can be broadly classified into the following four categories:

1. Stack materials cost
2. Cost of balance-of-plant (BOP) systems
3. Stack manufacturing cost
4. Cost of system assembly, testing, and conditioning.

The stack materials consist of the electrodes, electrolyte, flow plates, and catalyst. The stack materials are the most expensive part of the micro-CHP-FCS for most types of fuel cells. The high cost of the platinum catalyst and the high quality assurance requirements on the membrane drive the cost of the lower-temperature fuel cells (low and high-temperature PEM, phosphoric acid). For the higher-temperature fuel cells, the cost is driven by the cells themselves and the seals and separator plates. The BOP systems consist of reactors, burners, humidifiers, blowers, pumps, filters, flow meters, power electronics, and the control system. While no one component in the BOP system is particularly expensive, the large number of components required and their need to be durable result in high costs. Stack manufacturing costs remain relatively high as a result of the need to ensure that there are no imperfections or leaks. The final cost is that of system assembly, testing, and conditioning. Each fuel cell system is hand-assembled and then tested prior to deployment.

The key to driving down costs to truly competitive levels is primarily large-volume manufacturing (thousands of systems, in the near term). System costs are forced downward as engineering experience is gained. The decrease in costs for FCSs has been shown to be a function of the number of units produced [3.4, 3.5].

To estimate the expected growth of the CHP-FCS market to determine the increased level of manufacturing expected in the upcoming years, a forecast was provided in a customized report purchased from Transparency Market Research. Transparency Market Research is a market intelligence company that provides global market research reports [3.6]. They combine quantitative forecasting and trends analysis to provide insights into the future of certain markets.

The commercial CHP fuel cell market (which includes all types of fuel cells—molten carbonate, phosphoric acid, solid oxide, PEM, and alkaline) was estimated to be 23.9 MW in 2011, and it is expected to reach 153.0 MW by 2018, growing at an even higher compound annual growth rate of 27.2% from 2013 to 2018 as compared to the CHP market in general (see Figure 3.4) [3.6].

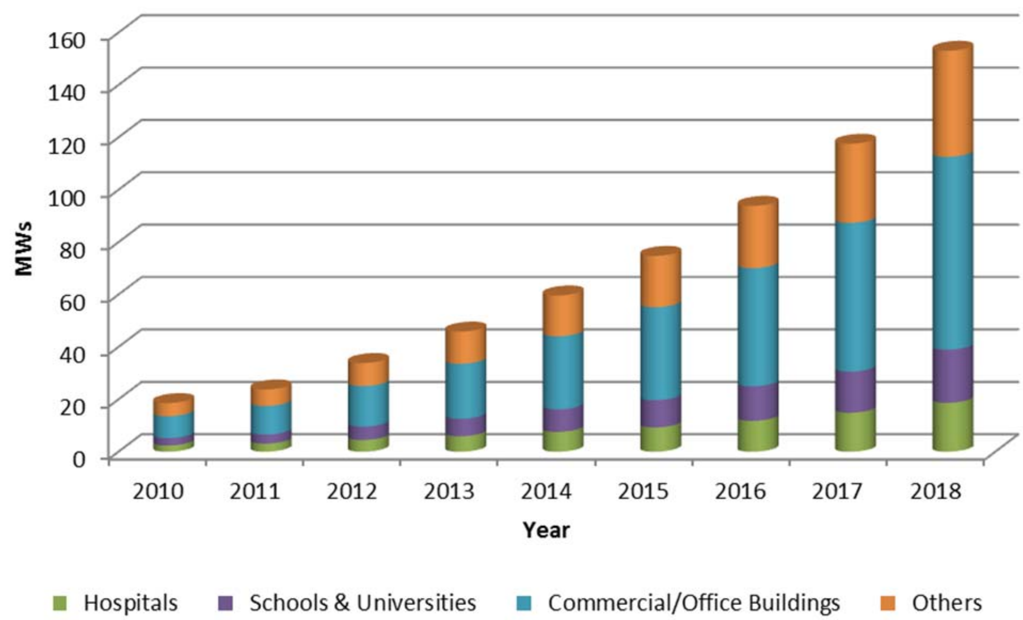

Figure 3.4. Anticipated Growth of Stationary Fuel Cell-based CHP Commercial Market [3.6]

As a means of estimating the system cost reduction with the increased growth of the market, Figure 3.5 illustrates the capital and installation costs of different types of CHP-FCSs from different manufacturers as a function of their global installed capacity [3.7]. Higher global installed capacities are associated with increased mass production levels. The figure shows costs for typical CHP-FCS units (i.e., from Bloom Energy Inc., Ceramic Fuel Cells Limited, ClearEdge Inc., Fuel Cell Energy Inc., JX Oil & Energy, Panasonic, Toshiba, and United Technologies Inc.) available in today's marketplace. Cost information of these typical units is acquired from open sources (i.e., company websites, literature reviews, etc.). However, individual companies are not associated with their respective costs as they could not be verified. Nonetheless, it is clear that the products with a higher global installed capacity generally have lower capital and installed costs. Figure 3.5 also shows the current and projected costs of ClearEdge Power units. The projected ClearEdge costs are based on estimated production of 4000 systems per year (which is based on expected sales). Costs of units from other companies, with similar production levels, can be expected to decrease by the same order.

Based on increased installed power capacity and reduction in cost shown in Figure 3.5, the costs for the entire range of CHP-FCSs are projected to decline by as much as 50% by 2018. This result is consistent with other analyses by others and referenced in this document [3.8]. If the predicted growth increase and subsequent system cost decline are realized, CHP-FCs can become cost competitive in a wider range of markets.

Economies of scale will drive down the cost of the fuel cells further in the future, and as of the date of this publication, there is extensive ongoing research to improve durability, reduce cost, extend the operating range, and identify new materials for fuel cell electrolytes, electrodes, catalysts, seals, fuel processors, and BOP components [3.9]. This development work should also further reduce fuel cell system costs and improve their marketability.

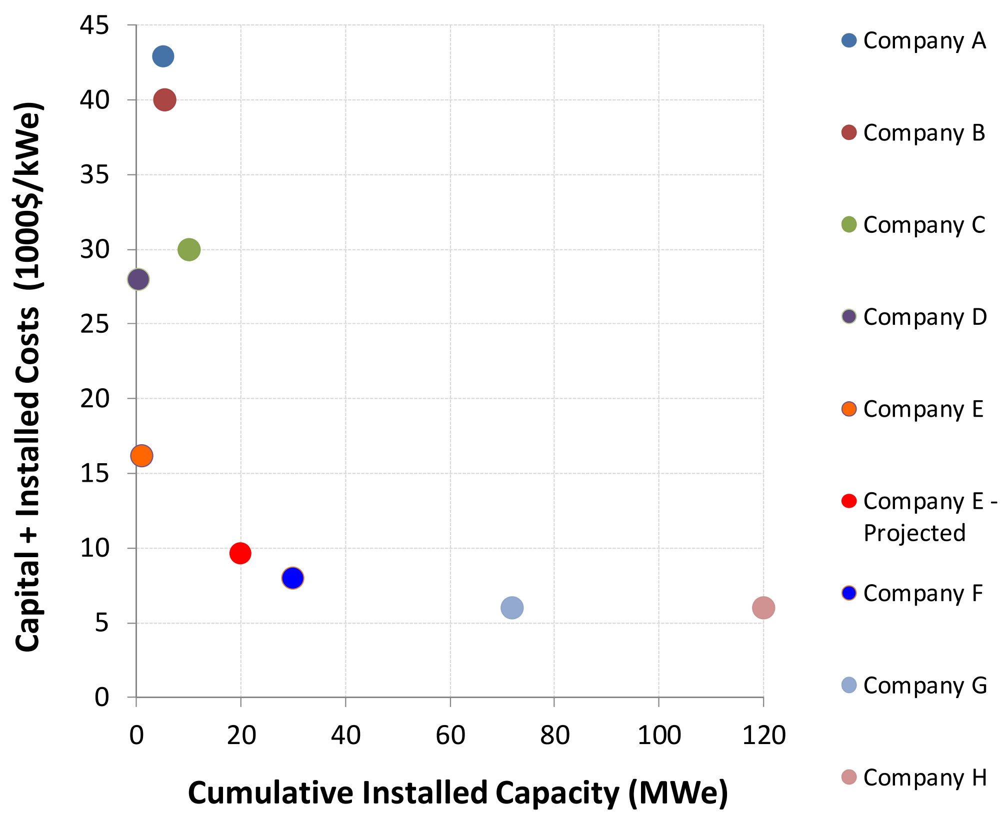

Figure 3.5. Capital and Installations Costs versus Installed Capacity of CHP-FCSs from Different Manufacturers

3.4 Projected Future Micro-CHP-FCS Business Case

While the business case for micro-CHP-FCSs may not be made now for all locations and applications, based on the current utility prices, available government incentives, and fuel cell costs, the business case will continue to improve. Using the projected prices of electricity and natural gas, and anticipated decline in fuel cell costs as a result of mass production and improvements resulting from research and development, estimates of the levelized cost of the system, both with and without incentives, can be compared to energy prices.

Figure 3.6 shows the average commercial cost per unit of energy for selected cities and the national average based on the values provided in Section 2.1. The average commercial cost per unit of energy was calculated using the historical and projected costs of commercial electricity and natural-gas/heating costs for the same unit of energy as the micro-CHP-FCS in the case study (i.e., same proportion of electricity to heat, 5 kWe/unit:5.5 kWt/unit). When developing the data that is the basis for Figure 3.6, we assumed that the heat energy provided at each city is generated by using natural gas rather than electricity. It also includes the current and projected cost per unit of energy for micro-CHP-FCSs.

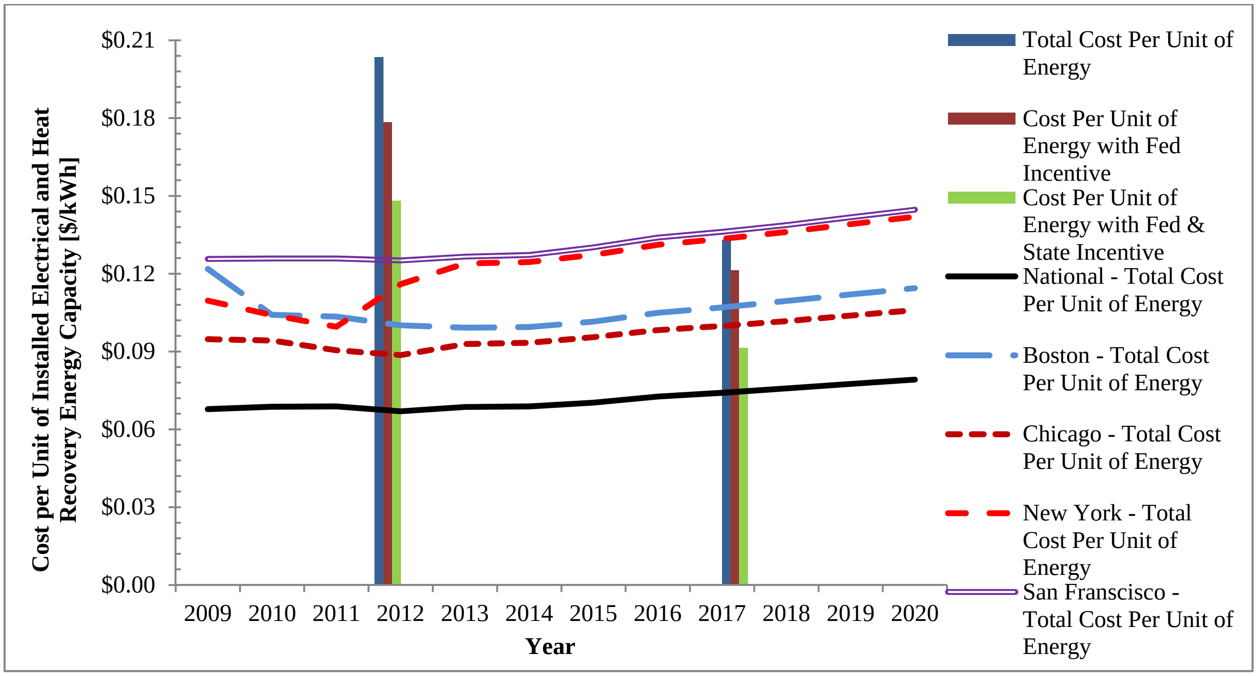

Figure 3.6. Historical and Projected Cost per Unit of Energy Along with the Current and Projected CHP-FCS Levelized Costs Calculated on the Basis of a 5 kWe and 5.5 kWt Micro-CHP-FCS Unit. Note: National and city costs per unit energy assume heat is generated by natural gas.

Current (2012) micro-CHP-FCS costs were calculated using the four installations discussed in this case study. The projected costs (2017) were based on the higher production level estimates assumed in Section 3.2. For the micro-CHP-FCSs installed in the case study, about one-third of the project capital costs were covered by the federal tax credits cost share, state tax credits, or rebates cost share. It is not entirely clear if subsidies will continue at this rate for the next few years. However, for simplicity, the government incentives were assumed to be the same for all new installations for the next 5 years in this analysis.

In summary, for current (2012) micro-CHP-FCS costs, the combination of federal and state incentives reduces micro-CHP-FCS costs to being within approximately 17% of being economically competitive with existing average commercial prices in San Francisco. However, the projected costs (2017) of micro-CHP-FCSs indicate that they will compete more closely with commercial average energy prices in San Francisco and New York City, even without government incentives. Future government incentives (2017), if continued at current levels, could further make micro-CHP-FCSs more closely competitive with commercial average energy prices in other major cities, including within approximately 20% of the national average.

4.0 Conclusions

A business case has been developed to help interested businesses understand the applications, economics, and operational parameters for micro-CHP-FCSs in the power output range of 5 to 50 kWe. When considering using such a system, the flow chart in Figure 4.1 provides insight into areas that should be considered.

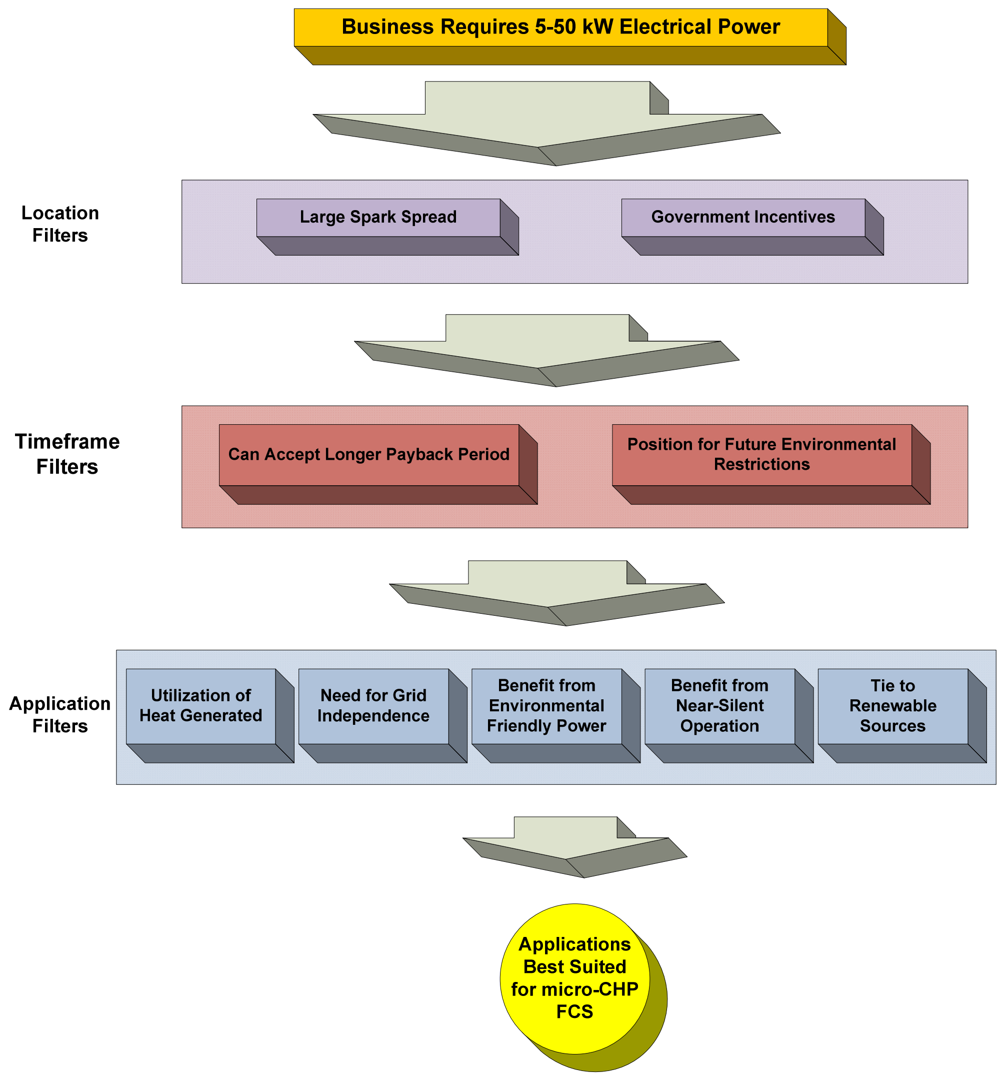

Figure 4.1. Considerations in Determining Applications Best Suited for Micro-CHP-FCSs

The locations that should be considered for these applications are those with a large spark spread and/or those having significant government incentives available for CHP technologies. California, the Upper Midwest, and the Northeast currently have both significant government incentives and large spark spreads, so those areas are strong candidates. Because of the higher cost of micro-CHP-FCS as compared to alternative sources of CHP, early-adopters should be willing to accept a longer payback period. In exchange for higher initial costs, the micro-CHP-FCSs are more fuel efficient and offer marked annual fuel-cost savings over their operating lifetime.

Depending on the particular needs, sites, and operating regimes of potential adopters, additional benefits may also help make the business case. Applications that use the high relative fraction of heat generated in a CHP, that have a need a reliable source of power, and/or can benefit from an environmentally friendly power source should be considered strong candidates for micro-CHP-FCSs. This study found that hospitals, retirement centers, hotels, dormitories, and similar facilities are good candidates because of their near-continual requirement for heated water. Hospitals, emergency response services, telecommunications businesses, information and order-processing businesses, manufacturing operations, and retail facilities are significantly impacted by outages and could benefit from reliable power. In addition, companies with shareholders, customers, or competitors interested in sustainability would benefit from environmentally friendly power production. These companies may also be interested in renewable power. The use of fuel cells to provide baseload power can help further establish renewable sources such as solar and wind.

In the case of companies for which a good business case cannot yet be made, the market is predicted to continue to grow at a rapid rate. With the increased growth and advancements expected from fuel-cell research and development, the manufacturing cost of FCSs is expected to continue to decline while the reliability and efficiency the systems are expected to increase. Within 5 years, at the expected rate of growth, the business case for these systems is expected to continue to strengthen. This may allow potential micro-CHP-FCS users that do not meet the criteria in Figure 4.1 to make a strong business case for their use in the future.

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Appendix A

Building Modeling

Appendix A

Building Modeling

This section describes the results of a modeling effort using coupled building-energy-system computer simulations to evaluate supplementing conventional electrical and heat systems in a building with a combined heat and power fuel cell system (CHP-FCS). It focuses on integrating CHP-FCS supplied heat and electricity with thermal and electrical demands in commercial buildings. The study was performed for a variety of the building types, building sizes, and climates. The high-temperature polymer electrolyte membrane (HTPEM fuel cell) systems evaluated in this study provide heat to buildings at an average temperature of about 47°C, according to independent measurements, and at a maximum temperature of 65°C, according to manufacturer statements. Therefore, the heat generated from the CHP can be used for water pipes in radiant heating systems for space heating (45°C) and for heating domestic hot water (50°C). It may be able to boost the temperatures for hot water coils in air handlers for space heating (82°C), hot water coils in variable-air-volume (VAV) box reheat coils for space heating (82°C), regenerate a desiccant in a dehumidification system (65 to 150°C), and heat for absorption chillers for space cooling (70 to 200°C). However, it will not be able to replace these types of systems. As a result, only the space heating and domestic hot water heating are evaluated here.

We used the EnergyPlus software to simulate several building types—a small office building, a small hotel, a small hospital, a quick-service restaurant, a small school, and an apartment building. We extracted space-heating and service-water heating demand data over time, as well as the electricity demand over time at 60-minute time intervals over the course of 1 year. Using this data, we examined the portion of the building heating demand that could potentially be served by an FCS based on temperature limitations and the quantity of thermal energy supplied by the FCS. EnergyPlus calculates the heating and cooling loads necessary to maintain thermal control set points, conditions throughout a heating, ventilation, and air conditioning system and coil loads, and the energy consumption of primary plant equipment as well as other simulation details needed to verify that the simulation is performing as the actual building's energy generation and consumption characteristics would. An example of data generated from EnergyPlus using a reference building (described in the following section) is shown in Figure A.1.

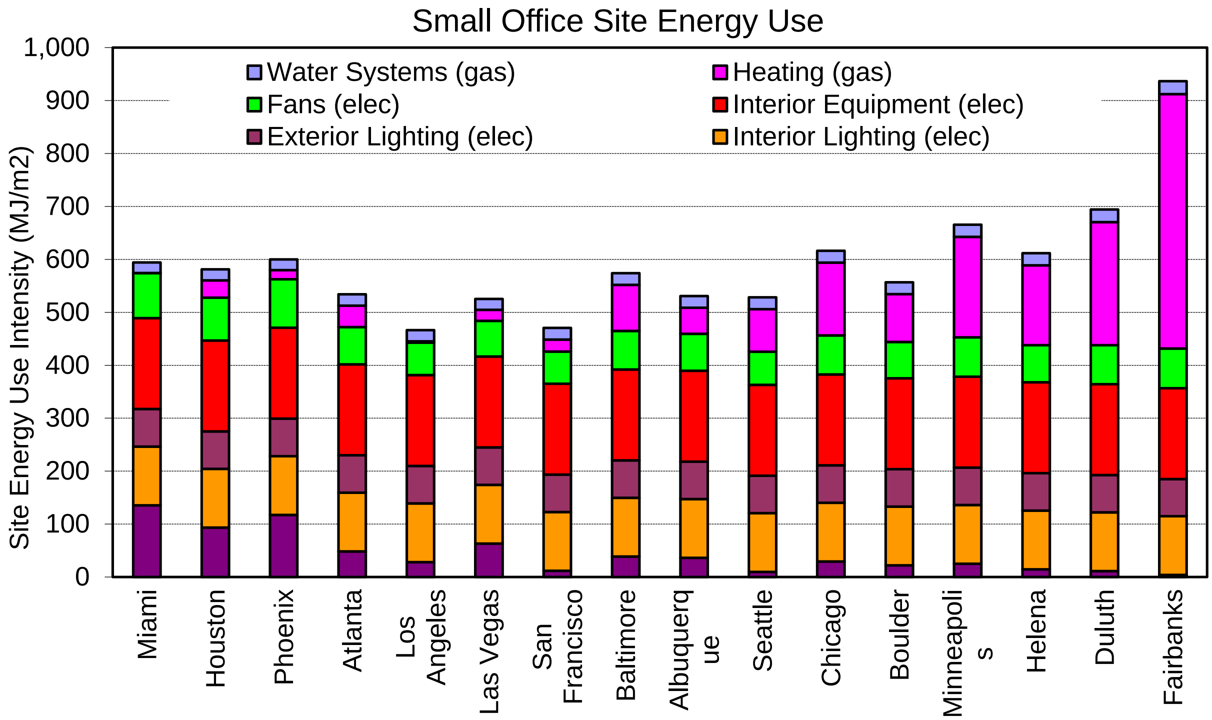

Figure A.1. Example of Building-Energy-Use Data Available from the EnergyPlus Building Model

In this work, we used the U.S. Department of Energy (DOE) Commercial Reference Building Models of the National Building Stock for the research into the integration of fuel cells in buildings. These models represent reasonably realistic building characteristics and construction practices; they directly characterize more than 60% of the commercial building stock and are very similar to other commercial building types. For this study, the DOE Commercial Reference Building New Construction 90.1-2004 models are used. As an example, the specific buildings simulated for Chicago are shown in Table A.1.

Table A.1. Floor Area and Energy Demand of Building Simulated

Building Type	Floor Area (m^2)	Chicago Annual Electric Energy (excluding electric energy used for heating) (GJ)	Chicago Annual Electric and Gas Energy used for Heating (GJ)
Small Office	618.01	234.97	80.93
Small Hotel	4013.59	2049.52	1135.38
Small Hospital	20218.99	24611.31	10768.22
Restaurant	232.34	688.84	1050.64
School	19592.0	10879.87	8916.46
Apartment	3134.59	843.9	827.29

The buildings were simulated using TMY3 weather files for New York City, Chicago, Boston, and San Francisco. Key assumptions that were made in this evaluation are described below:

1. The FCS thermal output was set to either 11 kW or 22 kW with an exhaust temperature of 65°C.

2. The heat exchangers used to transport the heat from the FCS to the building systems are 100% efficient.
3. The FCS operates constantly for all hours throughout the year. When the heat supplied by the fuel cell exceeds the heat demanded by the building, the heat is released to the environment.

Building operating schedules and the thermal and electrical demands are those specified in the DOE reference buildings. In Table A.2, typical winter and summer weeks are given for these locations. The simulations are run for an entire year and all energy calculations are performed for annual data. In addition, detailed performance profiles are examined for typical winter and summer weeks.

Table A.2. Typical Winter and Summer Weeks for the Weather Locations Used for Simulation

Location	Typical Winter Week	Typical Summer Week
New York	November 22–28	June 5–11
Boston	December 22–28	July 27–August 2
Chicago	January 27–February 2	August 24–30
San Francisco	February 15–21	September 5–11

A.1 Air-Based Space-Heating System

As shown in Figure A.2, the small office contains five packaged single-zone air conditioners (PSZ-ACs) containing gas furnace heating coils each serving one of the five thermal zones in the building. A PSZ-AC is assembled at a factory and installed as a self-contained unit. Some types of electric packaged units are also called “direct expansion,” or DX, units. Packaged units are in contrast with the heating, ventilation, and air conditioning system in a large office that is an engineer-specified unit built up from individual components for use in a given building. PSZ-AC units are generally mounted on the roof of the building, but sometimes are installed on a slab outside the building. Packaged units produce warm or cool air directly and distribute it throughout the building through ducts or a similar distribution system. The temperature of warm air produced by the gas furnace heating coil in the PSZ-AC and delivered to the space in the San Francisco climate is maintained between 25 and 40°C. The annual heating demand for space heating is 1390 kWh for this small office building. The average space-heating demand (when the system is operating) on a typical winter weekday is 3 kW for the small office building.

In the simulation of the small office building model in San Francisco weather, the rooftop unit supply air temperature (Supply Temperature [°C], T_supply2) in winter is maintained at 23°C by the system controller, as shown in Figure A.2. The mass flow rate of the air to the space (flow rate [kg/s]), varies to maintain the air temperature in the space at a given set point to maintain comfort in the space. The temperature of the air at the return to the space-heating system (Return Temperature [°C]), varies based on heating load in the space and may be approximately 21°C.

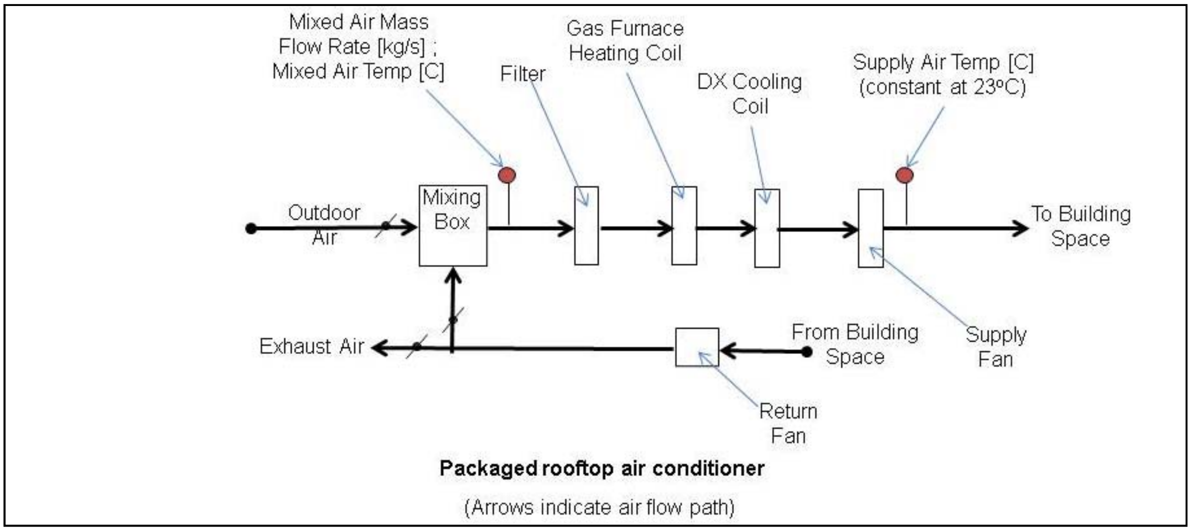

Figure A.2. Typical Air-Based Space-Heating System

A.2 Service-Water Heating System

In the models, a natural-gas fueled boiler is used to heat service water (heated water used in restrooms and in kitchens) in both small and large office building models. According to the DOE reference models, the usage in an office building is assumed to be 1 gallon per occupant per day divided evenly over a 9 hour period (the length of a typical work day). Similar assumptions are established for other building types simulated in this work. The supply water temperature from the boiler in the model is maintained at 60°C (in actual buildings the temperature of the water from the faucet is typically not higher than 50°C to prevent scalding or burns). The temperature of the makeup water is determined by the city supply water temperature and is assumed to be between 14.3 and 18.5°C, and is a function of the season.

The value of the net demand required to meet the service-water heating set point (service-water heating demand [kW]) is calculated independently of the efficiency of the heating equipment and is 551 kWh for the small office building in San Francisco. The average service-water heating demand (when the system is operating) on a typical winter weekday is 1.7 kW for the small office building.

The value of the fluid mass flow rate at the inlet to the service-water heating system (service-water heating system flow rate [kg/s]) varies based on service-water use in the space.

A.3 Calculation of Heating Load Potentially Accessible by Fuel Cell System

The time series data from the simulation includes the heating system supply and return temperatures [T_{supply}, T_{return}] and flow rate [$\dot{m}$]. These values are based on satisfying the building demand 100% of the time. Flow of heat [$\dot{Q}$] to the building space or the building, hot water is calculated using the equation:

$$\dot{Q} = \dot{m}c_p(T_{supply} - T_{return}) \tag{A.1}$$

where $c_p$is the specific heat of water at 4.181 kJ/kg°C [1.006 kJ/kg°C for dry air]

We calculate the portion of building heating demand at low enough temperature that this heat could be served by an HTPEM FCS [$\dot{Q}_F$] assuming the return water (air in the case of an air-based system) is heated to the FCS exhaust temperature at the outlet of the heat exchanger [T_H]; in this preliminary study, heat exchanger characteristics and limitations are not considered. The term $\dot{Q}_F$ is therefore calculated based on the equation:

$$IF\ T_{return} < T_H$$

$$THEN$$

$$\dot{Q}_F = \max\left(\dot{m}c_p(T_H - T_{return}), FCS\ thermal\ capacity\right)$$

$$ELSE$$

$$\dot{Q}_F = 0 \qquad \text{(A.2)}$$

The above calculation is performed at each time step and is repeated for space heating as well as service-water heating. The resulting total heating demand that could potentially be served by an FCS is the sum of the space-heating demand accessible by the FCS and the service-water heating demand accessible by the FCS.

Appendix B

Detailed Results of Building Modeling

Appendix B

Detailed Results of Building Modeling

Detailed results of building modeling are presented in this appendix. For each of the six building types simulated, micro-CHP-FCS utilization was calculated based on two separate analyses: 11 kW and 22 kW thermal output.

Annual space-heating and domestic hot water heating usage data is obtained separately from the building simulation and then post-processed to calculate micro-CHP-FCS utilization. This energy demand is used to calculate the quantity of the heat provided by the micro-CHP-FCS as compared to what is required by the building. In addition, demand for space heating and domestic hot water heating on a single typical winter weekday is documented for each city considered. Finally, the micro-CHP-FCS utilization for the total building for each hour in the year is calculated and documented as:

1. Percent of total annual building heating demand that can be satisfied by a micro-CHP-FCS
2. Number of hours in a year when all the thermal energy generated by the micro-CHP-FCS is able to be used in the building
3. Thermal energy generated by micro-CHP-FCS that is not used assuming it operates continuously throughout the year
4. Electric energy generated by micro-CHP-FCS not used assuming it operates continuously throughout the year.

Such an hourly calculation is necessary because the building heating energy demand varies seasonally based on the weather and hourly based on building occupancy; therefore, there are times when the thermal energy generated by the micro-CHP-FCS may exceed the quantity required by the building at that hour.

Table B.1. Simulation Results Based on 11 kW Thermal Output Micro-CHP-FCS for Office Buildings

Results based on 11kW thermal output FCS	Units	Office New York	Office Boston	Office Chicago	Office San Francisco
Space-Heating System					
Annual building thermal energy use [kWh]	kWh	13,084	15,535	19,278	1,987
Percent of total building heat demand	%	96	96	97	78
Typical Winter Week	Calendar dates	Nov 22-28	Dec 22-28	Jan 27-2	Feb 15-21
Peak space-heating demand on typical winter weekday	kW	23	18	36	5
Average space-heating demand (when the system is operating) on typical winter weekday	kW	3	2	11	0
Percent of hours annually in which the space-heating load is satisfied FCS	%	100	100	100	100
Percent of annual building space-heating demand satisfied by an FCS [%]	%	84	83	78	100
	kWh	11,016	12,969	15,020	1,985
Service-Water Heating System					
Annual use	kWh	562	621	621	551
Percent of total building heat demand	%	4	4	3	22
Peak service-water heating demand on typical winter weekday	kW	0	0	0	0
Average service-water heating demand (when the system is operating) on typical winter weekday	kW	0	0	0	0
Percent of hours annually in which the service-water heating load is in part potentially accessible by HTPEM FCS at 47°C	%	100	100	100	100
Percent of annual building service-water heating demand satisfied by an FCS	%	100	100	100	100
	kWh	562	621	621	551
Total Building					
Percent of total building heating demand that can be satisfied by an FCS	%	85	84	78	100
Number of hours in a year when all the thermal energy generated by the FCS is able to be used in the building	Hours	426	517	705	4
	%	4.9%	5.9%	8.0%	0.0%
Thermal Energy Generated by FCS Not Used	kWh	84,817	82,817	80,784	93,824
	%	88.0%	85.9%	83.8%	97.4%
Electric Energy Generated by FCS Not Used	kWh	29,995	30,771	30,051	32,382
	%	34.2%	35.1%	34.3%	37.0%

Table B.2. Simulation Results Based on 11 kW Thermal Output Micro-CHP-FCS for Hotel Buildings

Results based on 11 kW thermal output FCS	Units	Hotel New York	Hotel Boston	Hotel Chicago	Hotel San Francisco
Space-Heating System					
Annual building thermal energy use [kWh]	kWh	Further work is needed to calculate space-heating demand met by FCS because each room has a separate heating unit. If this heat could be provided by the micro-CHP-FCS, the heat utilization could be improved.			
Percent of total building heat demand	%				
Typical Winter Week	Calendar dates				
Peak space-heating demand on typical winter weekday	kW				
Average space-heating demand (when the system is operating) on typical winter weekday	kW				
Percent of hours annually in which the space-heating load is satisfied FCS	%				
Percent of annual building space-heating demand satisfied by an FCS [%]	%				
	kWh				
Service-Water Heating System					
Annual use	kWh	83,291	90,656	90,656	81,962
Percent of total building heat demand—service water only	%	11	12	12	11
Peak service-water heating demand on typical winter weekday	kW	27	31	32	27
Average service-water heating demand (when the system is operating) on typical winter weekday	kW	10	11	12	10
Percent of hours annually in which the service-water heating load is in part potentially accessible by HTPEM FCS at 47°C	%	100	100	100	100
Percent of annual building service-water heating demand satisfied by an FCS	%	76	73	73	77
	kWh	63,663	66,455	66,455	63,298
Total Building					
Percent of total building heating demand that can be satisfied by an FCS—service water only	%	12	12	12	12
Number of hours in a year when all the thermal energy generated by the FCS is able to be used in the building	Hours	3,321	3,576	3,576	3,172
	%	37.9%	40.8%	40.8%	36.2%
Thermal Energy Generated by FCS Not Used	kWh	32,697	29,905	29,905	33,062
	%	33.9%	31.0%	31.0%	34.3%
		Note: Hotel number of hours in a year when the FCS is operating at full capacity only for service hot water.			
Electric Energy Generated by FCS Not Used	kWh	None. The minimum electric demand is 31 kW, therefore it is always higher than electricity provided by FCS			
	%				

Table B.3. Simulation Results Based on 11 kW Thermal Output Micro-CHP-FCS for Hospital Buildings

Results based on 11kW thermal output FCS	Units	Hospital New York	Hospital Boston	Hospital Chicago	Hospital San Francisco
Space-Heating System					
Annual building thermal energy use [kWh]	kWh	1,833,320	1,910,515	1,957,677	1,745,858
Percent of total building heat demand	%	94	94	94	94
Typical Winter Week	Calendar dates	Nov 22-28	Dec 22-28	Jan 27-2	Feb 15-21
Peak space-heating demand on typical winter weekday	kW	745	721	989	672
Average space-heating demand (when the system is operating) on typical winter weekday	kW	259	238	442	209
Percent of hours annually in which the space-heating load is satisfied FCS	%	100	100	100	100
Percent of annual building space-heating demand satisfied by an FCS [%]	%	5	5	5	6
	kWh	96,360	96,360	96,360	96,360
Service-Water Heating System					
Annual use	kWh	113,781	123,649	123,645	112,004
Percent of total building heat demand	%	6	6	6	6
Peak service-water heating demand on typical winter weekday	kW	26	29	31	25
Average service-water heating demand (when the system is operating) on typical winter weekday	kW	13	15	17	13
Percent of hours annually in which the service-water heating load is in part potentially accessible by HTPEM FCS at 47°C	%	100	100	100	100
Percent of annual building service-water heating demand satisfied by an FCS	%	74	71	71	75
	kWh	84,048	87,496	87,490	83,647
Total Building					
Percent of total building heating demand that can be satisfied by an FCS	%	5	5	5	5
Number of hours in a year when all the thermal energy generated by the FCS is able to be used in the building	Hours	3,998	4,185	4,176	3,839
	%	45.6%	47.8%	47.7%	43.8%
Thermal Energy Wasted	kWh	12,312	8,864	8,870	12,713
	%	12.8%	9.2%	9.2%	13.2%
		Note: Hospital number of hours in a year when the FCS is operating at full capacity only for service hot water. For space heating, the FCS will be used 100% of the hours			
Electric Energy Wasted	kWh	None. The minimum electric demand is 340 kW, therefore it is always higher than the electricity provided by FCS			
	%				

Table B.4. Simulation Results Based on 11 kW Thermal Output Micro-CHP-FCS for Restaurant Buildings

Results based on 11kW thermal output FCS	**Units**	**Quick-Service Restaurant New York**	**Quick-Service Restaurant Boston**	**Quick-Service Restaurant Chicago**	**Quick-Service Restaurant San Francisco**
Space-Heating System					
Annual building thermal energy use [kWh]	kWh	77,536	95,745	111,148	21,468
Percent of total building heat demand	%	83	85	87	58
Typical Winter Week	Calendar dates	Nov 22-28	Dec 22-28	Jan 27-2	Feb 15-21
Peak space-heating demand on typical winter weekday	kW	50	43	98	19
Average space-heating demand (when the system is operating) on typical winter weekday	kW	19	13	47	3
Percent of hours annually in which the space-heating load is satisfied FCS	%	100	100	100	100
Percent of annual building space-heating demand satisfied by an FCS [%]	%	44	41	35	85
	kWh	33,941	38,984	38,593	18,343
Service-Water Heating System					
Annual use	kWh	15,957	17,341	17,341	15,708
Percent of total building heat demand	%	17	15	13	42
Peak service-water heating demand on typical winter weekday	kW	4	4	4	4
Average service-water heating demand (when the system is operating) on typical winter weekday	kW	2	2	2	2
Percent of hours annually in which the service-water heating load is in part potentially accessible by HTPEM FCS at 47°C	%	100	100	100	100
Percent of annual building service-water heating demand satisfied by an FCS	%	100	100	100	100
	kWh	15,957	17,341	17,341	15,708
Total Building					
Percent of total building heating demand that can be satisfied by an FCS	%	47	43	37	89
Number of hours in a year when all the thermal energy generated by the FCS is able to be used in the building	Hours	2,679	3,175	3,232	722
	%	30.6%	36.2%	36.9%	8.2%
Thermal Energy Wasted	kWh	57,357	52,256	51,710	73,754
	%	59.5%	54.2%	53.7%	76.5%
Electric Energy Wasted	kWh	357	401	409	365
	%	0.4%	0.5%	0.5%	0.4%

Table B.5. Simulation Results Based on 11 kW Thermal Output Micro-CHP-FCS for School Buildings

Results based on 11kW thermal output FCS	**Units**	**School New York**	**School Boston**	**School Chicago**	**School San Francisco**
Space-Heating System					
Annual building thermal energy use [kWh]	kWh	348,437	378,963	463,698	117,865
Percent of total building heat demand	%	79	79	82	57
Typical Winter Week	Calendar dates	Nov 22-28	Dec 22-28	Jan 27-2	Feb 15-21
Peak space-heating demand on typical winter weekday	kW	528	431	753	244
Average space-heating demand (when the system is operating) on typical winter weekday	kW	71	50	250	9
Percent of hours annually in which the space-heating load is satisfied FCS	%	100	100	100	100
Percent of annual building space-heating demand satisfied by a FCS [%]	%	8	8	7	14
	kWh	26,503	29,588	31,718	15,955
Service-Water Heating System					
Annual use	kWh	93,825	102,738	102,734	90,029
Percent of total building heat demand	%	21	21	18	43
Peak service-water heating demand on typical winter weekday	kW	41	47	50	40
Average service-water heating demand (when the system is operating) on typical winter weekday	kW	11	13	17	11
Percent of hours annually in which the service-water heating load is in part potentially accessible by HTPEM FCS at 47°C	%	100	100	100	100
Percent of annual building service-water heating demand satisfied by a FCS	%	49	46	46	51
	kWh	45,739	47,406	47,401	45,808
Total Building					
Percent of total building heating demand that can be satisfied by a FCS	%	12	12	10	24
Number of hours in a year when all the thermal energy generated by the FCS is able to be used in the building	Hours	3,553	3,661	3,988	3,255
	%	41%	42%	46%	37%
Thermal Energy Generated by FCS Not Used	kWh	42,761	40,732	37,904	46,361
	%	44%	42%	39%	48%
Electric Energy Generated by FCS Not Used	kWh	None. The minimum electric demand is 87 kW, therefore it is always higher than electricity provided by FCS			

Table B.6. Simulation Results Based on 11 kW Thermal Output Micro-CHP-FCS for Apartment Buildings

Results based on 11kW thermal output FCS	**Units**	**Apartment New York**	**Apartment Boston**	**Apartment Chicago**	**Apartment San Francisco**
Space-Heating System					
Annual building thermal energy use [kWh]	kWh	This building type contains 23 individual apartments with individual space-heating and cooling systems. Further work is needed to examine space-heating energy use supplied by the fuel cell.			
Percent of total building heat demand	%				
Typical Winter Week	Calendar dates				
Peak space-heating demand on typical winter weekday	kW				
Average space-heating demand (when the system is operating) on typical winter weekday	kW				
Percent of hours annually in which the space-heating load is satisfied FCS	%				
Percent of annual building space-heating demand satisfied by a FCS [%]	%				
	kWh				
Service-Water Heating System					
Annual use	kWh	59,822	66,087	66,087	58,689
Percent of total building heat demand—service water only	%	100	100	100	100
Peak service-water heating demand on typical winter weekday	kW	14	16	17	14
Average service-water heating demand (when the system is operating) on typical winter weekday	kW	7	9	9	7
Percent of hours annually in which the service-water heating load is in part potentially accessible by HTPEM FCS at 47°C	%	100	100	100	100
Percent of annual building service-water heating demand satisfied by a FCS	%	95	92	92	97
	kWh	56,683	60,654	60,654	57,037
Total Building					
Percent of total building heating demand that can be satisfied by a FCS—service water only	%	95	92	92	97
Number of hours in a year when all the thermal energy generated by the FCS is able to be used in the building	Hours	1,625	2,218	2,218	1,521
	%	18.6%	25.3%	25.3%	17.4%
Thermal Energy Generated by FCS Not Used	kWh	39,677	35,706	35,706	39,323
	%	41.2%	37.1%	37.1%	40.8%
Electric Energy Generated by FCS Not Used	kWh	None. The minimum electric demand is 14 kW, therefore it is always higher than electricity provided by FCS.			

Table B.7. Simulation Results Based on 22 kW Thermal Output Micro-CHP-FCS for Office Buildings

Results based on 22 kW thermal output FCS	Units	Office New York	Office Boston	Office Chicago	Office San Francisco
Space-Heating System					
Annual building thermal energy use [kWh]	kWh	13,084	15,535	19,278	1,987
Percent of total building heat demand	%	96	96	97	78
Typical Winter Week	Calendar dates	Nov 22-28	Dec 22-28	Jan 27-2	Feb 15-21
Peak space-heating demand on typical winter weekday	kW	23	18	36	5
Average space-heating demand (when the system is operating) on typical winter weekday	kW	3	2	11	0
Percent of hours annually in which the space-heating load is satisfied FCS	%	100	100	100	100
Percent of annual building space-heating demand satisfied by an FCS [%]	%	99	98	97	100
	kWh	12,896	15,301	18,697	1,987
Service-Water Heating System					
Annual use	kWh	562	621	621	551
Percent of total building heat demand	%	4	4	3	22
Peak service-water heating demand on typical winter weekday	kW	0	0	0	0
Average service-water heating demand (when the system is operating) on typical winter weekday	kW	0	0	0	0
Percent of hours annually in which the service-water heating load is in part potentially accessible by HTPEM FCS at 47°C	%	100	100	100	100
Percent of annual building service-water heating demand satisfied by an FCS	%	100	100	100	100
	kWh	562	621	621	551
Total Building					
Percent of total building heating demand that can be satisfied by an FCS	%	99	99	97	100
Number of hours in a year when all the thermal energy generated by the FCS is able to be used in the building	Hours	48	58	126	-
	%	0.5%	0.7%	1.4%	0.0%
Thermal Energy Wasted	kWh	179,265	176,801	173,411	190,182
	%	93.0%	91.7%	90.0%	98.7%
Electric Energy Wasted	kWh	109,346	111,318	109,931	114,555
	%	62.4%	63.5%	62.7%	65.4%

Table B.8. Simulation Results Based on 22 kW Thermal Output Micro-CHP-FCS for Hotel Buildings

Results based on 22 kW thermal output FCS	Units	Hotel New York	Hotel Boston	Hotel Chicago	Hotel San Francisco
Space-Heating System					
Annual building thermal energy use [kWh]	kWh	Further work is required to calculate space-heating demand met by FCS because each room has a separate heating unit. If this heat could be provided by the micro-CHP-FCS, the heat utilization could be improved.			
Percent of total building heat demand	%				
Typical Winter Week	Calendar dates				
Peak space-heating demand on typical winter weekday	kW				
Average space-heating demand (when the system is operating) on typical winter weekday	kW				
Percent of hours annually in which the space-heating load is satisfied FCS	%				
Percent of annual building space-heating demand satisfied by an FCS [%]	%				
	kWh				
Service-Water Heating System					
Annual use	kWh	83,291	90,656	90,656	81,962
Percent of total building heat demand—service water only	%	11	12	12	11
Peak service-water heating demand on typical winter weekday	kW	27	31	32	27
Average service-water heating demand (when the system is operating) on typical winter weekday	kW	10	11	12	10
Percent of hours annually in which the service-water heating load is in part potentially accessible by HTPEM FCS at 47°C	%	100	100	100	100
Percent of annual building service-water heating demand satisfied by an FCS	%	99	98	98	100
	kWh	82,484	89,133	89,133	81,580
Total Building					
Percent of total building heating demand that can be satisfied by an FCS –service water only	%	21	21	21	21
Number of hours in a year when all the thermal energy generated by the FCS is able to be used in the building	Hours	312	463	463	212
	%	3.6%	5.3%	5.3%	2.4%
Thermal Energy Wasted	kWh	110,236	103,587	103,587	111,140
	%	57.2%	53.7%	53.7%	57.7%
		Note: Hotel number of hours in a year when the FCS is operating at full capacity only for service hot water			
Electric Energy Wasted	kWh	None. The minimum electric demand is 31 kW, therefore it is always higher than electricity provided by FCS			
	%				

Table B.9. Simulation Results Based on 22 kW Thermal Output Micro-CHP-FCS for Hospital Buildings

Results based on 22 kW thermal output FCS	Units	Hospital New York	Hospital Boston	Hospital Chicago	Hospital San Francisco
Space-Heating System					
Annual building thermal energy use [kWh]	kWh	1,833,320	1,910,515	1,957,677	1,745,858
Percent of total building heat demand	%	94	94	94	94
Typical Winter Week	Calendar dates	Nov 22-28	Dec 22-28	Jan 27-2	Feb 15-21
Peak space-heating demand on typical winter weekday	kW	745	721	989	672
Average space-heating demand (when the system is operating) on typical winter weekday	kW	259	238	442	209
Percent of hours annually in which the space-heating load is satisfied FCS	%	100	100	100	100
Percent of annual building space-heating demand satisfied by an FCS [%]	%	11	10	10	11
	kWh	192,720	192,720	192,720	192,720
Service-Water Heating System					
Annual use	kWh	113,781	123,649	123,645	112,004
Percent of total building heat demand	%	6	6	6	6
Peak service-water heating demand on typical winter weekday	kW	26	29	31	25
Average service-water heating demand (when the system is operating) on typical winter weekday	kW	13	15	17	13
Percent of hours annually in which the service-water heating load is in part potentially accessible by HTPEM FCS at 47°C	%	100	100	100	100
Percent of annual building service-water heating demand satisfied by an FCS	%	98	96	96	99
	kWh	110,979	118,719	118,714	110,742
Total Building					
Percent of total building heating demand that can be satisfied by an FCS	%	10	9	9	10
Number of hours in a year when all the thermal energy generated by the FCS is able to be used in the building	Hours	903	1,273	1,277	907
	%	10.3%	14.5%	14.6%	10.4%
Thermal Energy Wasted	kWh	81,741	74,001	74,006	81,978
	%	42.4%	38.4%	38.4%	42.5%
		NOTE. Hospital number of hours in a year when the FCS is operating at full capacity only for service hot water. For space heating, the FCS will be used 100% of the hours			
Electric Energy Wasted	kWh	None. The minimum electric demand is 340 kW, therefore it is always higher than electricity provided by FCS			
	%				

Table B.10. Simulation Results Based on 22 kW Thermal Output Micro-CHP-FCS for Restaurant Buildings

Results based on 22 kW thermal output FCS	Units	Quick-Service Restaurant New York	Quick-Service Restaurant Boston	Quick-Service Restaurant Chicago	Quick-Service Restaurant San Francisco
Space-Heating System					
Annual building thermal energy use [kWh]	kWh	77,536	95,745	111,148	21,468
Percent of total building heat demand	%	83	85	87	58
Typical Winter Week	Calendar dates	Nov 22-28	Dec 22-28	Jan 27-2	Feb 15-21
Peak space-heating demand on typical winter weekday	kW	50	43	98	19
Average space-heating demand (when the system is operating) on typical winter weekday	kW	19	13	47	3
Percent of hours annually in which the space-heating load is satisfied FCS	%	100	100	100	100
Percent of annual building space-heating demand satisfied by an FCS [%]	%	72	69	62	99
	kWh	56,069	66,503	68,443	21,150
Service-Water Heating System					
Annual use	kWh	15,957	17,341	17,341	15,708
Percent of total building heat demand	%	17	15	13	42
Peak service-water heating demand on typical winter weekday	kW	4	4	4	4
Average service-water heating demand (when the system is operating) on typical winter weekday	kW	2	2	2	2
Percent of hours annually in which the service-water heating load is in part potentially accessible by HTPEM FCS at 47°C	%	100	100	100	100
Percent of annual building service-water heating demand satisfied by an FCS	%	100	100	100	100
	kWh	15,957	17,341	17,341	15,708
Total Building					
Percent of total building heating demand that can be satisfied by an FCS	%	73	69	62	99
Number of hours in a year when all the thermal energy generated by the FCS is able to be used in the building	Hours	1,767	2,261	2,521	97
	%	20.2%	25.8%	28.8%	1.1%
Thermal Energy Wasted	kWh	142,092	131,441	126,361	174,958
	%	73.7%	68.2%	65.6%	90.8%
Electric Energy Wasted	kWh	19,230	19,521	19,449	19,354
	%	11.0%	11.1%	11.1%	11.0%

Table B.11. Simulation Results Based on 22 kW Thermal Output Micro-CHP-FCS for School Buildings

Results based on 22kW thermal output FCS	**Units**	**School New York**	**School Boston**	**School Chicago**	**School San Francisco**
Space-Heating System					
Annual building thermal energy use [kWh]	kWh	348,437	378,963	463,698	117,865
Percent of total building heat demand	%	79	79	82	57
Typical Winter Week	Calendar dates	Nov 22-28	Dec 22-28	Jan 27-2	Feb 15-21
Peak space-heating demand on typical winter weekday	kW	528	431	753	244
Average space-heating demand (when the system is operating) on typical winter weekday	kW	71	50	250	9
Percent of hours annually in which the space-heating load is satisfied FCS	%	100	100	100	100
Percent of annual building space-heating demand satisfied by a FCS [%]	%	14	15	13	24
	kWh	50,003	55,561	60,068	28,599
Service-Water Heating System					
Annual use	kWh	93,825	102,738	102,734	90,029
Percent of total building heat demand	%	21	21	18	43
Peak service-water heating demand on typical winter weekday	kW	41	47	50	40
Average service-water heating demand (when the system is operating) on typical winter weekday	kW	11	13	17	11
Percent of hours annually in which the service-water heating load is in part potentially accessible by HTPEM FCS at 47°C	%	100	100	100	100
Percent of annual building service-water heating demand satisfied by a FCS	%	76	72	72	79
	kWh	71,423	73,933	73,932	71,532
Total Building					
Percent of total building heating demand that can be satisfied by a FCS	%	20	19	17	40
Number of hours in a year when all the thermal energy generated by the FCS is able to be used in the building	Hours	2,985	3,166	3,475	2,846
	%	34.1%	36.1%	39.7%	32.5%
Thermal Energy Generated by FCS Not Used	kWh	103,533	99,914	93,594	109,458
	%	53.7%	51.8%	48.6%	56.8%
Electric Energy Generated by FCS Not Used	kWh	None. The minimum electric demand is 87 kW, therefore it is always higher than electricity provided by FCS			

Table B.12. Simulation Results Based on 22 kW Thermal Output Micro-CHP-FCS for Apartment Buildings

Results based on 22kW thermal output FCS	**Units**	Apartment New York	Apartment Boston	Apartment Chicago	Apartment San Francisco
Space-Heating System					
Annual building thermal energy use [kWh]	kWh	This building type contains 23 individual apartments with individual space-heating and cooling systems. Further work is needed to examine space-heating energy use supplied by the fuel cell.			
Percent of total building heat demand	%				
Typical Winter Week	Calendar dates				
Peak space-heating demand on typical winter weekday	kW				
Average space-heating demand (when the system is operating) on typical winter weekday	kW				
Percent of hours annually in which the space-heating load is satisfied FCS	%				
Percent of annual building space-heating demand satisfied by a FCS [%]	%				
	kWh				
Service-Water Heating System					
Annual use	kWh	59,822	66,087	66,087	58,689
Percent of total building heat demand—service water only	%	100	100	100	100
Peak service-water heating demand on typical winter weekday	kW	14	16	17	14
Average service-water heating demand (when the system is operating) on typical winter weekday	kW	7	9	9	7
Percent of hours annually in which the service-water heating load is in part potentially accessible by HTPEM FCS at 47°C	%	100	100	100	100
Percent of annual building service-water heating demand satisfied by a FCS	%	100	100	100	100
	kWh	59,822	66,087	66,087	58,689
Total Building					
Percent of total building heating demand that can be satisfied by a FCS—service-water only	%	100	100	100	100
Number of hours in a year when all the thermal energy generated by the FCS is able to be used in the building	Hours	0	0	0	0
	%	0	0	0	0
Thermal Energy Generated by FCS Not Used	kWh	132,898	126,633	126,633	134,031
	%	69.0%	65.7%	65.7%	69.5%
Electric Energy Generated by FCS Not Used	kWh	7,044	7,936	7,171	0

Appendix C

Cost of an Electrical Outage at a Single Facility

Appendix C

Cost of an Electrical Outage at a Single Facility

The cost of power interruption is impacted by the time of day, location, and business type. The customer damage function is described in a study by Lawrence Berkley National Laboratory for the U.S. Department of Energy's Energy Storage Program, Office of Electric Transmission and Distribution [C.1]. The function is based on 24 studies conducted by eight utilities between 1989 and 2002. The studies included damages caused by power interruptions to different customer classes (i.e., residential and three sizes of commercial/industrial [small, medium, and large]). This damage function can be used to calculate outage costs for a specific type of customer. For instance, the estimated cost for an average customer caused by a 1 hour summer afternoon outage is:

Customer Class	Cost of Damage in 1 Hour Summer Afternoon
Residential	$3
Small and medium Commercial/Industrial	$1,200
Large Commercial/Industrial	$8,200

A white paper by visionsolutions.com concludes that customer damage is between $84,000 and $108,000 for every hour that power is lost to information technology systems [C.2]. In a similar study, PG&E estimated the direct cost of power outages to its customers per kWh of power not served. The results are shown below. Similar costs have been shown in other studies as well [C.3].

Customer Class	$/kWh of power not supplied
Industrial	$12.70–$424.80
Commercial	$40.60–$68.20
Agricultural	$11.50–$11.70
Residential	$5.10–$8.50

These figures are much greater than the price of electricity purchased ($/kWh). The value of these losses is referred to as the customer's value of service (VOS) [C.1]. According to the U.S. Environmental Protection Agency, VOS can be measured in terms of the direct costs of an outage imposed on customers as a result of damaged plant equipment, damaged product, maintenance costs, loss of revenue, cost of unproductive labor, and liability for safety/health. A facility can estimate their VOS by determining the number of outages they experience in a year and damages resulting by the outages.

Estimating the annual cost of outages for a facility can help them determine damages that could be avoided by installation of CHP-FCS. These values were developed for a small commercial building based on an example EPA has published on how to estimate cost of outages for an industrial plant [C.4]. Therefore, number and length of power outages are adjusted to match those of small commercial buildings. The number of outages is assumed to be once per season (four outages per year on average), and in this example, momentary outages cause disruption to building operations for 15 minutes assuming it takes that much time for data centers, networks, computers, and other equipment to be fully functional and staff to return to their normal performance levels. The building given in this example has a power demand of 100 kW (based on average demand of small commercial buildings simulated in this study including the small hotel and hospital) with a VOS of $40/kWh (which is on the lower side of the commercial building VOS shown above). The results of this example show that the cost of a power outage per hour is estimated to be $4,000 on average.

References:

C.1 Lawton L, M Sullivan, K Van Liere, A Katz, and J Eto. 2003. "A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys." LBNL-54365, Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley, California. Available at: http://certs.lbl.gov/pdf/54365.pdf.

C.2 Vision Solutions (2008). "Assessing the Financial Impact of Downtime: Understand the factors that contribute to the cost of downtime and accurately calculate its total cost in your organization." visionsolutions.com. Available at: http://www.strategiccompanies.com/pdfs/Assessing%20the%20Financial%20Impact%20of%20Downtime.pdf.

C.3 Centolella P. "Estimates of the Value of Uninterrupted Service for The Mid-West Independent System Operator." SAIC. Available at: http://www.hks.harvard.edu/hepg/Papers/2010/VOLL%20Final%20Report%20to%20MISO%20042806.pdf.

C.4 Environmental Protection Agency, "Calculating Reliability Benefits," Last Updated April 10, 2013. Available at: http://www.epa.gov/chp/basic/benefits.html

Appendix D

Details on Alternatives Comparison

Appendix D

Details on Alternatives Comparison

D.1 Principal Economic Assumptions

The tables that follow provide the life-cycle cost analysis for each alternative technology for San Francisco. This is an example of one of four locations considered in the business case. The results from this location were then averaged with the results of Boston, New York, and Chicago to obtain the average value presented in the report. This appendix indicates how the authors compared technologies in economic terms. Individual enterprises likely would conduct their own assessments to compare viable micro-CHP technologies.

Life-cycle costing typically relies on key economic assumptions. We evaluated the total installed costs expressed as $/KW, based on cost and performance information in the U.S. Environmental Protection Agency (EPA) Catalog of CHP technologies.[1] These costs include all taxes, delivery, installation, and site preparation. This information is now 5 years old; however, we could not find more reliable information collected in the interim. Examination of implicit price deflators for commercial and industrial equipment suggests that cost values expressed in 2007 or 2008 dollars remain equivalent in 2013, and no better cost information was identified, thus those costs are used without adjustment.

Several additional assumptions were made that have the same relative effects across all technologies. The economic life was assumed to be 10 years across technologies, based on the availability of extended warranties covering that period. We expect all technologies would actually perform longer, but for the cost of financing, 10 years was assumed. We assumed that these systems would have a 95% capacity factor, because that is the optimal operating regime for the micro-FCS technology. This implies that the commercial buildings using these CHP systems would have sufficient baseload hot water demand to require the CHP heat output nearly constantly. We also assumed the capital cost would be financed, rather than expensed. We assumed that the fuel savings from CHP operations should be counted in the estimation of levelized costs, as it is a subtraction from total fuel cost. This has the effect of greatly reducing the levelized costs. Levelized costs were compared with the assumed break-even levelized cost at prevailing commercial electricity rates, based on current commercial utility rates serving each city.

Some specific assumptions were made to use the EPA CHP Catalog technologies. The catalog examines actual applications of available technologies. Some of these are not sized to the 25 kWe examples we have considered for micro-CHP-PEM-FCS. The smallest gas reciprocating engine technology was a 50 KW system. The smallest microturbine system was a 30 KW system. We used the capital costs per KW for these systems, recognizing that a smaller system likely would have higher per-KW costs. Also, the reported total installed cost (without incentives) in the CHP catalog for a 10 KW PEM fuel cell without grid connection is about $9100/KW.[1] Experience on the test cases described in Chapter 4 suggests the first costs (without incentives) are much higher. This highlights the uncertainty of costing new technology. As explained in Section 3.5.3, we would expect the pace of cost reduction for PEM fuel cell systems to be more rapid than for other well-established CHP technologies, because far

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[1] U.S. Environmental Protection Agency (EPA). 2008. "Catalog of CHP Technologies." Accessed at: http://www.epa.gov/chp/documents/catalog_chptech_full.pdf (March 6, 2013).

fewer units have been produced to date than for the more mature technologies; however, we did not make a specific assumption about that in the analysis. Enterprises considering the PEM technology would be expected to negotiate case-specific equipment prices with vendors. Experience with the PEM technology will have a larger marginal effect on cost per unit, thus driving down the system cost faster in the near term, relative to other technologies.

San Francisco

Microturbine CHP

Inputs

$ 89,100	Total Capital Cost
1	Number of Units
$ 0.70	Gas Cost ($/therm)
35,119	Fuel Use therms/Yr
$ 84.00	Fuel Costs ($/MWh)
10	Life of Units
30	kWe per Unit effective output
95%	Capacity Factor
249,660	Annual Generation (KWh)
$ 0.030	O&M Cost ($/kWh)
6.0%	Loan/Bond Rate
13.0%	Loan/Bond Issuance Cost %
2.5%	Inflation
3.1%	Real Discont Rate
7.0%	Nominal Discount Rate
$ 0.1906	Average Utility Cost ($/kWh)
1.8%	Utility/Fuel Cost Escalator
20.59%	Expected incentives (% of cost)

Results

$0.0436	Nominal Levelized Cost $/KWh
$0.0458	Real Levelized Cost $/KWh
$363	Nominal Levelized Cost $/KW
$381	Real Levelized Cost $/KW

Market Entry Costs

$1,704	Nominal Levelized Cost $/KW
$1,713	Real Levelized Cost $/KW

Year	Annual Generation (kWh/Yr)	Annual Debt Service ($/Yr)	O&M Cost ($/Yr)	Fuel Cost ($/Yr)	Elec and Gas Net Savings $/yr	Total Cost ($/Yr)	Incentives ($/Yr)	Total Cost w/ Incentives ($/Yr)	Utility Cost ($/Yr)	Annual Debt Service ($/kWh)	O&M Cost ($/kWh)	Fuel Cost ($/kWh)	Total Cost ($/kWh)	Incentives ($/kWh)	Total Cost w/ Incentives ($/kWh)	Utility Cost ($/kWh)
2013	249,660	$13,680	$7,490	$24,583	$35,033	$10,720	$18,345	-$7,625	$47,585	$0.0548	$0.0300	$0.0985	$0.1833	$0.07348	$0.1098	$0.1906
2014	249,660	$13,680	$7,677	$25,026	$35,033	$11,349	$0	$11,349	$48,442	$0.0548	$0.0308	$0.1002	$0.1858	$0.00000	$0.1858	$0.1940
2015	249,660	$13,680	$7,869	$25,476	$35,033	$11,992	$0	$11,992	$49,314	$0.0548	$0.0315	$0.1020	$0.1884	$0.00000	$0.1884	$0.1975
2016	249,660	$13,680	$8,066	$25,935	$35,033	$12,647	$0	$12,647	$50,201	$0.0548	$0.0323	$0.1039	$0.1910	$0.00000	$0.1910	$0.2011
2017	249,660	$13,680	$8,267	$26,402	$35,033	$13,315	$0	$13,315	$51,105	$0.0548	$0.0331	$0.1057	$0.1937	$0.00000	$0.1937	$0.2047
2018	249,660	$13,680	$8,474	$26,877	$35,033	$13,997	$0	$13,997	$52,025	$0.0548	$0.0339	$0.1077	$0.1964	$0.00000	$0.1964	$0.2084
2019	249,660	$13,680	$8,686	$27,361	$35,033	$14,693	$0	$14,693	$52,961	$0.0548	$0.0348	$0.1096	$0.1992	$0.00000	$0.1992	$0.2121
2020	249,660	$13,680	$8,903	$27,853	$35,033	$15,403	$0	$15,403	$53,915	$0.0548	$0.0357	$0.1116	$0.2020	$0.00000	$0.2020	$0.2160
2021	249,660	$13,680	$9,126	$28,354	$35,033	$16,127	$0	$16,127	$54,885	$0.0548	$0.0366	$0.1136	$0.2049	$0.00000	$0.2049	$0.2198
2022	249,660	$13,680	$9,354	$28,865	$35,033	$16,865	$0	$16,865	$55,873	$0.0548	$0.0375	$0.1156	$0.2079	$0.00000	$0.2079	$0.2238

San Francisco

Gas Recipricating Engine

Inputs

$ 110,500	Total Capital Cost
1	Number of Units
$ 0.70	Gas Cost ($/therm)
49,932	Fuel Use therms/Yr
$ 84.00	Fuel Costs ($/MWh)
10	Life of Units
50	kWe per Unit effective output
95%	Capacity Factor
416,100	Annual Generation (KWh)
$ 0.030	O&M Cost ($/kWh)
6.0%	Loan/Bond Rate
13.0%	Loan/Bond Issuance Cost %
2.5%	Inflation
3.1%	Real Discont Rate
7.0%	Nominal Discount Rate
$ 0.1906	Average Utility Cost ($/kWh)
1.8%	Utility/Fuel Cost Escalator
20.59%	Expected incentives (% of cost)

Results

$0.0727	Nominal Levelized Cost $/KWh
$0.0745	Real Levelized Cost $/KWh
$605	Nominal Levelized Cost $/KW
$620	Real Levelized Cost $/KW

Market Entry Costs

$1,704	Nominal Levelized Cost $/KW
$1,713	Real Levelized Cost $/KW

Year	Annual Generation (kWh/Yr)	Annual Debt Service ($/Yr)	O&M Cost ($/Yr)	Fuel Cost ($/Yr)	Elec and Gas Net Savings $/yr	Total Cost ($/Yr)	Incentives ($/Yr)	Total Cost w/ Incentives ($/Yr)	Utility Cost ($/Yr)	Annual Debt Service ($/kWh)	O&M Cost ($/kWh)	Fuel Cost ($/kWh)	Total Cost ($/kWh)	Incentives ($/kWh)	Total Cost w/ Incentives ($/kWh)	Utility Cost ($/kWh)
2013	416,100	$16,965	$12,483	$34,952	$35,033	$29,368	$22,751	$6,617	$79,309	$0.0408	$0.0300	$0.0840	$0.1548	$0.05468	$0.1001	$0.1906
2014	416,100	$16,965	$12,795	$35,582	$35,033	$30,309	$0	$30,309	$80,736	$0.0408	$0.0308	$0.0855	$0.1570	$0.00000	$0.1570	$0.1940
2015	416,100	$16,965	$13,115	$36,222	$35,033	$31,269	$0	$31,269	$82,189	$0.0408	$0.0315	$0.0871	$0.1593	$0.00000	$0.1593	$0.1975
2016	416,100	$16,965	$13,443	$36,874	$35,033	$32,249	$0	$32,249	$83,669	$0.0408	$0.0323	$0.0886	$0.1617	$0.00000	$0.1617	$0.2011
2017	416,100	$16,965	$13,779	$37,538	$35,033	$33,249	$0	$33,249	$85,175	$0.0408	$0.0331	$0.0902	$0.1641	$0.00000	$0.1641	$0.2047
2018	416,100	$16,965	$14,123	$38,213	$35,033	$34,269	$0	$34,269	$86,708	$0.0408	$0.0339	$0.0918	$0.1666	$0.00000	$0.1666	$0.2084
2019	416,100	$16,965	$14,476	$38,901	$35,033	$35,310	$0	$35,310	$88,269	$0.0408	$0.0348	$0.0935	$0.1691	$0.00000	$0.1691	$0.2121
2020	416,100	$16,965	$14,838	$39,601	$35,033	$36,372	$0	$36,372	$89,858	$0.0408	$0.0357	$0.0952	$0.1716	$0.00000	$0.1716	$0.2160
2021	416,100	$16,965	$15,209	$40,314	$35,033	$37,456	$0	$37,456	$91,475	$0.0408	$0.0366	$0.0969	$0.1742	$0.00000	$0.1742	$0.2198
2022	416,100	$16,965	$15,590	$41,040	$35,033	$38,562	$0	$38,562	$93,122	$0.0408	$0.0375	$0.0986	$0.1769	$0.00000	$0.1769	$0.2238

San Francisco

Micro PEM Fuel Cell CHP

Inputs

$ 227,500	Total Capital Cost
5	Number of Units
$ 0.70	Gas Cost ($/therm)
19,592	Fuel Use therms/Yr
$ 84.00	Fuel Costs ($/MWh)
10	Life of Units
5	kWe per Unit effective output
95%	Capacity Factor
208,050	Annual Generation (KWh)
$ 0.035	O&M Cost ($/kWh)
6.0%	Loan/Bond Rate
13.0%	Loan/Bond Issuance Cost %
2.5%	Inflation
3.1%	Real Discont Rate
7.0%	Nominal Discount Rate
$ 0.1906	Average Utility Cost ($/kWh)
1.8%	Utility/Fuel Cost Escalator
20.59%	Expected incentives (% of cost)

LCOE Results

$0.1132	Nominal Levelized Cost $/KWh
$0.1181	Real Levelized Cost $/KWh
$942	Nominal Levelized Cost $/KW
$982	Real Levelized Cost $/KW

Break-Even Costs

$1,704	Nominal Levelized Cost $/KW
$1,713	Real Levelized Cost $/KW

Year	Annual Generation (kWh/Yr)	Annual Debt Service ($/Yr)	O&M Cost ($/Yr)	Fuel Cost ($/Yr)	Elec and Gas Net Savings $/yr	Total Cost ($/Yr)	Incentives ($/Yr)	Total Cost w/ Incentives ($/Yr)	Utility Cost ($/Yr)	Annual Debt Service ($/kWh)	O&M Cost ($/kWh)	Fuel Cost ($/kWh)	Total Cost ($/kWh)	Incentives ($/kWh)	Total Cost w/ Incentives ($/kWh)	Utility Cost ($/kWh)
2013	208,050	$34,928	$7,282	$13,715	$27,935	$27,990	$46,840	-$18,851	$39,654	$0.1679	$0.0350	$0.0659	$0.2688	$0.22514	$0.0437	$0.1906
2014	208,050	$34,928	$7,464	$13,961	$27,935	$28,419	$0	$28,419	$40,368	$0.1679	$0.0359	$0.0671	$0.2709	$0.00000	$0.2709	$0.1940
2015	208,050	$34,928	$7,650	$14,213	$27,935	$28,856	$0	$28,856	$41,095	$0.1679	$0.0368	$0.0683	$0.2730	$0.00000	$0.2730	$0.1975
2016	208,050	$34,928	$7,842	$14,469	$27,935	$29,304	$0	$29,304	$41,834	$0.1679	$0.0377	$0.0695	$0.2751	$0.00000	$0.2751	$0.2011
2017	208,050	$34,928	$8,038	$14,729	$27,935	$29,760	$0	$29,760	$42,587	$0.1679	$0.0386	$0.0708	$0.2773	$0.00000	$0.2773	$0.2047
2018	208,050	$34,928	$8,239	$14,994	$27,935	$30,226	$0	$30,226	$43,354	$0.1679	$0.0396	$0.0721	$0.2796	$0.00000	$0.2796	$0.2084
2019	208,050	$34,928	$8,445	$15,264	$27,935	$30,702	$0	$30,702	$44,134	$0.1679	$0.0406	$0.0734	$0.2818	$0.00000	$0.2818	$0.2121
2020	208,050	$34,928	$8,656	$15,539	$27,935	$31,188	$0	$31,188	$44,929	$0.1679	$0.0416	$0.0747	$0.2842	$0.00000	$0.2842	$0.2160
2021	208,050	$34,928	$8,872	$15,819	$27,935	$31,684	$0	$31,684	$45,738	$0.1679	$0.0426	$0.0760	$0.2866	$0.00000	$0.2866	$0.2198
2022	208,050	$34,928	$9,094	$16,103	$27,935	$32,190	$0	$32,190	$46,561	$0.1679	$0.0437	$0.0774	$0.2890	$0.00000	$0.2890	$0.2238

Appendix E

Case Study Applications

Appendix E

Case Study Applications

Case Study: 5 kW Combined Heat and Power Fuel Cell System

E.1 Case Study Inputs

The objective of this case study is to demonstrate micro-combined heat and power fuel cell systems (micro-CHP-FCS) in small commercial facilities and assess their performance to help determine and document market viability. This information is important for the U.S. Department of Energy (DOE), the fuel cell community, and most importantly for small commercial facilities that have operational power and heat requirements. Micro-CHP-FCSs for this demonstration were acquired through an open competition that ClearEdge Power won for its 5 kWe + 5.5 kWt high-temperature, PBI fuel cell. Between September 2011 and March 2012, ClearEdge Power installed 15 of their micro-CHP-FCSs for application and demonstration at four different deployment sites: two sites in Northern California, one site in Southern California, and one site in Oregon (for a sample deployment see Figure E.1). Table E.1 shows the list of site locations along with the unit numbers for each of the deployment sites. Although the case study used only one type of fuel cell available in today's market place, the results should be representative of the general trends typical of other micro-CHP-FCSs available in that range.

Figure E.1. Two Micro-CHP-FCS Units Tested for this Study in Portland, Oregon

Cost analyses of micro-CHP-FCS installations quantify their current and expected future profitability. Cost data gathered from the manufacturer include capital cost, additional equipment capital, installation, sales tax, and decommissioning costs, and the total cost of fuel over the lifetime of the project. All costs are recorded in present day dollars.

The total project cost for each site is also shown in Table E.1. Total project costs can be broken into four contributions: 1) DOE cost share, 2) the partner cost share, 3) federal tax credit cost share, and 4) state tax credit or rebate cost share. The Federal Business Energy Investment Tax Credit (ITC) provided a 30% credit of up to $3,000/kW of installed electrical capacity for fuel cell capital equipment and installation costs only [E.1]. Under the California Self-Generation Incentive Program, a cash rebate of up to $2,500/kW can be used when using a system fueled by natural gas for installations in California [E.2]. The DOE cost share varied from 36 to 44% depending on the location. The differences in cost per unit (DOE cost share) arise from the differences in additional equipment costs (vary depending on the infrastructure at a given site), variable sales tax, and fuel costs. On average, the cost of one Micro-CHP-FCS unit is approximately $83,500. Figure E.1 shows the average cost distribution among the micro-CHP-FCSs in the deployed fleet. The total cost breakdown is estimated as follows: 55% capital cost, 16% natural-gas fuel costs, 16% installation costs, and the remainder for additional equipment costs, unit decommissioning, and sales tax. The capital costs include an estimate for operating and maintenance (O&M) costs for replacement of the stack and balance-of-plant (BOP) components.

Table E.1. Total Project Costs and Cost Share Information for Individual Sites

Partner/Site	Location	Number of FCSs	Unit #	Total Project Cost [$]	DOE Cost Share [$]	DOE Cost Share [%]
College	Portland, Oregon	2	129 and 130	$188K	$82K	44%
Nursery	Corona Del Mar, California	3	131, 132, and 133	$228K	$83K	36%
Recreation	Oakland, California	5	137, 139, 140, 141, and 142	$409K	$150K	37%
Grocery	San Francisco, California	5	147, 153, 161, 162, and 163	$427K	$158K	37%
Total		**15**		**$1,252K**	**$473K**	**38%**

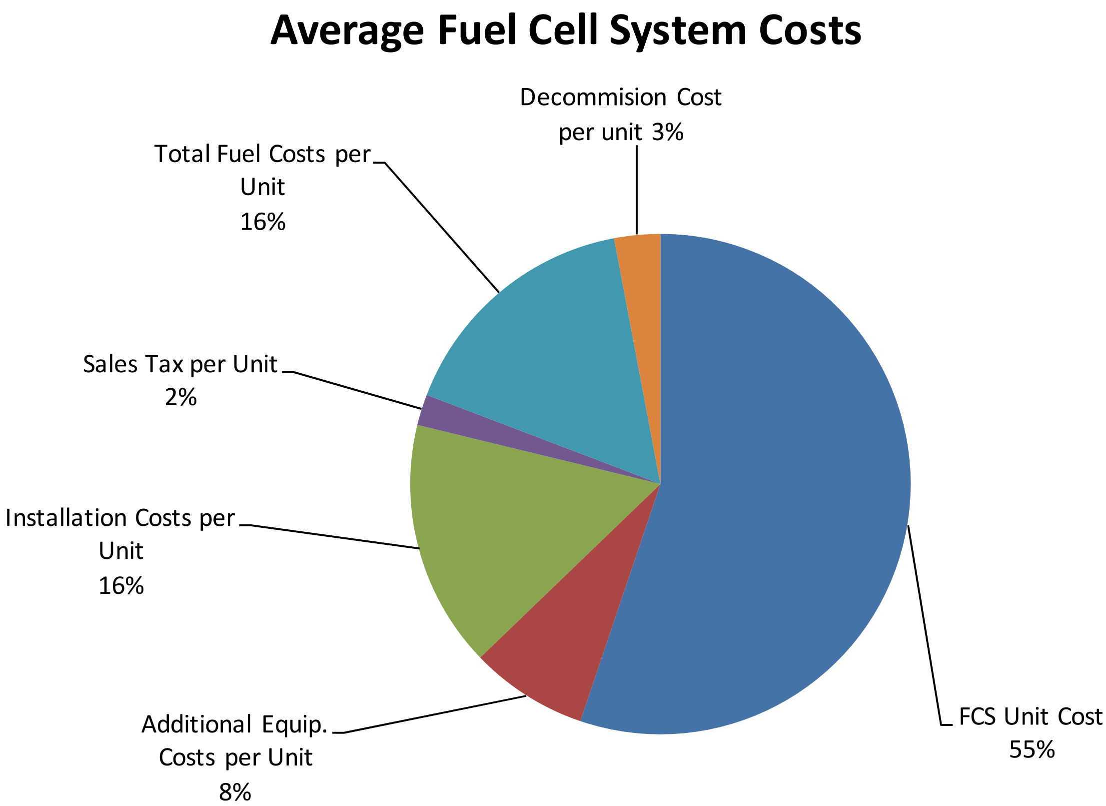

Figure E.2. Cost Distribution for an Average Micro-CHP-FCS in the Deployed Fleet

E.2 Baseline Results for Case Study

The micro-CHP-FCS units in the field now (deployed fleet) are 36 inches wide × 27 inches deep × 70 inches tall and require a 3 foot clearance on two sides. A typical micro-CHP-FCS unit is shown in Figure E.1. Table E.2 shows the system ratings for electrical/heat outputs and efficiencies. The financial analysis presented here is based on the rated performance data (5 kWe and 5.5 kWt) provided by the manufacturer.

Table E.2. Manufacturer Rating on System Outputs and Efficiencies

Average Net Electric Power Output [kWe]	Average Net Heat Recovery [kWt	Temperature to Site [°C]	Average Net System Electric Efficiency[a] [%]	Average Net Heat Recovery Efficiency[a] [%]	Overall Net System Efficiency[a] [%]
5.0	**5.5**	**up to 65**	**36**	**40**	**76**

(a) Efficiencies are based on higher heating value.

E.3 Average Cost of Power/Energy

The average per unit cost of power can be calculated by dividing the expected total project cost of an installation site by the total installed electrical power and/or heat recovery power at that site. Figure E.3 shows the average per unit cost of power. For the first set of bars in the chart, the y-axis is defined as the total project cost divided by the electrical power capacity of the installation. The installation sites have a cost per unit of installed electrical power capacity that ranges from $15,168/kWe to $18,833/kWe with an average value of $16,851/kWe. Because these data are calculated by dividing by the electrical output of the system, the values do not account for the fact that the systems also produce useful heat. As a result, these values may appear high when compared with non-CHP power plants.

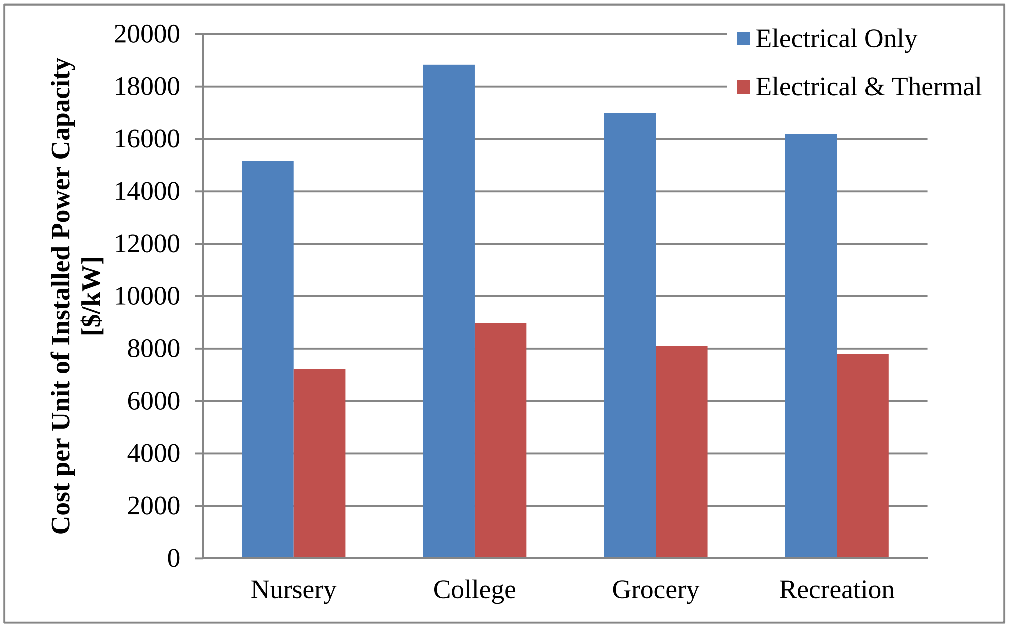

Figure E.3. Breakdown of Cost per Unit of Installed Electrical Power Capacity

The second set of bars in the chart account for the combined output of electrical and heat recovery power, illustrating that the average per unit cost of power is greatly reduced. This approach allows one to account for the electricity and heat production capabilities of the micro-CHP-FCSs. The y-axis in this case represents the cost per unit of combined installed electrical and heat recovery power. This metric may be more appropriate for CHP installations because it takes into account the value of the heat. For the four installation sites, the cost per unit of installed electrical and/or heat recovery power capacity ranges from $7,223/kW to $8,968/kW, with an average value of about $8,025/kW.

Figure E.4 shows the average levelized per unit cost of energy in $/kWh. Once again the first bars in the chart do not consider the value of the heat output. When only electricity is considered as a product of the micro-CHP-FCS, the cost for a unit of electrical energy is very high. It varies between $0.38/kWh to $0.48/kWh with an average value of $0.43/kWh.

The total cost per unit of installed electrical and heat recovery energy capacity in terms of $/kWh is also illustrated in Figure E.4. This parameter is valuable for cost comparisons, particularly with CHP systems. The y-axis for the second set of bars represents the cost per unit of combined installed electrical and heat recovery energy and it ranges from $0.18/kWh to $0.23/kWh with an average of $0.20/kWh.

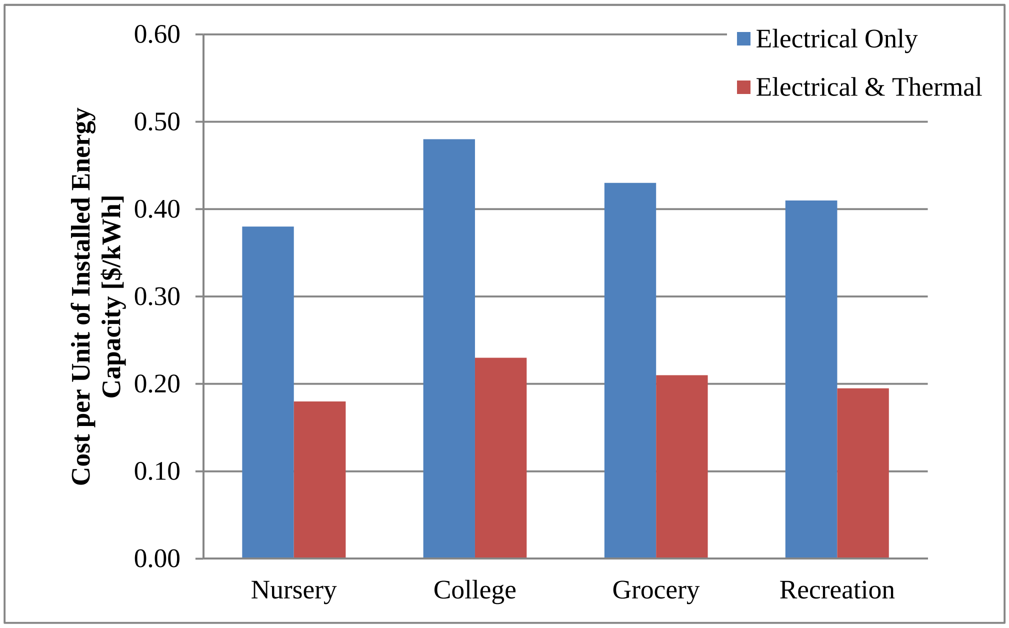

Figure E.4. Breakdown of the Levelized Cost per Unit of Installed Electrical Energy Capacity

E.4 Payback Calculations

The payback analysis performed here is based on the details of specific micro-CHP-FCS deployments. Additionally, the payback in this section includes up-front O&M costs as part of the capital costs (based on the project contract with the fuel cell system provider) and depreciation as part of the annual savings. This approach, although more complicated, is used to provide a more realistic value for payback. As with simple payback, this calculation divides the total costs by annual savings.

The total cost includes capital cost of the equipment, 5-year fuel costs in present day dollars, installation costs, additional equipment costs, decommissioning costs, and sales tax. The fuel cost is a variable cost and is incurred over the period of performance (5 years), and decommissioning cost is a one-time cost that will be incurred at the end of the period of performance. Because the period of performance for the deployed FCS units is 5 years, a 5-year warranty cost is incurred at the time of purchase and installation. The operating and maintenance costs that are covered by the warranty, including providing analysis data of the fuel cell performance, technical support, and any needed repairs are bundled together in the capital cost. All costs are recorded in present day dollars. The annual savings includes grid electricity and heating costs. The depreciation included in the annual savings is calculated using a straight-line approach, over 5 years, with a residual value of zero dollars. The depreciation tax rate was assumed to be 33%.Table E.3 also shows the projected cost and the desired cost payback calculations. The projected costs are based on an estimated production of 4000 systems/year. The individual breakdown of the projected costs is business sensitive and is not shown here. The total unit costs for the desired case were back calculated using a desired payback period of 3 years. For both the projected and the desired cases, grid costs were assumed to be the same as today.

E.5 Engineering Performance Analysis

Engineering performance parameters identified and used in the financial analysis were independently monitored and analyzed by Pacific Northwest National Laboratory (PNNL). This analysis led to several recommendations that resulted in system improvements and system upgrades. The analysis can be divided into three distinct time periods as described in the list below. The micro-CHP-FCS results for each these time periods are provided in Table E.4.

1. *Data analysis of as-installed micro-FCS units*. A total of 10 systems were installed between September and December 2011. Initial data indicated that the systems have a long-term average production of about 4.5 kWe of power. This was slightly below the manufacturer's stated rating of 5 kWe electric power output. Furthermore, the power output declined for all units over this time period. The rate of decline averaged over the fuel cells evaluated is near 0.16 kW per 1000 hours. This decline could be partly a result of high-temperature PBI degradation and/or fuel cell stack degradation.

2. *Data analysis after set-point changes*. Based on PNNL's recommendation, the system set point was changed from 5 kWe to 4 kWe for the near short term. Between March 2012 and June 2012, data analysis indicated that the fuel cells have relatively stable performance and a long-term average production of about 4.0 kWe of power. This value is consistent with the manufacturer's new set-point output of 4 kWe. However, there were some reliability issues that are manifested as decreased availability (88.9%). The project team attributed these to the BOP component failures. Based on this analysis and the initial analysis performed by PNNL, BOP component upgrades were made in late-June/early-July 2012.

3. *Data analysis after BOP upgrades*. BOP component upgrades for eight systems were done during June and July 2012. Data analysis indicated that the fuel cell systems have relatively stable performance and a long-term average production of about 4.0 kWe of power. Furthermore the reliability of the systems increased and is manifested as increased availability (94.4%).

Table E.3. Simple Payback Calculations of Specific Micro-CHP-FCS Deployments

Site	Array Size - Units	Fuel Cell System (FCS) Costs per Unit						Tax Incentives per FCS Unit				Grid Costs		Annual FCS Savings		Payback in Years	
		FCS Unit Cost	Additional Equipment Costs/Unit	Installation Costs/Unit	Sales Tax/Unit	Total Fuel Costs/Unit	Decom. Costs/ Unit	Federal	State/ Local	**Total Cost /Unit**	**Total Incentives /Unit**	Electricity	Heating	Savings Per Unit by Switching Away from Grid	Depreciation Savings per Unit per Year	**Without Incentives**	**With Incentives**
College	2	$46,500	$15,521	$18,998	$0	$10,648	$2,500	$0	$0	**$94,167**	**$0**	$0.077	$0.063	$6,425	$5,347	**8.66**	**8.66**
Nursery	3	$46,500	$2,850	$8,183	$2,131	$13,679	$2,500	$5,862	$12,500	**$75,842**	**$18,362**	$0.207	$0.048	$11,379	$3,938	**4.95**	**3.75**
Recreation	5	$46,500	$3,313	$10,727	$2,390	$16,286	$2,500	$6,131	$12,500	**$81,716**	**$18,631**	$0.207	$0.048	$11,379	$4,153	**5.32**	**4.06**
Grocery	5	$46,500	$3,998	$15,992	$2,208	$14,115	$2,500	$9,366	$12,500	**$85,313**	**$21,866**	$0.207	$0.048	$11,379	$4,534	**5.43**	**3.99**
Current Average →		**$46,500**	**$6,421**	**$13,475**	**$1,682**	**$13,682**	**$2,500**	**$5,340**	**$9,375**	**$84,259**	**$14,715**	**$0.175**	**$0.052**	**$10,141**	**$4,493**	**6.09**	**5.12**
Projected	1	-	-	-	-	-	-	-	-	**$63,201**	-	$0.207	$0.048	**$10,141**	**$3,268**	**4.71**	-
Desired	1	-	-	-	-	-	-	-	-	**$41,363**	-	$0.207	$0.048	**$10,141**	**$3,647**	**3.00**	-

Notes:

- Period of performance for the fuel cell system units is 5 years
- Fuel costs shown above represent a total 5 year fuel cost (period of performance) based on net present value.
- Decommissioning cost is the net present value estimate of the decommissioning cost at the end of period of performance - provided by ClearEdge Power
- Grid Costs are assumed to be constant over the period of performance
- Depreciation costs are calculated for the period of performance at a tax rate of 33%
- For payback periods greater than 5 years, the payback calculation was corrected to include the extra fuel costs incurred after 5 years
- For the "Projected," case, costs (individual break down is business sensitive and is not shown here) are based on an estimated production of 4000 systems/year - provided by the FCS supplier
- For the "Desired," case costs are back calculated for a payback period of 3 years

Table E.4. Micro-CHP-FCS Performance Summary

		Initial Data	After Set-Point Changes	After BOP Upgrades
	Stated Value	Oct. 2011 to Feb. 2012	Mar. 2012 to Jun. 2012	Jul. 2012 to Jan. 2013
Number of Operating Units	--	10	15	8
Average Net Electric Power Output (kWe)	5.0	4.4±0.3	4.0 ± 0.2	4.0 ± 0.2
Average Net Heat Recovery[(a)] (kWt)	5.5	5.1 ± 0.4	4.6 ± 0.2	4.5 ± 0.2
Temperature to Site (°C)	Up to 65	56.3 ± 3.8	49.6 ± 3.9	48.9 ± 5.2
Average Net System Electric Efficiency[(b)] (%)	36	33.0 ± 2.0	33.5 ± 2.5	33.8 ± 2.0
Average Net Heat Recovery Efficiency[(b)] (%)	40	37.4 ± 2.3	38.0 ± 2.8	38.4 ± 2.3
Overall Net System Efficiency[(b)] (%)	76	70.4 ± 4.4	71.6 ± 5.4	72.2 ± 4.3
Availability A_o (%)		95.7	88.9	94.4

a. The average heat recovery values are calculated by the manufacturer, and do not represent a measured value. Units 147, 153, 161, 162, and 163 were installed in March 2012.
b. Efficiencies are based on higher heating value.

E.5 Summary of the Progress and Next Steps

The current systems will be replaced with next-generation units (PureCell System Model 5). This should bring the economics of the fuel cells back to the analysis presented here and further improve the availability. The new product (PureCell System Model 5, was released starting in summer of 2013) is 62 inches wide × 36 inches deep × 88 inches tall with an integrated heat rejection module on top of the unit.

E.6 References

E.1. U.S. Fuel Cell Council. 2008. “Federal Fuel Cell Tax Incentives: An Investment in Clean Energy and Efficient Technologies.” Washington, D.C. Available at: http://www1.eere.energy.gov/hydrogenandfuelcells/education/pdfs/200810_itc.pdf.

E.2. Center for Sustainable Energy California. 2010. *Self-Generation Incentive Program Handbook*. San Francisco, California.

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