LBNL-6772E

ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

A Total Cost of Ownership Model for Low Temperature PEM Fuel Cells in Combined Heat and Power and Backup Power Applications

Max Wei, Timothy Lipman[1], Ahmad Mayyas[1], Joshua Chien[2], Shuk Han Chan[2], David Gosselin[2], Hanna Breunig, Michael Stadler, Thomas McKone, Paul Beattie[3], Patricia Chong[3], Whitney G. Colella[4], Brian D. James[4]

Environmental Energy Technologies Division
October 2014

[1]University of California, Berkeley, Transportation Sustainability Research Center, Berkeley, California
[2]University of California, Berkeley, Laboratory for Manufacturing and Sustainability, Department of Mechanical Engineering, Berkeley, California
[3]Ballard Power Systems
[4]Strategic Analysis, Inc. (SA), Energy Services Division, 4075 Wilson Blvd., Suite 200, Arlington VA 22203

This work was supported by the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy (EERE) Fuel Cells Technologies Office (FCTO) under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231

DISCLAIMER

ACKNOWLEDGEMENTS

The authors gratefully acknowledge the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy (EERE) Fuel Cells Technologies Office (FCTO) for their funding and support of this work.

The authors would like to express their sincere thanks to Mickey Oros from Altergy Power Systems, Bob Sandbank from Eurotech, Mark Miller from Coating Tech Services, Geoff Melicharek and Nicole Fenton from ConQuip, Inc., and Charlene Chang from Richest Group (Shanghai, China) for their assistance and valuable inputs.

Executive Summary

A total cost of ownership model (TCO) is described for emerging applications in stationary fuel cell systems. Low temperature proton exchange membrane (LT PEM) systems for use in combined heat and power applications from 1 to 250 kilowatts-electric (kWe[1]) and backup power applications from 1 to 50 kWe are considered. The total cost of ownership framework expands the direct manufacturing cost modeling framework of other studies to include operational costs and life-cycle impact assessment of possible ancillary financial benefits during operation and at end-of-life. These include credits for reduced emissions of global warming gases such as carbon dioxide (CO_2) and methane (CH_4), reductions in environmental and health externalities, and end-of-life recycling.

System designs and functional specifications for LT PEM fuel cell systems for back-up power and co-generation applications were developed across the range of system power levels above. Bottom-up cost estimates were made based on currently installed fuel cell systems for balance of plant (BOP) costs, and detailed evaluation of design-for-manufacturing-and-assembly[2] (DFMA) costs was carried out to estimate the direct manufacturing costs for key fuel cell stack components. The costs of the fuel processor subsystem are also based on a DFMA analysis (James et. al., 2012). The development of high throughput, automated processes achieving high yield are estimated to push the direct manufacturing cost per kWe for the fuel cell stack to nearly $200/kWe at high production volumes. Overall system costs including corporate markups and installation costs are about $1800/kWe ($1600/kWe) for 100kW (250kW) CHP systems at 50,000 systems per year, and about $1100/kWe for 10kWe backup power systems at 50,000 systems per year.

At high production volume, material costs dominate the cost of fuel cell stack manufacturing. Based on these stack costs, we find that BOP costs (including the fuel processor) dominate overall system direct costs for CHP systems and are thus a key area for further cost reduction. For CHP systems at low power, the fuel processing subsystem is the largest cost contributor of total non-stack costs. At high power, the electrical power subsystem is the dominant cost contributor. In this round of cost estimates, a DFMA analysis was not applied to the non-fuel processor balance of plant components and cost estimates were based on industrial price quotes. It is expected that a full DFMA analysis of the non-fuel processor balance of plant components could show a greater trend towards cost reduction with increase in production volume.

Life-cycle or use-phase modeling and life cycle impact assessment (LCIA) were carried out for a several building types (small hotels, hospitals, and small office buildings) in six U.S. cities. TCO costs of fuel cell CHP systems relative to grid power only exceed prevailing commercial power rates at the system sizes and production volumes studied here, except in regions in the U.S. with high-carbon intensity electricity from the grid. Including total cost of ownership credits can bring the levelized cost of electricity below the cost of electricity purchased from the grid in Minneapolis and Chicago. TCO costs for fuel cell CHP systems are dependent on several factors such as the cost of natural gas, utility tariff structure, amount of waste heat utilization, carbon intensity of displaced electricity and conventional heating, carbon price, and valuation of health and environmental externalities. Quantification of externality damages to the environment and public health utilized earlier environmental impact assessment work and datasets available at LBNL.

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[1] In this report, units of kWe stand for net kW electrical power unless otherwise noted.
[2] DFMA is a registered trademark of Boothroyd, Dewhurst, Inc. and is the combination of the design of manufacturing processes and design of assembly processes for ease of manufacturing and assembly and cost reduction.

Overall, this type of total cost of ownership analysis quantification is important to identify key opportunities for direct cost reduction, to fully value the costs and benefits of fuel cell systems in stationary applications, and to provide a more comprehensive context for future potential policies.

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Table of Abbreviations and Nomenclature

AC	alternating current
APEEP	Air Pollution Emission Experiments and Policy Analysis Model
AEF	average emission factor
BIP	bipolar plate
BOL	beginning of life
BOM	bill of material
BOP	balance of plant
BPP	bipolar plate
BU	backup
BUP	backup power
CEM	continuous emissions monitoring system
CCM	catalyst coated membrane
CEUS	California Commercial End-use Survey
CHP	combined heat and power
CO	carbon monoxide
DC	direct current
DER CAM	Distributed Energy Resources Customer Adoption Model
DFMA	Design for Manufacturing and Assembly
DG	distributed generation
DHW	domestic hot water
DI	de-ionizing
DOE	U.S. Department of Energy
DTI	DTI Energy Inc.
EOL	end of life
EPA	Environmental Protection Agency
ePTFE	expanded polytetrafluoroethylene
FC	fuel cell
FCS	fuel cell system
FEP	fluorinated ethylene propylene
FMEA	failure modes and effect analysis
FP	fuel processor
GDL	gas diffusion layer
GHG	greenhouse gas
GIS	geographic information system
GREET	Argonne National Laboratory's Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model
GWP	global warming potential
G&A	general and administrative expense
HDPE	high density polyethylene
HHV	higher heating value
HMI	human machine interface
HT	high temperature
IM	injection molding
IR	infrared

kWe	kilowatts of electricity
kWe	kilowatt-hours of electricity
LBNL	Lawrence-Berkeley National Laboratory
LCA	life cycle assessment
LCC	life cycle cost modeling
LCIA	life cycle impact assessment modeling
LHV	lower heating value
LMAS	Laboratory for Manufacturing and Assembly
LSCF	lanthanum-strontium-cobalt-ferrite
LT	low temperature
L-AEF	localized average emission factor
MCO	manganese cobalt oxide
MEA	membrane electrode assembly
MEF	marginal emission factor
Min	minutes
MRO	Midwest Reliability Organization
NERC	North American Electric Reliability Corporation
NG	natural gas
Ni-Co	nickel cobalt
Nm^3	normal cubic meters
NOx	nitrogen oxides
NREL	National Renewable Energy Laboratory
NSTF	nanostructured thin film
NSPC	Northern State Power Company
O&M	operation and maintenance
PEN	polyethylene naphthalate
PEM	proton exchange membrane
PFSA	perfluorinated sulfonic acid
PM	Particulate matter
PNNL	Pacific Northwest National Laboratory
ppmv	parts per million (by volume)
PROX	preferential oxidation
PTFE	polytetrafluoroethylene
Pt/Co/Mn	platinum-cobalt-manganese
PVD	physical vapor deposition
R&D	research and development expense
SMR	steam methane reformer
SOFC	solid oxide fuel cell
SR	steam reforming
TCO	total cost of ownership model
UTC	United Technologies Corporation
VOC	volatile organic compound
WECC	Western Electricity Coordinating Council
WGS	water gas shift

1 Introduction

As the world moves toward a more carbon constrained economy, a better understanding of the costs and benefits of "cleaner" technology options such as fuel cells are critically needed as industry and governments make research, development and deployment funding decisions and as organizations and individuals make long term investment decisions. Fuel cell systems are being considered for a range of stationary and specialty transport applications due to their ability to provide reliable power with cleaner direct emissions profiles than fossil fuel combustion-based systems. Existing and emerging applications include primary and backup power, combined heat and power (CHP), materials handling applications such as forklifts and palette trucks, and auxiliary power applications.

As a chemical energy conversion process, fuel cells have intrinsically higher efficiency and much lower criteria pollutant emissions than coal or gas combustion-based plants. Stationary applications are also less constrained to the weight and size limitations of vehicles. In addition, fuel cells can serve as a reliable source of base load power in comparison to intermittent wind or solar photo-voltaic supply sources. If fuel cells become widely available they could displace coal plants and improve public health outcomes due to the elimination of coal-fired air pollutants such as fine particulate matter, and they might also displace nuclear plants and avert the disposal issues associated with nuclear waste. Fuel cell systems also can qualify as distributed generation systems and as power supply sources close to load, they do not trigger transmission line construction or line losses. Natural gas supplied fuel cell systems result in lower overall CO_2-equivalent emissions than the average U.S. grid emissions.

Over the last decade, the Department of Energy (DOE) has supported several cost analysis studies for fuel cell systems for both automotive (James 2010, Sinha 2010) and non-automotive systems (Mahadevan 2010, James 2012). While many cost studies and cost projections as a function of manufacturing volume have been done for specific fuel cell stack technologies and for automotive fuel cell systems (Sinha 2010), fewer cost studies have been done for stationary fuel cell applications. The limited studies available have primarily focused on the manufacturing costs associated with fuel cell system production. This project expands the scope and modeling capability from existing direct manufacturing cost modeling in order to quantify more fully the broader economic benefits of fuel cell systems by taking into account life cycle assessment, air pollutant impacts and policy incentives. The full value of fuel cell systems cannot be captured without considering the full range of Total Cost of Ownership (TCO) factors. TCO modeling becomes important in a carbon-constrained economy and in a context where health and environmental impacts are increasingly valued.

This report provides TCO estimates starting with the direct manufacturing cost modeling results for CHP systems in the 1 to 250 kWe range and for backup power systems in the 1 to 50 kWe range for low temperature proton exchange membrane-based (LT PEM) systems (Table 1.1), including a detailed breakdown of fuel cell stack, balance-of-plant, and fuel subsystem component costs. CHP systems assume reformate fuel and backup power systems assume direct H_2 fuel. Life-cycle costs of CHP systems are estimated for various commercial buildings in different geographical regions of the U.S. Health and environmental impact assessment is provided for fuel cell-based CHP systems compared to a baseline of grid-based electricity and fossil fuel-based heating (e.g., natural gas, fuel oil, wood, etc., or some combination thereof). This is not meant to be a market penetration study, although promising CHP market regions of the country are identified. Rather, the overriding context is to assume that this market is available to fuel cell systems and to address what range of costs can be achieved and under what assumptions.

APPLICATION	SIZE [KW]	PRODUCTION VOLUME (UNITS/YEAR)			
		100	1000	10,000	50,000
Combined Heat and Power (CHP)	1	x	x	x	x
	10	x	x	x	x
	50	x	x	x	x
	100	x	x	x	x
	250	x	x	x	x

APPLICATION	SIZE [KW]	PRODUCTION VOLUME (UNITS/YEAR)			
		100	1000	10,000	50,000
BACKUP POWER	1	x	x	x	x
	10	x	x	x	x
	25	x	x	x	x
	50	x	x	x	x

Table 1.1. Application space for this work. CHP and backup power are studied at various production volumes and system sizes.

Detailed cost studies provide the basis for estimating cost sensitivities to stack components, materials, and balance-of-plant components and identify key cost component limiters such as platinum loading. Other key outputs of this effort are manufacturing cost sensitivities as a function of system size and annual manufacturing volume. Such studies can help to validate DOE fuel cell system cost targets or highlight key requirements for DOE targets to be met. Insights gained from this study can be applied toward the development of lower cost, higher volume-manufacturing processes that can meet DOE combined heat and power system equipment cost targets.

1.1 Technical Targets and Technical Barriers

For stationary applications, DOE has set several fuel cell system cost and performance targets[3]. For example, for residential combined heat and power in the 10 kWe size, equipment cost in 2020 should be below $1700/kWe, electrical generation efficiency of greater than 45%, durability in excess of 60,000 hours and system availability at 99%. A summary of equipment cost targets for natural gas based systems is shown in Table 1.2. Note that the targets in Table 1.2 are for equipment costs but do not include installation costs.

System Type	2015 Target	2020 Target
10 kWe CHP System	$1900/kWe	$1700/kWe
100-250 kWe, CHP System	$2300/kWe	$1000/kWe

Table 1.2. DOE Multiyear plan system equipment cost targets for 10 kWe and 100-250 kWe system sizes for 2015 and 2020.

Stationary fuel cell systems are not deployed in high volumes today due to their still high initial capital costs, lack of familiarity, concerns with hydrogen as a fuel source, and other new technology adoption barriers. Among the identified barriers to more rapid deployment of fuel cells are:

- Reservations about new technology
- Concerns about suppliers,

3 http://energy.gov/eere/fuelcells/downloads/fuel-cell-technologies-office-multi-year-research-development-and-16, Section 3.4 Fuel Cells and Section 3.5 Manufacturing R&D

- Administration/transactional costs
- Demonstration of long-lifetime systems needed for power applications
- Uncertain/unproven reliability can make cost planning difficult – e.g., outages can trigger electricity demand charges in addition to fuel cell capital costs.
- Unfamiliar with working with H_2 in the case of backup power or forklifts

These barriers make clear the need for an increased understanding of the cost of fuel cell systems, especially in emerging applications with increasing manufacturing volumes.
This project further addresses the several technical barriers from the Technical Plan - Fuel Cells and Technical Plan - Manufacturing sections of the Fuel Cell Technologies Program Multi-Year Research, Development and Demonstration Plan (MYPP), including:

- Fuel-cell cost: Expansion of cost envelope to total cost of ownership including full life cycle costs and externalities
- Lack of High-Volume Membrane Electrode Assembly Processes
- Lack of High-Speed Bipolar Plate Manufacturing Processes

1.2 Emerging applications

The key markets for this study are combined heat and power applications, and backup power installations. Cost, system reliability and system utilization are key drivers. A recent report from Oak Ridge National Laboratory (Greene 2011) reports technology progress ratio data with a doubling of fuel cell output production in megawatts leading to 20-30% cost reduction. Recent studies have highlighted backup power systems and material handling systems as key market opportunities (Greene 2011, Mahadevan 2007). Depending on energy costs and policy environments, there may be opportunities for micro-CHP as well, for example in large expensive homes in cold climates. Cogeneration of power and heat for commercial buildings may be another opportunity, and has been highlighted as a market opportunity for California commercial buildings by Stadler 2011. Some buildings may have requirements greater than 250 kWe but these could be served by several fuel cell units of less than or equal to 250 kWe.
Internationally, stationary fuel cell systems are enjoying an increase in interest with programs in Japan, South Korea and Germany but all markets are still at a cost disadvantage compared to incumbent technologies. Japan has supported residential fuel cell systems of 0.7-1 kWe for co-generation with generous subsidies and the recent nuclear reactor accident in Fukishima has prompted consideration of a range of hydrogen powered systems as alternatives to nuclear energy.

1.3 Total Cost of Ownership Modeling

This work estimates the total cost of ownership (TCO) for emerging fuel cell systems manufactured for stationary applications. The TCO model includes manufacturing costs, operations and end of life disposition, life cycle impacts, and externality costs and benefits. Other software tools employed include commercially available Boothroyd Dewhurst DFMA software, existing LCA database tools, and LBNL exposure and health impact models. The overall research and modeling approach is shown in Figure 1.1.
The approach for direct manufacturing costs is to utilize Design for Manufacturing and Assembly (DFMA) techniques to generate system design, materials and manufacturing flow for lowest manufacturing cost and total cost of ownership. System designs and component costs are developed and refined based on the following: (1) existing cost studies where applicable; (2) literature and patent sources; (3) industry and national laboratory advisors.

Life-cycle or use-phase cost modeling utilizes existing characterization of commercial building electricity and heating demand by geographical region, and references earlier CHP modeling work by one of the authors (Lipman 2004). Life cycle impact assessment is focused on use-phase impacts from energy use, carbon emissions and pollutant emissions (Van Rooijen 2006) —specifically on particulate matter (PM) emissions since PM is the dominant contributor to life-cycle health impacts (NRC 2010). Health impact from PM is characterized using existing health impact models (Muller and Mendelsohn 2007) available at LBNL. Life-cycle impact assessment is characterized as a function of fuel cell system adoption by building type and geographic location. This approach allows the quantification of externalities (e.g. CO_2 and particulate matter) for FC system market adoption in various regions of the U.S.

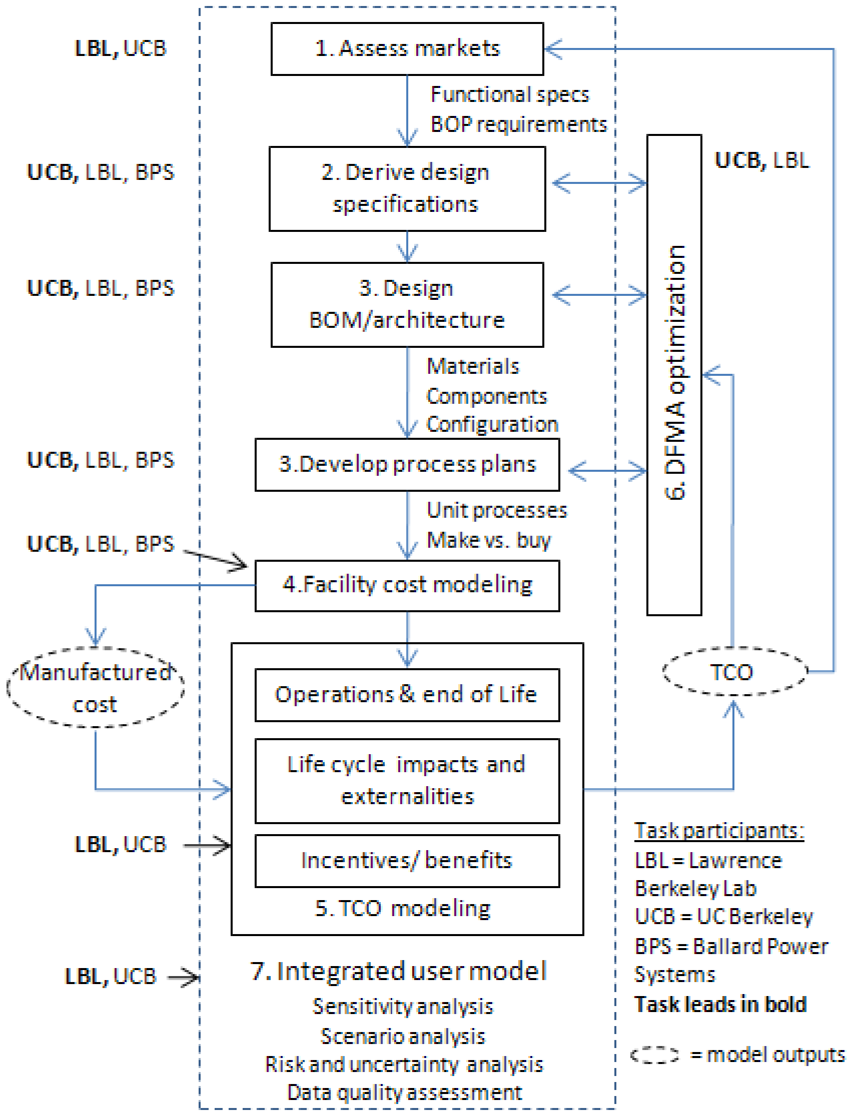


Figure 1.1. Research and modeling approach. (UCB= University of California, Berkeley, LBL = Lawrence Berkeley Laboratory, BPS = Ballard Power Systems, BOM=bill of materials, BOP = balance of plant, TCO=total cost of ownership)

2 Functional Requirements and System Designs

For this project, LT PEM FC system designs and functional specifications have been developed for a range of systems sizes including (1) CHP systems with reformate fuel[4] from 1-250 kWe, and (2) backup power systems from 1-50 kWe utilizing direct H_2 fuel. These choices are based upon a search of relevant fuel cell literature and patents, industry system spec sheets as well as industry advisor input. A key reference point for the CHP system design and functional specs is the 1.1 MW installation of a Ballard Power Systems ClearGen® Multi-MW System using direct H_2 fuel in Torrance, California made up of two 550 kWe systems. This system was carefully analyzed and conceptually downsized for applicability to the fuel cell system sizes in this report.[5]

The choice of these system designs and functional specifications allowed the research team to define the operational parameters for each respective fuel cell system and to define the system components or balance of plant (BOP) that will be the basis for cost estimates. Functional requirements for the stack further define the stack geometries and stack sizing (number of cells per stack) for the DFMA direct manufacturing cost analysis below. For CHP systems the functional specs for the stack represent beginning of life (BOL) performance, and stack degradation after approximate stack lifetime of 20,000 hours are accounted for by oversizing the stack by about 10% and de-rating the BOL current to account for EOL voltage degradation and power fade (e.g., approximately 10% voltage loss at the same current). This de-rating is not done for backup power systems and stack degradation is implicitly assumed as part of the stack lifetime (approximately 3000 hours in the near-term). The functional specifications also refer to the rated power of the system. Operating at partial load would result in slightly higher efficiency across most of the turndown ratio of the system.

System designs are meant to be "medium fidelity" designs that are representative of actual fuel cell systems to provide the basis for the costing estimates that are the main focus of this work. As such, the project is not scoped with process modeling or optimization of the system design in terms of detailed pressure management, flow rates, or detailed thermal balances. However, the designs are a reasonable starting points for costing based on feedback from industry advisors and for showing key system components, sub-systems, and interconnections that are important for understanding system "topography" for analysis and costing purposes.

2.1 System and Component Lifetimes

System and component lifetime assumptions are shown in Table 2.1 and 2.2 for CHP and backup applications, respectively. These specifications are shared across the system power range for each application. In the application of TCO to a CHP system, overall system life is assumed to be approximately 15 years currently and anticipated to increase to 20 years in the future (2015-2020 timeframe). Stack life is 20,000 hours in the near term and projected to double to 40,000 hours per industry and DOE targets. Subsystem component lifetimes vary from 5-10 years, with somewhat longer lifetimes expected in the future compared with the present.

The system turndown ratio is defined as the ratio of the system peak power to its lowest practical operating point (e.g., running at 33 kWe on a 100 kWe system is a turndown ratio of 3 to 1). The

[4] Functional specifications for CHP systems with direct H_2 fuel from 1-250 kWe were also developed but the focus of this work for CHP is systems with reformate fuel because of the wide availability of natural gas as an input fuel.
[5] This scaling down of a 550kWe system is expected to be more accurate for the larger sized CHP systems (i.e., 100 and 250kW systems) studied here. For 1-10kWe CHP systems, there are fewer LT PEM systems in the field, and the team also examined 2-10kWe backup power systems for reference. The system design and integration of lower power CHP systems (1kW range) is an area for follow up investigation, e.g., with Japanese vendors of micro-CHP systems.

stack cooling strategy for all CHP systems is assumed to be liquid water circulation, consistent with CHP system duty cycles and stack lifetime requirements.

Overall system and BOP subsystem lifetimes are similar for backup power applications (Table 2.2) but backup power stack design life is assumed to be 3000-5000 hours. In the backup power case, however, a direct air cooling strategy is utilized for stack cooling for cost savings and BOP design simplification.

CHP Application - PEM	**Near-Term**	**Future (2015-2020)**	**Units**
System life	15	20	years
Stack life	20,000	40,000	hours
Reformer life (if app.)	5	10	years
Compressor/blower life	7.5	10	years
Water Management subsystem life	7.5	10	years
Battery/startup system life	7.5	10	years
Turndown Ratio	3 to 1	3 to 1	ratio
Expected Availability	96	98	percent
Stack cooling strategy	Liquid	Liquid	cooling

Table 2.1. CHP application common specifications.

Backup Application	**Near-Term**	**Future**	Units
System life	15	20	years
Stack life	3,000	5000	hours
Compressor/blower life	8	10	years
Battery/startup system life	5	10	years
Turndown Ratio	3 to 1	3 to 1	ratio
Expected Availability	100	100	percent
Stack cooling strategy	Air	Air	cooling

Table 2.2. Backup power application common specifications.

2.1.1 CHP System Designs

A system design for an LT PEM fuel cell CHP systems operating on reformate fuel is shown in Figure 2.1. Delineation into subsystems is provided for modularity of design and also to facilitate the tracking and classification of balance of plant components and costing. The CHP systems are subdivided further into subsystems as follows: (1) fuel cell stack, (2) fuel supply system, (3) air supply, (4) water makeup loop, (5) coolant system, (6) power conditioning, (7) controls and meters, and (8) ventilation air supply.

To improve fuel utilization the CHP system with reformate fuel has a fuel burner to utilize anode tail gas fuel and also includes an air slip input (approximately 2% concentration) for greater CO tolerance, and larger stack sizing (about 10% more cells per stack) compared to the direct H_2 fuel case due to lower average stack electrical efficiency (Murthy et al., 2002). Note that in some cases where there is not a steady demand for waste heat, there may need to be additional parasitic fans and radiators to dissipate the waste heat.

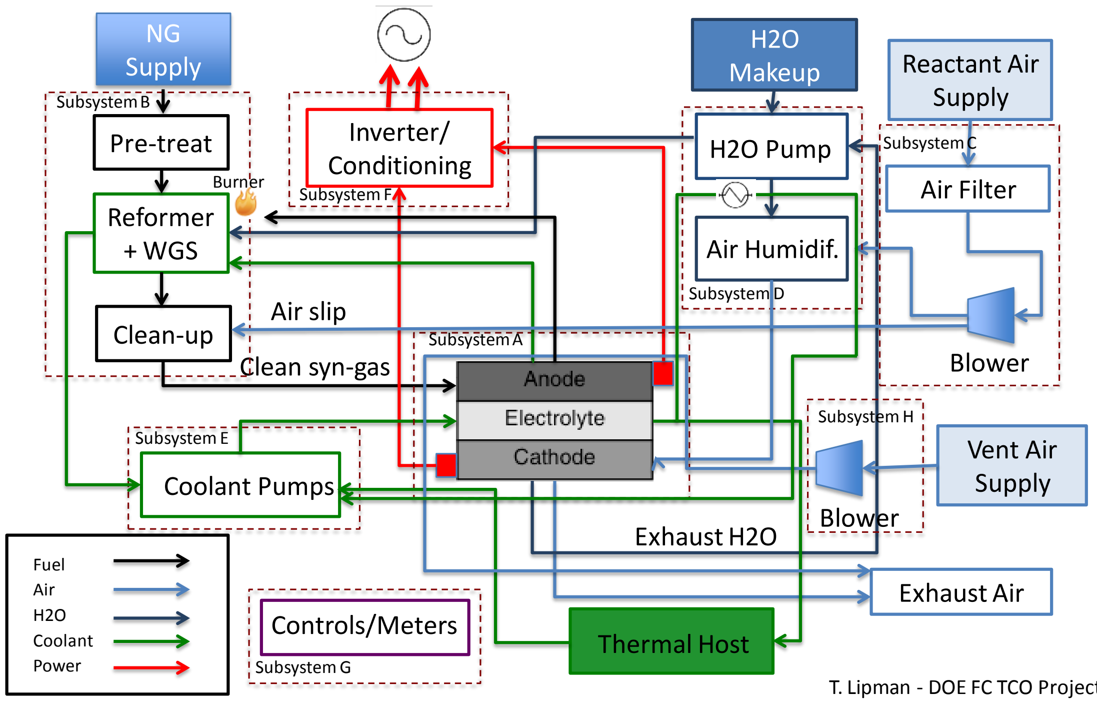


Figure 2.1. System design for CHP system using reformate fuel.

2.1.2 CHP Functional Specifications

Functional specifications for the 10 kWe and 100 kWe CHP systems with reformate fuel are shown in Table 2.3 below. These functional specifications were developed based on a variety of industry sources and literature and include calculated parameters for stack and system efficiencies for an “internally consistent” set of reference values.

The 10kW and 100kW sizes are established as base cases and functional specifications for additional 1, 50, and 250 kWe cases are found in Appendix A. A detailed description of the functional specification focused on the 10 kWe and100 kWe system sizes follows below.

The determination of gross system power reflects about 28% overall parasitic power at 10 kWe and about 24% at 100 kWe, including losses through the inverter. DC to AC inverter efficiency is assumed to be 93% and constant across the system power ranges. Additional parasitic losses are from compressors, blowers and other parasitic loads and are assumed to be direct DC power losses from the fuel cell stack output power.

Parameter	CHP System with Reformate Fuel , 10 kWe	CHP System with Reformate Fuel , 100 kWe	Unit
Gross system power	12.8	124	kWe
Net system power	10	100	kWe
Electrical output	480V AC	480V AC	Volts AC or DC
DC/AC inverter efficiency	93	93	%
Waste heat grade	65	65	Temp. °C
Reformer Efficiency	75	75	%
Fuel utilization, overall	90-95	90-95	%
Net electrical efficiency	32	33	% LHV
Thermal efficiency	49	50	% LHV
Total efficiency	81	83	Elect.+thermal (%)
Stack power	12.8	9.5	kWe
Total plate area	360	360	cm2
CCM coated area	259	259	cm2
Single cell active area	220	220	cm2
Gross cell inactive area	39	39	%
Cell amps	111	111	A
Current density	0.5	0.51	A/cm2
Reference voltage	0.7	0.7	V
Power density	0.35	0.35	W/cm2
Single cell power	77.8	77.9	W
Cells per stack	164	122	Cells
Stacks per system	1	13	Stacks
Parasitic Loss	2	16	kWe

Table 2.3. Functional specifications for CHP fuel cell system operating on reformate fuel

The waste heat grade from the coolant system is taken to be 65^{0}C for all system sizes although a range of other temperatures are possible, mostly over the range of 50-70^{0}C. The heat exchanger configuration can also depend on the demand temperatures for the heating streams, and the exact cooling and heating loops will be location and system specific. In the use-phase cost model described later in the report, hot water is generated as the main waste heat application with enhancement to space heating as an additional possibility. In the reformate fuel case, additional waste heat streams from the anode and cathode exhaust can be routed to the fuel processor reactor burner.

Overall fuel utilization is assumed to be up to 95% for reformate fuel systems with a "single pass" fuel utilization of 80%. This assumes that there is a fuel after-burner in the reformate case. At the reference cell voltage of 0.7 volts, the net electrical efficiency is 32-33% (LHV) for the reformate systems. These overall electrical efficiency levels are similar to those reported in the literature (e.g., see Nishizaki and Hirai, 2009). Fuel reformer efficiency is estimated to be 75%. The total overall efficiency of 81-83% is viewed as a benchmark value for the case where a large reservoir of heat demand exists and represents the maximal total efficiency of the system. Actual waste heat utilization and total efficiency will be highly dependent on the site and heating demands. For example, a smaller overall heat efficiency can result if waste heat utilization is confined to building water heating and the building has a relatively low demand for hot water. There is a well-documented tradeoff of peak power and efficiency. The functional specifications are defined for operation at full rated power. Moving away from the peak power point to lower current density, the cell voltage increases and thus the stack efficiency improves. Partial load operation has higher efficiency but less power output. For the LT PEM technology considered here, the system is assumed to be load following, or capable of ramping its power level up and down to follow electrical demand (to the turndown limit described in Table 2.1 above). This system flexibility is an advantage for LT PEM over higher temperature fuel cell systems and will be included in the use-phase modeling described later in the report.

2.1.3 CHP Stack Sizing

Total fuel cell plate area is taken to be 363 cm^2 based on inferences and interpretation of publically available industry spec sheets.[6] Catalyst-coated membrane area is about 72% of this area due to plate border regions and manifold openings. Single cell active area has an additional 15% area loss. As described further in the DFMA costing section below, this is due to the overlap and alignment area loss associated with the frame sealing process. The tradeoff here is a longer anticipated frame lifetime (20,000 hours) and higher reliability from this frame sealing process for continuous power applications versus the lower area loss with an alternative edge sealing process.

2.1.4 Backup Power System Design

The Backup Power system design (Figure 2.3) achieves cost reduction through simplification of balance of plant components with air-cooled system design and once-through H_2 fuel supply. Since the load for backup power is assumed to be DC power, there is a DC to DC power converter instead of a DC to AC inverter.

[6] All functional specifications (e.g,, gross and net system power, cell sizes, stack current density, etc.) are based on inferences and interpretations of publically available data, patents and literature by members of the research team from LBNL and UC-Berkeley and should not be interpreted as actual product data from Ballard Power, Altergy Systems, or any other fuel cell stack or component vendors.

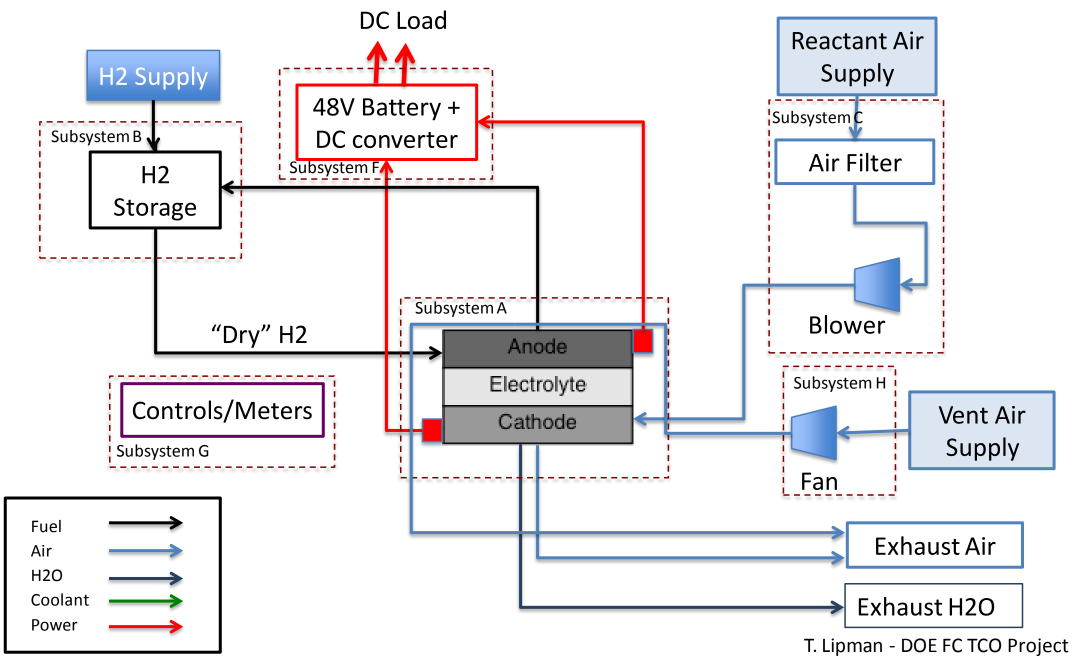


Figure 2.3. Schematic of 10 kWe Backup Power System Design.

2.1.5 Backup Power System Functional Specifications

In backup power applications, overall fuel utilization is assumed to be 95% with direct H_2 fuel, for a net electrical efficiency of 48%. Lower cell performance is assumed compared with the CHP stack (Table 2.4). Lower total catalyst loading is assumed at 0.3mg/cm^2 vs 0.5mg/cm^2 for the CHP case, with the same membrane thickness and catalyst deposition process as for the CHP system. Additionally, a stack air cooling strategy constrains the power density and reduces the current density. Gross cell inactive area is lower for the BU power case due to less manifold area required because of air cooling, and higher ratio of CCM active area to CCM coated area due to lower lifetime requirement for the backup power application.

Parameter	Backup Power, 1 kWe	Backup Power, 10 kWe	Backup Power, 50 ekWe	Unit
Gross system power	1.04	10.4	52	kWe
Net system power	1	10	50	kWe
Electrical output	24V DC	48V DC	48V DC	Volts AC or DC
DC/DC converter effic.	97%	97%	97%	%
Fuel utilization	95	95	95	%
Net Electrical efficiency	48%	48%	48%	% LHV
Total efficiency	48%	48%	48%	Elect.+thermal (%)
Stack power	1.04	10.4	7.44	kWe
Total plate area	363	363	363	cm^2
CCM coated area	306	306	306	cm^2
Single cell active area	285	285	285	cm^2
Gross cell inactive area	21	21	21	%
Cell amps	114	118	119	A
Current density	0.4	0.41	0.42	A/cm^2
Reference voltage	0.65	0.65	0.065	V
Power density	0.26	0.27	0.27	W/cm^2
Single cell power	74	77	77	W
Cells per stack	14	136	96	Cells
Stacks per system	1	1	7	Stacks
Parasitic Loss	0.01	0.1	5	kWe

Table 2.4. Functional specifications for backup power systems with direct H_2 fuel.

3 Costing Approach and Considerations

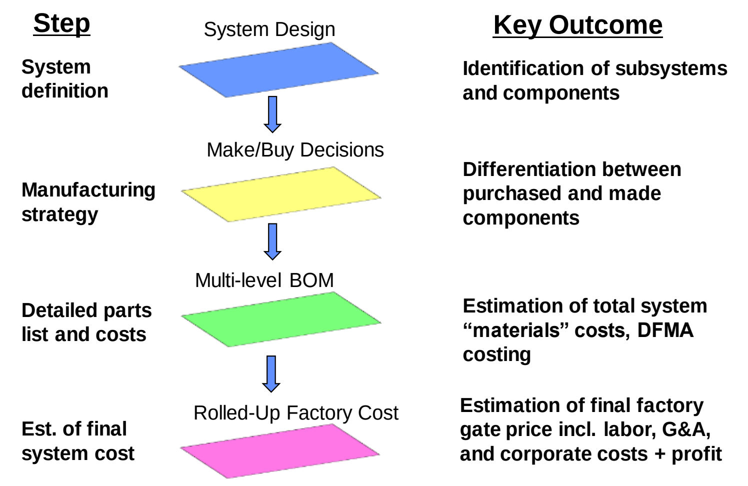
Here we describe the overall costing approach and its underlying inputs and assumptions. Figure 3.1(a) below provides a high level description of the costing approach. The starting point is system definition and identification of key subsystems and components following the approach in Chapter 2. Manufacturing strategy is then defined to determine which components to purchase and which to manufacture in-house. A detailed parts list is assembled for purchased components and detailed DFMA costing is done for in-house manufactured components. Direct manufacturing costs are captured in the DFMA costing, but a further markup will include non-manufacturing costs such as General and Administrative, Sales and Marketing, and profit margin to determine the final "factory gate" price to the customer.

The general guidelines for purchased-versus-made components or "make vs. buy" are whether the part is readily available as a commodity item or off-the-shelf part. If this is the case, there is little reason to manufacture in-house (e.g. pumps, compressors, electronic components). One informal criterion for purchasing components is whether or not there is an "active market" of buyers and sellers for the component. For example an active market might be defined as one in which there are at least three suppliers and three purchasers, and one in which suppliers do not have undue market power or monopoly power. Clearly there are gray areas where there may be off-the-shelf components available but a high degree of manual assembly is required, and the development of subassemblies available for purchase would more economical. These would probably require more standardized designs or interfaces for both the supplier industry and fuel cell system providers to leverage over time. Similarly, in many cases, a fuel cell supplier will find it cost effective to subcontract the design, manufacturing and/or assembly of a subsystem component to an appropriate manufacturing partner. Development of fuel processor components may follow this model. In this work we take a more simplified approach of "made vs. bought" components, but these considerations do enter into our cost estimates. For example, labor associated with system assembly is assumed to drop with increasing volume with both learning-by-doing and the implicit assumption that there is greater availability of subassemblies.

In our analysis, balance of plant components are largely assumed to be purchased components, and stack components are largely manufactured in-house, with carbon fiber paper and Nafion® membrane the key exceptions for reasons as described below. Vertical integration is assumed for stack manufacturing, i.e. a fuel cell manufacturer is assumed to manufacture all stack components as described below. This assumption is geared toward the case of high volume production. At lower production volume some purchase of finished or partially finished stack components may be cost beneficial because at very low volumes the investment costs for vertical integration is prohibitive and equipment utilization is inefficient.

The DFMA analysis includes the following items shown in Figure 3.1(b) for direct manufacturing costs, global cost assumptions and other non-product costs. For each manufactured component, first a patent and literature search was done and industry advisor input elicited, followed by selection of a base manufacturing process flow based on these inputs, an assessment of current industry tooling and direction, and engineering judgment as to which process flows can support high volume manufacturing in the future.

Direct manufacturing costs include capital costs, labor, materials, yield loss and factory building costs, subject to global assumptions such as discount rate, inflation rate and tool lifetimes. Our



(a)

Direct Manufacturing Costs

Capital costs
Labor costs
Materials costs
Consumables
Scrap / yield losses
Factory costs
Global Assumptions
Discount rate, inflation rate
Tool lifetimes
Costs of energy, etc.

Other Costs

R&D costs, G&A, sales, marketing
Product warranty costs

(b)

Figure 3.1 (a) Generalized roll-up steps for total system cost; (b) scope of direct manufacturing costs for components produced in-house.

methodology follows other cost studies (James 2012). For each major processing module (e.g. injection molding, or a catalyst coating step), a machine rate is computed corresponding to an annual production volume, where the machine rate comprises capital, operational and building costs and has units of cost per hour for operating a given module. “Process cost” per module is then the product of machine rate and annual operation hours of the tool. Total annualized manufacturing cost is the sum of process cost per module plus required labor and required materials and consumable materials.

Overall manufacturing costs are then quoted as the sum of all module or component costs normalized to the overall production volume in kWe. Direct manufacturing costs are quoted in cost per kWe of production, or, cost per meter squared of material can be quoted similarly for roll-to-roll goods such as GDL and catalyst coated membrane. Other costs such as G&A and sales and marketing are added to make up the final factory gate price.

3.1 Non-Product Costs

The DFMA cost estimates in Chapter 4 below refer to direct manufacturing costs and exclude profit, research and development (R&D) costs, and other corporate costs (sales and marketing, general and administrative, warranty, etc.).

To better quantify these other non-product costs, financial statements from four publicly traded fuel cell companies were analyzed for the 2008-2011 period (Fuel Cell Energy, Proton Power, Plug Power, and Ballard). Excluding Plug Power, which showed much higher non-product costs than the other companies, median General and Administrative (G&A) and Sales and Marketing costs were 40% of the Cost of Product and Services, and median R&D costs at 38% of Cost of Product and Services. Based on publically available financial statements, gross margins were 20% for Ballard but negative for the other three companies. All four recorded a net loss for all years in this period.

Thus a 100% markup in the sales price of a fuel cell system above the manufacturing cost would achieve a slightly positive operating income taking both G&A/Sales and Marketing, and R&D into account. These historical numbers for Sales and Marketing and R&D could be on the high side since these companies are building a market presence and these costs can be expected to drop over time with greater market penetration. A typical sales markup of 50% is expected to approximately cover the G&A/Sales portion of operating expenses for current fuel cell vendors but not R&D expenses. Government policies or incentives could possibly mitigate the R&D expenses portion in some years. Gross margin product markup is also expected to be extremely slim given the existence of highly cost competitive alternative technologies for CHP and backup power applications and borne out by the financial data above. These other factors can be seen to increase the direct manufacturing costs by 50% to 100% including profit margin and can be taken as a sensitivity factor in the use-phase model chapter.

3.2 Manufacturing Cost Analysis - Shared Parameters

Shared parameters for the cost analysis are summarized below. Tables 3.1 and 3.2 show the cell and stack configurations for CHP and backup power system based on the functional specifications described above. The number of cells per system will be used to compute total active area and component volumes in the DFMA section below. Similarly, the plate area and CCM coated area are shown in Table 3.3 and these cell area sizes are assumed to be the same for both CHP and backup power applications. These cell areas could be expected to change for different applications for optimized product configuration and performance, but at the same time, it is beneficial for manufacturing cost control to have a consolidated cell size in multiple products and that approach was taken here.

System Power [kWe]	Cells/stack	Stacks	Cells/system	Single cell power [W]	Gross Power [kWe]
1	14	1	14	74.4	1.04
10	136	1	136	76.5	10.4
50	96	7	672	77.5	52.1

Table 3.1. Summary of cell and stack configurations for Backup power systems with direct H_2 fuel. The number of cells per system is used to compute total active area and component volumes in the DFMA section below.

System Power [kWe]	Cells/stack	Stacks	Cells/system	Single cell power [W]	Gross Power [kWe]
1	17	1	17	77.8	1.3
10	164	1	164	77.8	12.8
50	136	6	816	77.5	63.3
100	122	13	1586	77.9	123.5
250	120	33	3960	78.0	308.8

Table 3.2. Summary of cell and stack configuration for CHP systems with reformate fuel. The number of cells per system is used to compute active areas and component volumes in the DFMA section below.

Parameter	CHP	Backup Power	Unit
Total plate area	363	363	cm^2
CCM coated area	259	306	cm^2
CCM active area	220	285	cm^2

Table 3.3. Plate and CCM coated area for CHP and backup power applications. The former is an input for calculations of plate manufacturing costs and the latter for the GDL and CCM costing analysis.

Parameter	Symbol	Value	Units	Comments
Operating hours	t_{hs}	varies	Hours	8 hours base shift; [1,1.5,2] shifts
Annual Operating Days	t_{dy}	250	Days	52wks*5days/wk-10 vacation days
Production Availability	A_m	0.85		Typical value in practice
Avg. Inflation Rate	j	0.026		US avg. for past 10 years‡
Avg. Mortgage Rate	j_m	0.05		See following reference ‡‡‡‡
Discount Rate	j_d	0.15		Per Ballard (suggested >=15%)‡‡
Energy Inflation Rate	j_e	0.056		US avg of last 3 years‡‡‡
Income Tax	i_i	0		No net income
Property Tax	i_p	0.014		US avg from 2007†
Assessed Value	i_{av}	0		
Salvage Tax	i_s	0		
EOL Salvage Value	k_{eol}	0.02		Assume 2% of end-of-life value
Tool Lifetime	T_t	15	Years	Typical value in practice
Energy Tax Credits	ITC	0	Dollars	
Energy Cost	c_e	0.1	$/kWhe	Typical U.S. value
Floor space Cost	c_{fs}	1291	$/$m^2$	US average for factory††
Building Depreciation	j_{br}	0.031		BEA rates† ††
Building Recovery	T_{br}	31	Years	BEA rates† ††
Building Footprint	a_{br}	Varies	m^2	
Line Speed	v_l	Varies	m/min	Approximation from DTI2010 (James et al., 2010)
Web Width	W	Varies	M	Lower widths at low volume
Hourly Labor Cost	c_{labor}	28.08	$/hr	Hourly wage per worker

‡ http://www.tradingeconomics.com/united-states/inflation-cpi
‡‡ Communications with Ballard Power Systems, Burnaby, B.C., Canada
‡‡‡ http://www.forecast-chart.com/inflation-usa-energy.html
‡‡‡‡ http://www.steelheadcapital.com/rates/
† http://www.nytimes.com/2007/04/10/business/11leonhardt-avgproptaxrates.html?_r=0
†† Selinger, B., (2011), “Building Costs,” DCEO, Illinois.
††† http://www.bea.gov/scb/account_articles/national/wlth2594/tableC.htm

Table 3.4. Manufacturing cost shared parameters.

Manufacturing cost shared parameters are summarized in Table 3.4. References are shown in the table and are a mixture of general industry numbers (e.g. annual operating days, inflation rate, tool lifetime) together with fuel cell specific industry assumptions (discount rate, web width, hourly wage).

An annualized cost of tool approach is adopted from Haberl (1994). The annualized cost equation and components are as follows:

$$C_y = C_c + C_r + C_{oc} + C_p + C_{br} + C_i + C_m - C_s - C_{int} - C_{dep}$$

where

C_y is the total annualized cost
C_c is the capital/system cost (with interest)
C_r is the replacements or disposal cost
C_{oc} is the operating costs (e.g. electricity) excluding labor
C_p is the property tax cost
C_{br} is the building or floor space cost
C_i is the tool insurance cost
C_m is the maintenance cost
C_s is the end-of-life salvage value
C_{int} is the deduction from income tax
C_{dep} is the deduction due to tool depreciation

Furthermore, all values are scaled to 2013 dollars. In the current version of the model C_r, the replacements or disposal cost and C_i, the tool insurance cost, are assumed to be zero. We assume no net income for fuel cell manufacturers, as is currently the case for LT PEM manufacturers and thus income tax credits such as interest tax credits do not factor into the calculations. The machine rate quoted above can be easily found from these annualized cost components (capital cost component, operating cost, and building cost). Appendix A contains detailed economic analysis and some of the mathematical formulas used in developing DFMA costing models.

Factory model

Two approaches were pursued: a global factory model with total area dependent on overall volume and including factors for non-production factory space, and secondly by incrementally adding factory area to each specific process module. It was found difficult to keep all modules coordinated in the first case, so later in the work, the factory costing shifted to the second, simpler approach. Factory cost contributions in both cases are found to be very small factors in general, especially as production volumes exceed 1000 systems per year.

Yield Considerations

As in other costing studies (James 2012) and as will be detailed in the DFMA analysis below, this work assumes that high yield is achieved at high manufacturing volumes. This stems from several implicit assumptions:

- Learning by doing over the cumulative volume of fuel cell component production and greater process optimization will drive yield improvement both within a given vendor, and from vendor to vendor through industry interactions (conferences, IP, cross vendor personnel transfers, etc.)
- Inline inspection improvement with greater inspection sensitivity and more accurate response to defects and inline signals.

- Greater development and utilization of "transfer functions" (Manhattan Projection 2011), e.g., development of models that relate inline metrics and measurements to output responses and performance, and resultant improvement in inline response sensitivity and process control.
- Utilization of greater feedback systems in manufacturing processing such as feed-forward sampling, for real time adjustment of process parameters (for example, slot die coating thickness and process parameter control).
- Systematic, integrated analysis to anticipate and prepare for yield excursions e.g., FMEA (failure modes and effect analysis).

Consideration of yield limiting mechanisms or FMEA-type analysis as a function of process tooling assumptions are out of scope here and would be very challenging in this type of analysis project without access to manufacturing data.

Initial Tool Sizing

The choice of initial tool sizing was governed by several factors. In some cases it was made on the basis of tool availability and in other cases it was dependent on the choice of batch sizes with smaller batch sizes leading to smaller tools. In general however, tooling decisions were made to support medium to high volume manufacturing of greater than 10 kWe and 1,000 systems per year. This choice was made on the basis of assuming that vertically integrated manufacturing would not be done for small volumes e.g., 100 kWe of total production a year. A cost optimized process for low volume manufacturing would have a very different mix of automated versus manual production lines as well as in-house manufactured versus purchased components. Nor was a detailed optimization study of low volume manufacturing a key priority for this work. Production volumes might also be expected to grow if sales of fuel-cell vehicles drive increased demand for fuel cell stack components.

Time-frame for Cost Analysis

The cost analysis utilizes largely existing manufacturing equipment technologies and existing materials with key exceptions to be noted (e.g., injection molding composite material for bipolar plates). It does not assume new high-speed manufacturing processes nor major fuel-cell technology advances such as much lower cost catalysts or membranes. The analysis is thus a "potential cost reduction" study for future costs with existing tools and mostly existing materials, and DOE cost targets for 2020 are used as a benchmark comparison for the cost estimates here. The study assumes that higher overall volumes will drive significant improvements in yield, but it is not a market adoption or market penetration study and therefore timelines will vary according to the assumptions made for market adoption. Stationary fuel cell systems may also benefit from growth in the transportation sector and higher volumes achieved for fuel cell components in that sector over the next few years may reduce the cost of components for stationary applications (e.g., GDL, membranes, metal plates, etc.).

4 DFMA Manufacturing Cost Analysis

This chapter discusses the methodology and results of the design for manufacturing and assembly (DFMA) direct manufacturing cost analysis for all stack modules, namely catalyst coated membrane, gas diffusion layer, plates, MEA frame/seal, and the stack assembly process. The following DFMA stack module cost analysis is for the CHP system application with reformate fuel input. A very similar manufacturing process flow also applies to the CHP H_2 and backup power systems. Final stack module cost results were computed in a similar manner for CHP H_2 and BUP systems but are not presented here. CHP system with H_2 fuel have roughly 10% decrease in the number of cells due to higher performance, and the backup power systems stack configuration were sized according the BU power functional specifications described in Chapter 2.

4.1 Catalyst coated membrane

4.1.1 Process Flow

The catalyst coated membrane (CCM) is historically the most costly portion of the fuel cell stack because of the precious metal loading which, even with much reduced loadings compared to ten to fifteen years ago, is still expected to be a leading cost component for the stack. We find this to be the case here, and thus this module and its cost sensitivities are a key focus area of this report.

For this work we adopt a dual decal transfer coating process as a base flow with dual coating lines for cathode and anode catalyst followed by a lamination step to combine the two layers to form a CCM, all using automated roll-to-roll or web line processing. The flow is similar in concept and materials to U.S. Patent 20090169950.

Slot die coating was chosen as a representative process for catalyst ink deposition since it is a mature technology with a high degree of process control capability in high volume manufacturing demonstrated for other thin film products and is expected to be able to scale up to larger volumes for the catalyst coating operation. Other deposition techniques could be used but were not explored (spray coating, gravure, roll coating, etc.). Ultra-low catalyst loading e.g. nanostructured thin films are not required for longer lifetime stationary applications where a higher loading can be amortized over a longer life. On the down side, wet deposition manufacturing issues include the management of volatile and/or explosive solvents for safety and environmental control, wet mixing control of viscosity, particle uniformity, and management of plumbing lines and concentration gradients.

The representative process is shown in the schematic figures below and vendor drawings (in Appendix C). For the slot die coating, catalyst-containing ink is mixed in an ink tank and extruded through the slot die coater with an ink pump. Following deposition, the coated membrane or backing layer passes through an IR drying oven to bake off the ink solvents. Anode-side and cathode-side catalyst deposition is done on separate lines due to swelling issues during drying and product quality and process control difficulties associated with concurrent or serial deposition. Anode and cathode layers are pressed together in a heated nip roller to form the final CCM product. We also model a serial or concurrent deposition for the CCM cost, described in Appendix C.

For thickness measurement, it is common to have an incoming membrane thickness and post deposition thickness measurement, commonly done with beta gauges. The overall deposition area is enclosed in a clean room environment at Class 1000 to control for contaminants and particles. An inspection is done after each deposition and thermal treatment pass. Fume hoods to thermal oxidizers are employed to control VOC, CO, and volatile hazardous air pollutant (HAP) emissions.

Overall, both tooling lines and equipment configuration have been validated by both industry advisors and vendor inputs.

4.1.2 Functional Specifications for CCM

The required area of CCM (same area for GDL for consistency) is derived from the functional specifications (259cm^2 of active area), with the following dimensions 32.375cm (L) x 8cm (W). We also assumed 0.5 cm extra length and width from the active area for bonding to the MEA with the following dimensions 33.375cm (L) x 9cm (W) = 291.375cm^2 total area. One sheet of CCM is assumed per MEA cell.

CCM Design

The CCM membrane is Nafion® membrane from DuPont with 25.4μm thickness and is assumed to be a purchased part. The decision to purchase membrane was based on industry input, the cost and complexity to bring up a membrane manufacturing line, and the fact that Nafion® is readily available and would be expected to scale in price with increasing industry activity. Cathode and anode Pt loading is assumed to be 0.4 mg/cm^2 and 0.1 mg/cm^2, respectively. Additionally, 0.5mg/cm^2 of ruthenium is also assumed for anode layer which improves its tolerance to CO. This loading is similar to that assumed for the Manhattan Project (2011) and Pt loading and price is also a key variable for the sensitivity analysis below.

In fact, platinum is one of the key cost factors in the overall cost not only for CCM, but also for the fuel cell stack and it usually makes up 40-60% of the total CCM cost (Sousa, 2011, Manhattan Project, 2011). Selection of Pt price has varied between several studies, for example the study done by DTI in 2010 for automotive fuel cells assumed a Pt price of $1,100 per troy ounce. The spot market price of Pt (see Fig. 4.1) is subject to large fluctuations, and thus the estimated Pt price should be made carefully. In 2008 for example, the price of platinum varied greatly (as shown in Figure 4.1), with a peak daily trading values reaching of $2,280/tr.oz. Average price over last five years was $1500 per tr.oz.

In this study we have adopted actual cost estimates for fine grade platinum powder for fuel cell applications, which are available from different suppliers. In this study, the baseline Pt price used in CCM calculations was quoted from Richest Group in Shanghai China for fine Pt powder (particle size 5-100nm; purity >99%) with an average price of $1,800 per tr.oz. The required area of CCM is derived from the functional specifications above and is assumed to be 291.375cm^2 per cell.

CCM is made from (1) depositing a catalyst layer (cathode) over a Nafion® membrane; (2) depositing an anode layer over polyester paper then (3) attaching these two layers by a lamination process.

Nafion®, a registered trademark name by DuPont, is a widely used membrane in PEM fuel cells. Nafion® was originally developed by DuPont as a chloro-alkali membrane with perfluorinated sulfonic acid (PFSA) the main chemical group. Other companies have developed other PFSA-based membranes, including membranes from Dow, Asahi, and Gore (James et al., 2010). Besides the Pt catalyst, the PEM membrane has been known as one of the most costly components in PEM fuel cells.

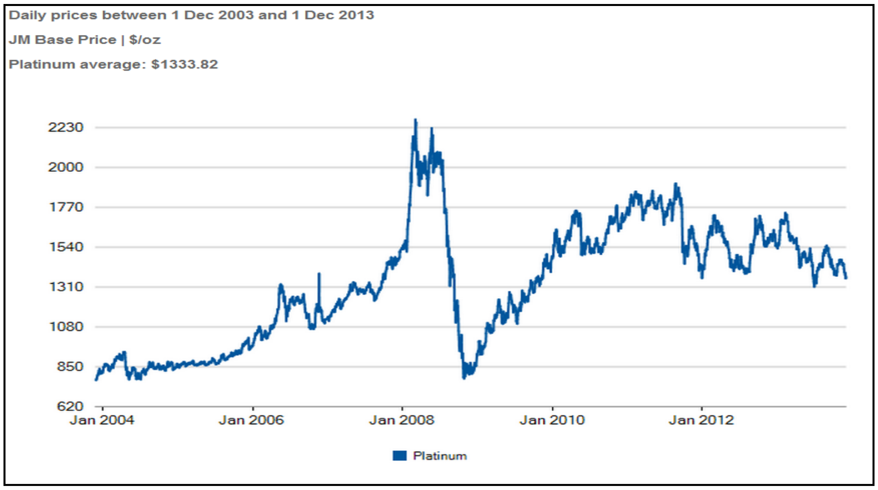


Figure 4. 1. Platinum price in the spot market for the last ten years (2003-2013) (Source: http://platinum.matthey.com/prices/price-charts/).

Nafion®, a registered trademark name by DuPont, is a widely used membrane in PEM fuel cells. Nafion® was originally developed by DuPont as a chloro-alkali membrane with perfluorinated sulfonic acid (PFSA) the main chemical group. Other companies have developed other PFSA-based membranes, including membranes from Dow, Asahi, and Gore (James et al., 2010). Besides the Pt catalyst, the PEM membrane has been known as one of the most costly components in PEM fuel cells.

In this study, Nafion® membrane was modeled as a commodity part rather than being manufactured in-house. Total membrane cost used in this study is shown in Figure 4.2 below. This curve shows the price of 25μm thickness, homogeneous PFSA membranes (Nafion® membrane) as quoted by DuPont; however, a declination in price with volume is expected due to economy of scale. All estimates represent membrane material cost alone and do not include any catalyst or catalyst application cost. The catalyst layer is made up from a mixture of several materials forming the catalyst ink and deposited over membrane using various coating technologies such as decal transfer method, dual coating method and/or vapor deposition methods. An example of ink components and weight fractions are shown in Table 4.1.

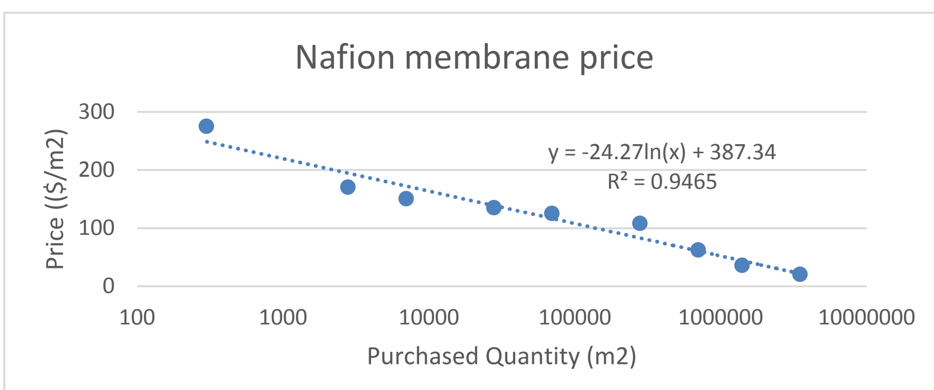


Figure 4. 2. Nafion® membrane price.

BOM- Cathode ink U.S. Patent 20090169950			
Constituent	**Wt. (g)**	**Wt. Fraction**	**Supplier**
Pt	58.29	0.062	Richest Group, Shanghai, China
Carbon black	28.71	0.031	Sigma-Aldrich
Nafion® Ionomer	24.92	0.027	DuPont
Total solids	111.92	0.120	
Solvents	820.75	0.880	Sigma-Aldrich
Total wt.	932.67	1.000	

Table 4.1. Cathode ink constituents based on U.S. Patent 20090169950.

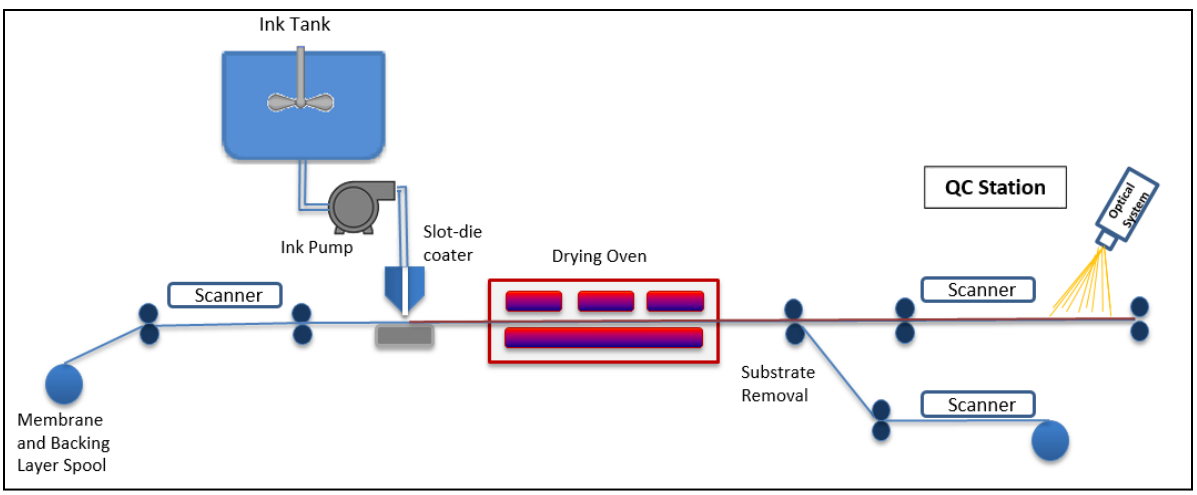
Polyester PFA paper is used as a substrate for the deposited anode in the decal transfer method. Table 4.2 shows the specifications for this polyester paper.

Material	Specifications	Price ($/m^2)	Supplier
Polyester film	25.4μm 12inch x 50ft rolls	0.70	United States Plastic Corp.

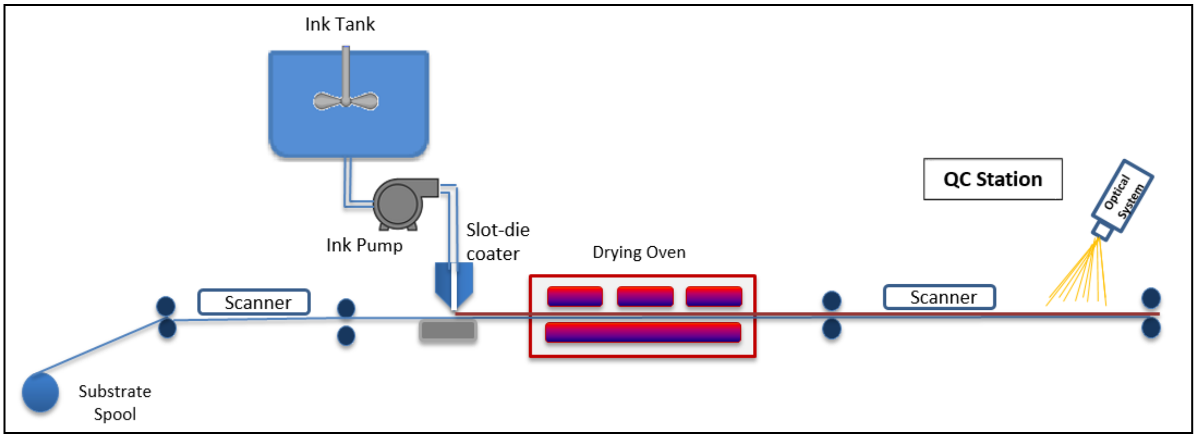
Table 4.2. Specification and price of the polyester film

4.1.3 CCM Manufacturing

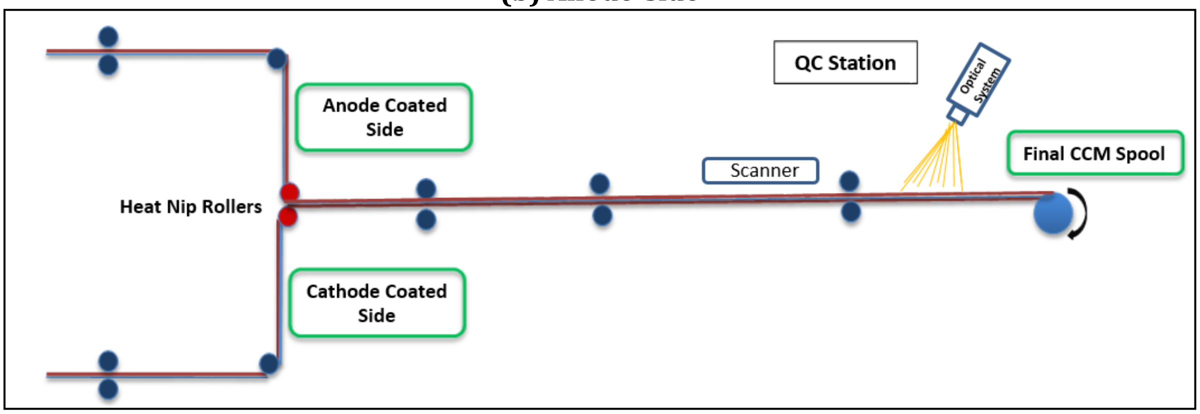
A representative flow is shown below. The schematic diagrams below show the general process flow, while a set of side view diagrams depicting one detailed equipment configuration from web line vendor Conquip Inc. is included in Appendix C.



(a) Cathode-side



(b) Anode-side



(c) Final CCM

Figure 4.3. Schematic diagram for roll-to-roll coating line: (a) Cathode line; (b) Anode line; and (c) Final product.

4.1.4 Process Parameters and Equipment Costs

Yield assumptions (per square-meter of CCM) are shown in Figure 4.4 below. Yield is assumed to improve with output volume as discussed above. Note that "scrap" material is not discarded but the catalyst is recovered by shipping rejected material to a Pt recovery firm with the assumption that 90% of Pt material is recovered and the remaining 10% Pt is assumed to cover the cost of recovery.

Web width was chosen to be in multiples of 9cm (width of CCM) for minimal waste from Nafion® rolls. Minimum web width was set to 45m for CCM areas (to minimize waste material and maximize the line utilization).

The cost of defect inspection and metrology equipment (in-situ vision and thickness gauges) is included in the equipment costs below. Set-up time and cost are included in the analysis (1 hour setup per working day is assumed). The machine footprint is a function of the web width and machine size.

Equipment costing is listed by type of equipment below based on equipment quotes from Conquip, Inc. Slot-die equipment quotes are consistent with quotes from other vendors such as Eurotech/Coatema Coating Machinery GmbH. Overall, 38% of equipment cost for the CCM is for the slot die coating unit and about 20% for quality control inspection components. Table 4.3 summarizes costs by production module. Appendix C includes cost breakdown for each process line (i.e., cathode line, anode line and final CCM product).

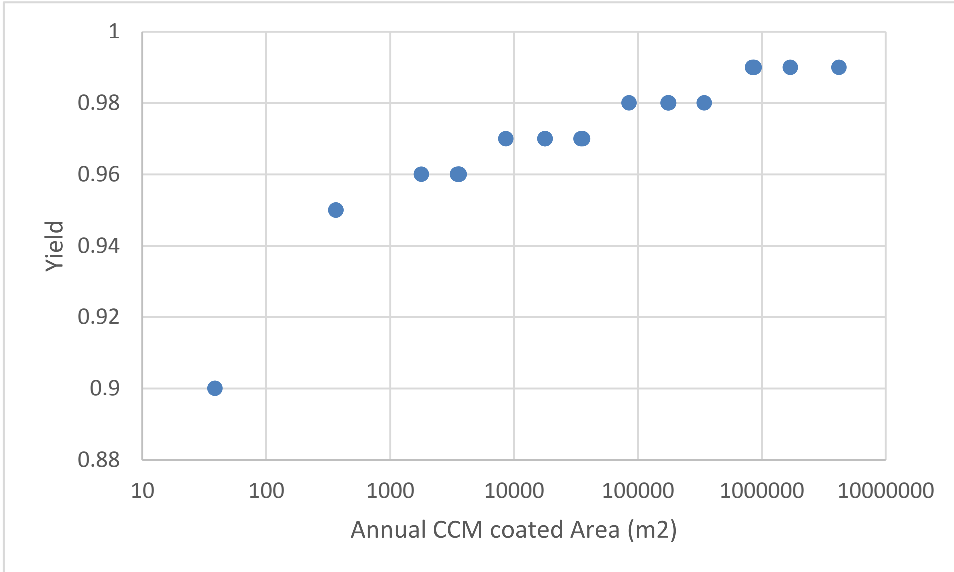


Figure 4.4. Yield assumption for CCM.

4.1.5 Stack parameters and assumptions

In this section, the 100kWe is taken to be a base case system and calculations for other system sizes can be found in Appendix C. Stack parameters and assumptions for a 100kWe system with reformate fuel are shown in Table 4.4 below. Line utilization is seen to be low until the 10000 systems per year manufacturing level. Note that line utilization applies to all process modules, since the process flow is a continuous process.

Module	**Total Cost for Decal Transfer Coating Process (X1,000)**
Slot Die coater	$1,521
IR Oven	$360
Mixing and Pumping System	204
Quality Control System	$850
Wind/Unwind System	$645
Installation	$390
Total	**$3,970**

Table 4.3. Overall Process Equipment Cost by Module.

System Size (kW)	100			
Systems/Year	100	1,000	10,000	50,000
Required Lines	1	1	1	2
Scrap	4%	3%	2%	1%
Overall Yield	96%	97%	98%	99%
Line Utilization	0.81%	8.02%	79.38%	90.56%
No. of active cells per system	1587	1587	1587	1587
CCM Total Annual Actual Area (m^2)	4,114	41,140	411,400	2,057,000
CCM Total Annual Used Area (m^2)	4,285	42,410	419,700	2,078,000
Web Width (m)	0.45	0.45	0.45	0.90
Total Pt loading (g/m^2) (anode=$1g/m^2$; cathode=$4g/m^2$)	5	5	5	5
Avg. Availability	0.85	0.85	0.85	0.92
Max Annual Area (m^2)	528,800	528,800	528,800	2,294,000
Annual Operation Hours (No setup time)	26.45	261.8	2,591	3,206
Annual Operation Hours (+setup time)	28.45	280.8	2,777	3,436
Required labor	2	2	2	4
Worker Rate ($/hr)	29.81	29.81	29.81	29.81

Table 4.4. Stack parameters and assumptions for a 100kW system.

4.1.6 CCM Cost Summary (Roll-to-Roll Coating Process)

Machine Rates by Module

Machine rates for the slot-die coater are shown below for the 100kW base system; however, detailed machine rate calculations for other modules can be found in appendices.

Slot-Die Coater and IR oven:

Some important assumptions for slot-die coater are:

- Dwell time and maintenance factor per James et al., (2010)
- Power consumption (5kW for slot-die coater and 50kW for IR oven) based on machine specifications from EuroTech.
- Machine footprint based on web width and line length and assumed class 1000 clean room for slot die-coater and IR oven.
- Initial system costs assumes installation costs are 10% of equipment capital cost (based on EuroTech and Conquip estimates)
- Salvage value is the amortized end-of-life value of the tool.
- Property tax is proportional to the machine capital.

System Size (kW)	100			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Line speed (m/min)	6	6	6	6
Required lines	1	1	1	2
Web width (m)	0.45	0.45	0.45	0.9
Line Utilization	0.81%	8.02%	79.38%	90.56%
Maintenance Factor	0.1	0.1	0.1	0.1
Auxiliary Costs Factor	0	0	0	0
Power Consumption (kW)	5	5	5	5
Machine Footprint (m^2)	33.6	33.6	33.6	67.2
Initial Capital ($)	514,000	514,000	514,000	3,042,000
Initial System Cost ($)	545,400	545,400	545,000	3,346,000
Depreciation ($/yr)	3.36E+04	3.36E+04	3.36E+04	1.99E+05
Amortized Capital ($/yr)	8.34E+04	8.34E+04	8.34E+04	4.94E+05
Auxiliary Costs ($/yr)	0	0	0	0
Maintenance Costs ($/yr)	7581.06	7581.06	7581.06	44868.66
Salvage Value ($/yr)	928.30	928.30	928.30	5494.17
Energy Costs ($/yr)	34.02	335.77	3320.96	8218.19
Property Tax ($/yr)	2837.17	2837.17	2837.17	16791.84
Building Costs ($/yr)	11523.50	11523.50	11523.50	81342.32
Interest Tax Deduction ($/yr)	0	0	0	0
Depreciation Deduction ($/yr)	0	0	0	0
Machine Rate ($/hr)	**3670.97**	**373.04**	**38.79**	**186.05**
- Capital ($/hr)	2898.54	293.70	29.69	142.04
- Operational ($/hr)	267.67	28.20	3.93	15.45
- Building ($/hr)	504.77	51.15	5.17	28.56

Table 4.5. Machine rates for slot-die coater.

System Size (kW)	100			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Maintenance Factor	0.1	0.1	0.1	0.1
Auxiliary Costs Factor	0	0	0	0
Power Consumption (kW)	50	50	50	50
Machine Footprint (m^2)	16.8	16.8	16.8	33.6
Initial Capital ($)	1.08E+05	1.08E+05	1.08E+05	7.20E+05
Initial System Cost ($)	1.19E+05	1.19E+05	1.19E+05	7.92E+05
Depreciation ($/yr)	7.04E+03	7.04E+03	7.04E+03	4.70E+04

Amortized Capital ($/yr)	1.75E+04	1.75E+04	1.75E+04	1.17E+05
Auxiliary Costs ($/yr)	0	0	0	0
Maintenance Costs ($/yr)	1589.58	1589.58	1589.58	10619.80
Salvage Value ($/yr)	194.64	194.64	194.64	1300.40
Energy Costs ($/yr)	340.23	3357.69	33209.64	82181.86
Property Tax ($/yr)	594.89	594.89	594.89	3974.40
Building Costs ($/yr)	20335.58	20335.58	20335.58	40671.16
Interest Tax Deduction ($/yr)	0	0	0	0
Depreciation Deduction ($/yr)	0	0	0	0
Machine Rate ($/hr)	**1411.28**	**153.75**	**26.29**	**73.62**
- Capital ($/hr)	607.76	61.58	6.23	33.62
- Operational ($/hr)	67.83	17.62	12.53	27.01
- Building ($/hr)	735.69	74.55	7.54	12.99

Table 4.6. Machine rates for IR oven.

CCM costing results ($/m^2 and also $/kW) are given below for 10kW and 100kW system sizes. Cost is split into several components to emphasize the effect of each cost component on the overall cost of CCM. These cost components include: capital cost, operational cost, building cost, labor cost, material cost, and scrap cost. Direct material costs include the cost of Nafion® 211 (varies with volume), anode substrate (polyester), carbon black, and solvents. Polyester film, carbon black and solvents are assumed to have a flat price as a function of volume because they are assumed to be commodity items.

Process costs include direct and indirect manufacturing costs and are divided into three components: (1) capital costs (e.g. tools); (2) operational costs (e.g. energy, maintenance); and (3) building costs (e.g. floor space and cleanroom usage)

Material scrap or material which is rejected and not sent on in the process line, represents losses from all the process modules above lumped together. The quantity of material rejected varies inversely with yield, but based on industry inputs, the Pt can be recovered with 90% of the Pt value recovered. No recovery is assumed for the Nafion® membrane since the recovery process may damage the membrane structure. Thus a negative material cost means that net positive value is recorded from material scrap that is sold for precious metal recovery. Note that scrap cost also includes labor, other materials, process cost and factory costs. Even with a 90% recovery percentage of Pt, scrapped CCM is very costly since other materials will be scrapped (e.g. membrane, solvents, and other materials). Moreover, all associated processing and capital cost investments will be lost as every step in making CCM shares a part of capital and operational costs. Tables 4.7 and 4.8 summarize final CCM cost expressed in $/m^2 for 10kW and 100kW systems, respectively. Costs in units of $/kW are tabulated in Appendix C for all system sizes.

System size (kW)	10			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/m^2)	606.16	522.36	450.27	402.56
Labor ($/m^2)	0.50	0.39	0.40	0.39
Process: Capital ($/m^2)	401.25	40.55	4.10	0.83
Process: Operational ($/m^2)	37.07	3.87	0.52	0.22
Process: Building ($/m^2)	174.92	17.68	1.79	0.36
Material Scrap ($/m^2)	36.77	2.65	-1.99	-2.39
Total ($/m²)	**1,256.66**	**587.50**	**455.08**	**401.98**

Table 4.7. Cost analysis for 10kW CHP reformate fuel system.

System size (kW)	100			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/m^2)	523.43	451.30	385.40	340.51
Labor ($/m^2)	0.40	0.39	0.39	0.20
Process: Capital ($/m^2)	42.16	4.26	0.43	0.55
Process: Operational ($/m^2)	4.02	0.54	0.18	0.12
Process: Building ($/m^2)	18.38	1.86	0.19	0.12
Material Scrap ($/m^2)	2.80	-1.95	-2.75	-1.82
Total ($/m²)	**591.17**	**456.40**	**383.85**	**339.68**

Table 4.8. Cost analysis for 100kW CHP reformate fuel system.

4.1.7 CCM Cost Summary

CCM cost is seen to fall from about $1,200/m^2 at low volume to about $300/m^2 at high volume (Figure 4.5). Figure 4.6 shows cost breakdown where it can be seen that at lower volumes of 1MW (100 systems per year, 10kW systems), capital costs constitute over 30% of CCM costs, while at high volume, material costs dominate. Similarly, platinum is the dominant material cost followed by Nafion® membrane. For example, platinum accounts for 51% of total CCM material cost of the 10kW fuel cell at an annual production volume of 100 units, and this fraction jumps to around 85% of total CCM material cost for 100kW fuel cell system at an annual production volume of 50,000 units.

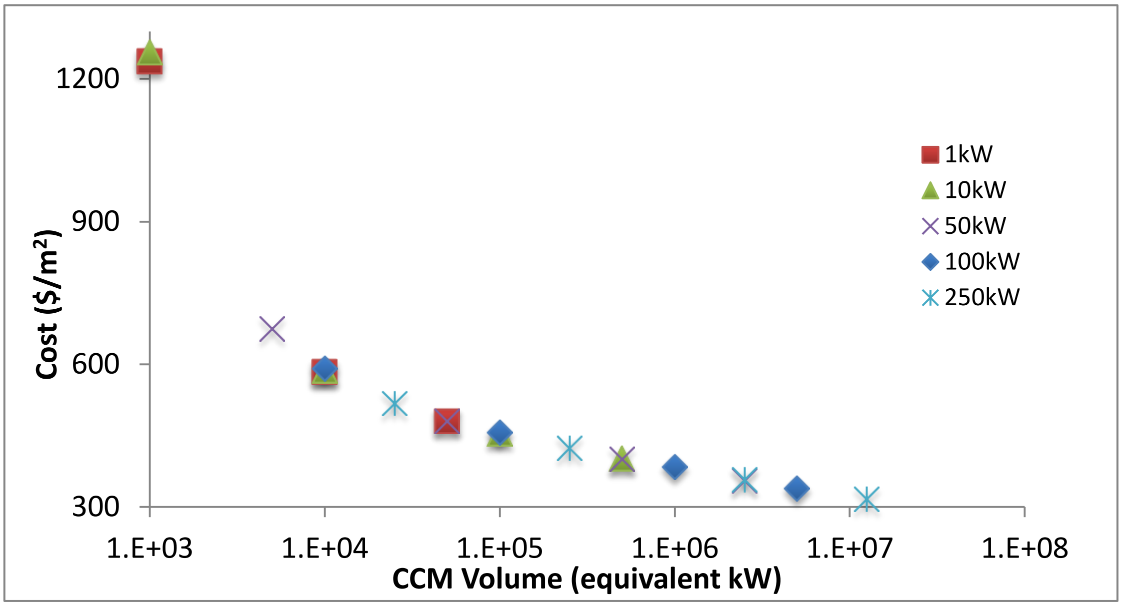
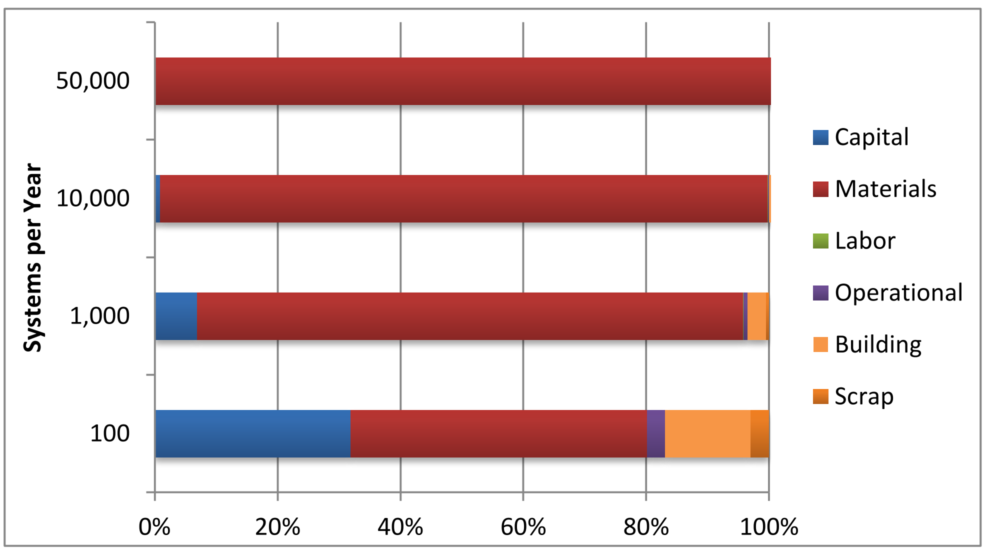
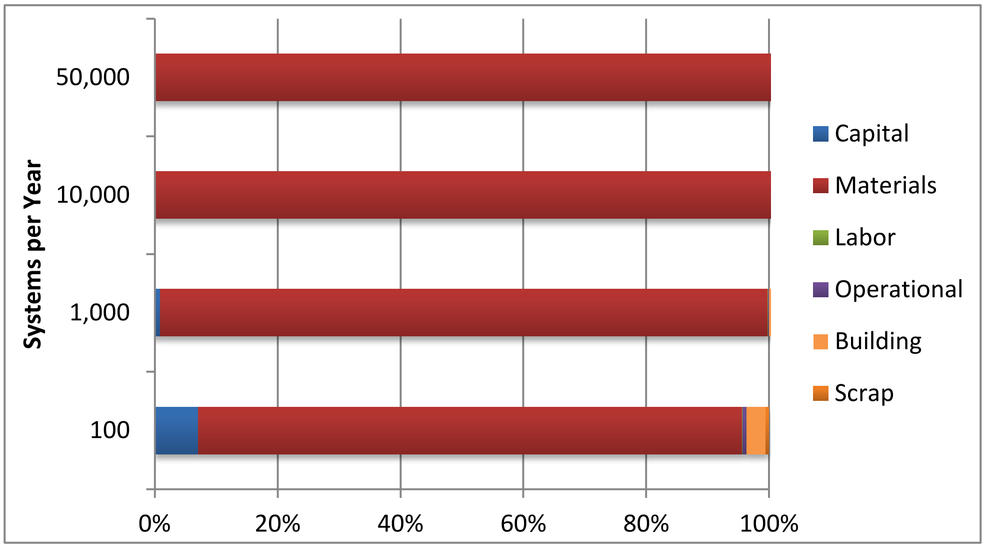


Figure 4.5. CCM cost vs. production volume in ($/m² of CCM).



a) Cost breakdown of CCM (10kW system)



b) Cost breakdown of CCM (100kW system)

Figure 4.6. Fraction of CCM costs as a function of annual production volume for: (a) 10kW system; and (b) 100kW system.

4.2 Gas Diffusion Layer (GDL)

The required area of the GDL is derived from the functional specifications discussed in Chapter 3 and included in the appendix. The active area of the cell is 259cm^2 or 32.375cm (L) x 8cm (W). This leads to a total area of 291.375 cm^2 with 0.5 cm extra length and width allotted to the active area for bonding to the MEA. Two sheets of GDL are in each cell.

4.2.1 GDL Design

Key GDL design parameters are shown in Table 4.9 with material loadings and layer thicknesses adopted from earlier DOE cost studies (Sinha and Yang, 2010; James et al., 2010). The macro-porous layer is taken to be a purchased carbon fiber paper per the criteria described above with multiple suppliers (e.g. Toray, AvCarb) and multiple customers (various fuel cell MEA companies). Carbon fiber paper is less expensive than a starting substrate of carbon fabric, while still meeting the performance requirements of the fuel cell stack.

Component	Description
Macro-porous layer	Purchased (carbon fiber paper)
Macro-porous PTFE loading	4 g/m^2 (Sinha and Yang, 2010)
MPL PTFE loading	15 g/m^2 (Sinha and Yang, 2010)
MPL Carbon Black loading	16 g/m2 (Sinha and Yang, 2010)
Carbon Fiber Paper material scrap (cutting)	90% (fixed)
Macroporous layer thickness	280um (James et al., 2010)
Microporous layer thickness	40um (Sinha and Yang, 2010, James et al., 2010)

Table 4.9. Key GDL design parameters.

4.2.2 GDL Manufacturing

The GDL process flow is adopted from reference (James et al., 2010) but follows a fairly standard process flow described in GDL patents (e.g., "Preparation of Gas Diffusion Layer for Fuel Cell," U.S. Patent 20090011308 A1, 2009).

We adopt the process flow from (James at al., 2010) as shown in Fig. 4.8. A macroporous layer or carbon paper in this case is first immersed in a PTFE solution bath followed by a drying step in an IR oven. The microporous layer is formed by a spray deposition of the microporous solution followed by an IR drying step and a higher temperature-curing step.

The bill of materials (Table 4.10) includes a purchased macroporous layer, filler (PTFE), PTFE, and carbon black for the microporous layer formation. Material costs are also adopted from the literature.

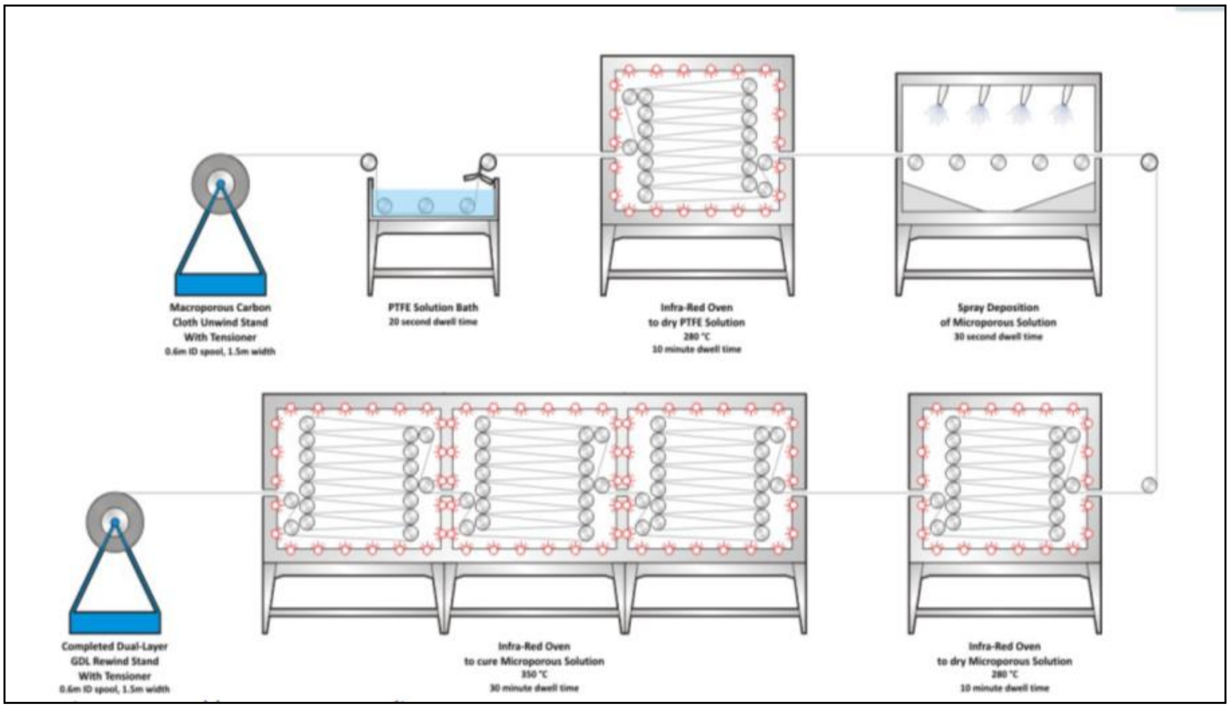


Figure 4.8. Schematic of the GDL manufacturing process (James et al., 2010).

Component		Material	Cost ($/kg)	Cost ($/L)	Comments
Macroporous Layer	Substrate	Carbon Fiber	See Plot	-	In 2010 USD (James et al., 2010)
	Filler	PTFE	22.17	-	In 2013 USD (Sinha and Yang, 2010)
MPL	Matrix	PTFE	22.17	-	In 2013 USD (Sinha and Yang, 2010)
	Filler	Carbon Black	3.581	-	In 2013 USD (Sinha and Yang, 2010)

Table 4.10. Bill-of-Materials for GDL.

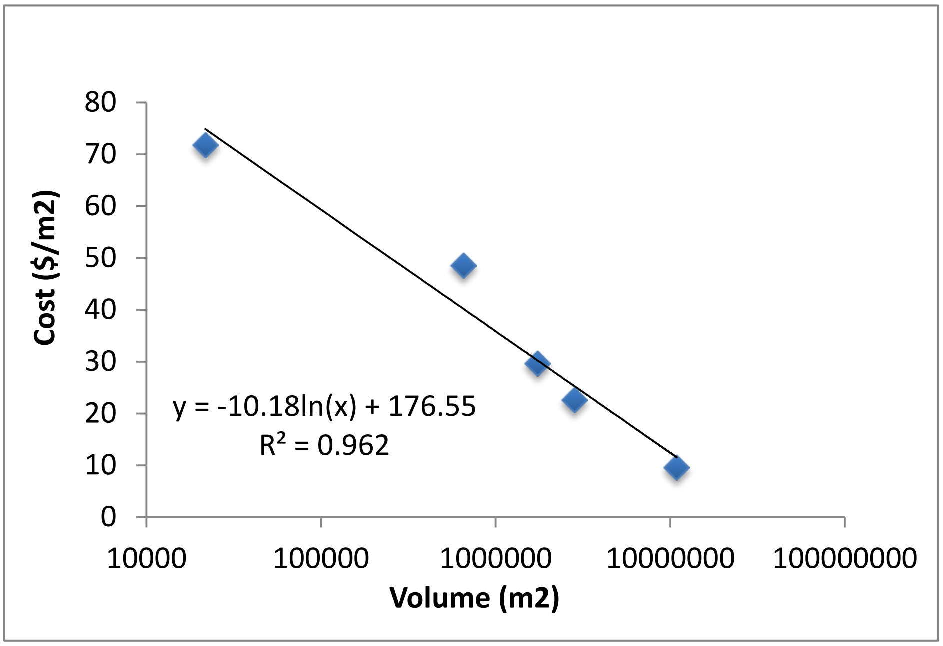


Figure 4.9. Interpolated values for macroporous layer from values given by the DTI2010 (James et al., 2010) in 2010 dollars; 280um thickness.

4.2.3 Web Line Process Assumptions:

The machine footprint is a function of the web speed, web width, and processing time. Web width varies between 0.5m, 1m, and 1.5m depending on production volume. Yield assumptions (per square-meter of GDL), set-up time and line availability are assumed to trend with volume as shown in Figure 4.10. In particular, the low-end yield is at 90% increasing to 99.5% yield at the highest volume.

Setup time starts at 30 minutes and exponentially decays after 1,000m^2 of annual volume (Fig. 4.10). The logic to determine the number of lines, line utilization, line width, and inspection type in the manufacturing flow is described in Appendix C. Table 4.11 summarizes other parameters of the production line such as machine footprint, inspection method, required labor, production time to make corresponding area and line yield. Manual inspection assumes one inspection station for every 2 lines (rounded down), $20,000 capital per inspection station and an inspection rate of 3m/min with operator visual inspection only. Automated inspection assumes every line has an inline inspection unit, $100,000 capital per line, and the inspection rate is the same as the line speed (since it is inline). A maximum of two lines per worker is assumed with an additional worker added if manual inspection is needed. The number of required workers is shown in Table 4.11. Note that the decrease in the number of workers is due to the inspection technology change (from manual to automatic), which reduces the requirement of an additional worker.

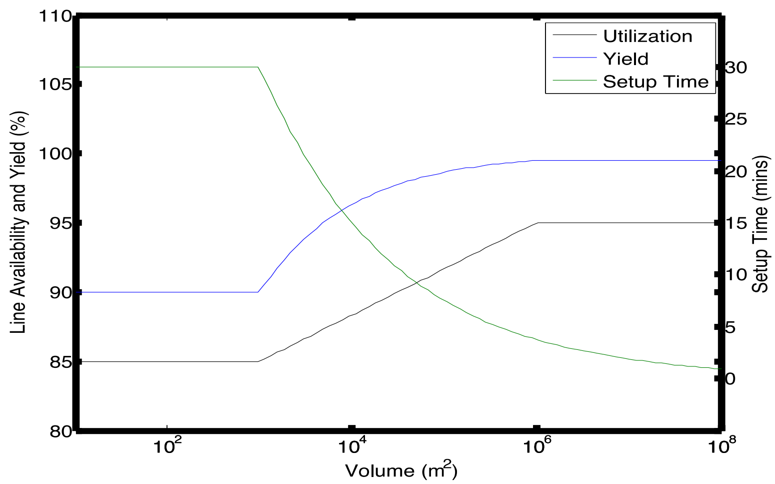


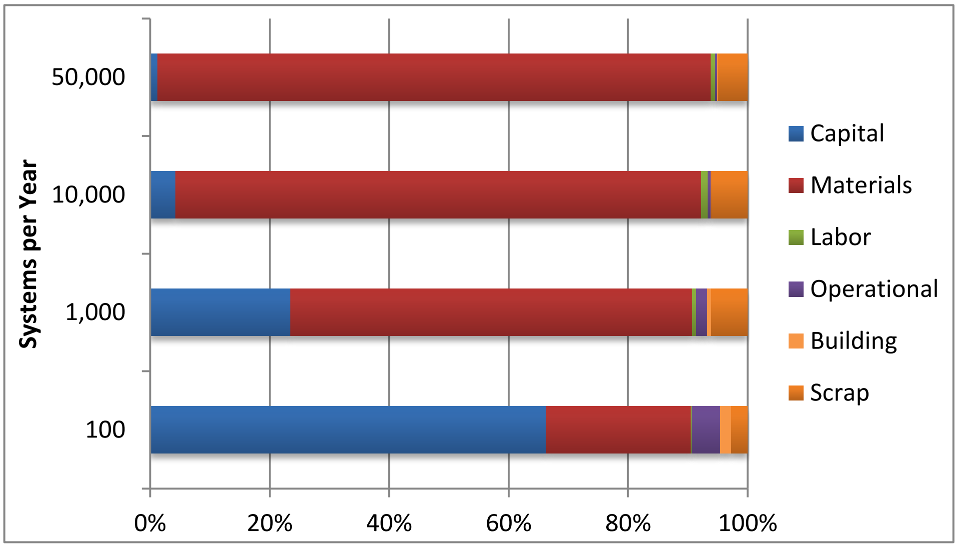
Figure 4.10 Utilization, yield and setup time for GDL manufacturing process.

Size (kW)	Volume	GDL Volume (m2)	Footprint (m2)	Inspection	No. Workers	Tool Runtime (hr)	Line Yield
1	100	88.13	30.1	Manual	2	1.36	90%
	1,000	881.3	30.1	Manual	2	13.6	90%
	10,000	8,813	30.1	Manual	2	125.4	91.72%
	50,000	44,060	30.1	Manual	2	590.1	93.02%
10	100	855.4	30.1	Manual	2	13.2	90%
	1,000	8,554	30.1	Manual	2	121.8	91.7%
	10,000	85,540	30.1	Manual	2	1,117	93.56%
	50,000	427,700	53.2	Auto	1	5,261	94.88%
50	100	4,235	30.1	Manual	2	61.92	91.14%
	1,000	42,350	30.1	Manual	2	568.1	92.99%
	10,000	423,500	53.2	Auto	1	5,212	94.87%
	50,000	2,118,000	212.8	Auto	4	24,530	96.21%
100	100	8,227	30.1	Manual	2	117.3	91.67%
	1,000	82,270	30.1	Manual	2	1,076	93.53%
	10,000	822,700	106.4	Auto	2	9,875	95.42%
	50,000	4,114,000	372.4	Auto	7	46,490	96.77%
250	100	20,530	30.1	Manual	2	282.9	92.40%
	1,000	205,300	53.2	Auto	1	2,595	94.28%
	10,000	2,053,000	212.8	Auto	4	23,810	96.19%
	50,000	10,260,000	851.2	Auto	16	113,100	97.55%

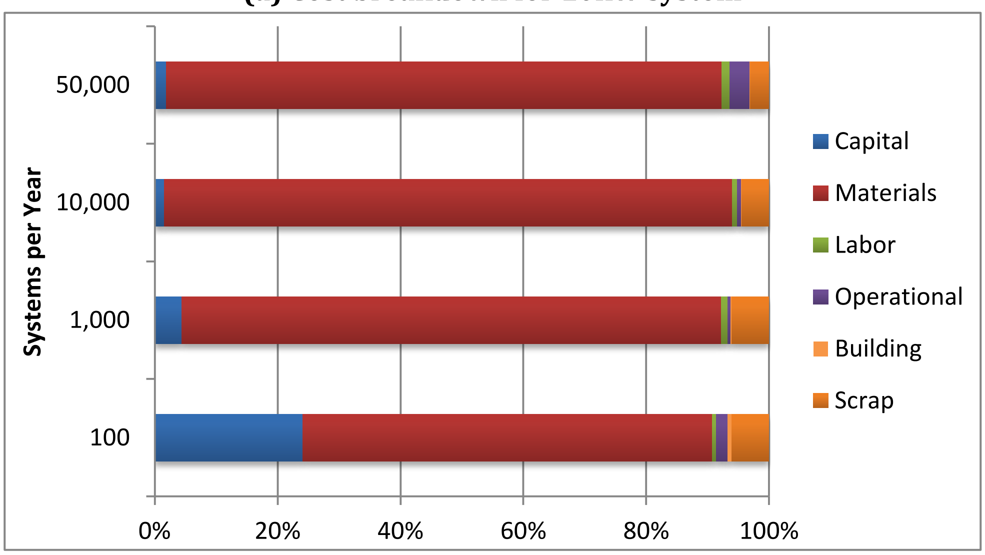
Table 4.11. Web line parameters as a function of system size and volume.

4.2.4 GDL Cost Summary

All values are in units of $/m^2 unless otherwise specified. Material costs include both direct materials and scrap. Labor is subdivided into value added labor, which is the labor during actual processing, and non-value added labor, which consists of setup time and inspection. Process cost is broken down into three components: (a) net capital equipment cost, (b) operational cost (e.g. maintenance and electricity), and (c) factory floor space (i.e. building). Tables 4.12 and 4.13 summarize GDL cost calculations for 10kW and 100kW systems, respectively.



(a) Cost breakdown for 10kW system



(b) Cost breakdown for 100kW system

Figure 4.11. Fraction of GDL costs as a function of annual production volume for: (a) 10kW system and (b) 100kW system.

System size (kW)	10			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/m^2)	120.28	94.23	68.19	49.98
Labor ($/m^2)	1.05	0.94	0.84	0.39
Process: Capital ($/m^2)	329.61	32.96	3.30	0.70
Process: Operational ($/m^2)	23.69	2.49	0.36	0.18
Process: Building ($/m^2)	9.17	0.92	0.09	0.03
Material Scrap ($/m^2)	13.36	8.53	4.69	2.70
Total ($/m^2)	**497.17**	**140.07**	**77.47**	**53.98**

Table 4.12. GDL cost analysis for 10kW CHP system with reformate fuel.

System size (kW)	100			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/m^2)	94.67	68.63	42.58	24.38
Labor ($/m^2)	0.94	0.84	0.38	0.35
Process: Capital ($/m^2)	34.27	3.43	0.73	0.51
Process: Operational ($/m^2)	2.58	0.37	0.31	0.89
Process: Building ($/m^2)	0.95	0.10	0.03	0.02
Material Scrap ($/m^2)	8.60	4.75	2.04	0.81
Total ($/m^2)	**142.03**	**78.11**	**46.08**	**26.96**

Table 4.13. GDL cost analysis for 100kW CHP system with reformate fuel.

4.3 MEA Frame/Seal

Two approaches for MEA frame sealing are shown in Table 4.14. The bordered or framed MEA approach has a frame that overlaps the edges and sandwiches the GDL/CCM/where "the sealing frames can be polyesters, polyethylenes, polypropylenes, polyimides, and thermosets. The sealing frame may be a rigid laminate material that imparts a desired rigidity to the resulting sealed MEA… sealing frames may also contain a pressure-activated adhesive, such as a silicone or acrylic-based adhesive, or may contain a thermally-activated adhesive that may be a thermoset, a thermoplastic, or combinations thereof" (S.J. Chiem, U.S. Patent 2009/0004543A1 (2009)).

By contrast, the edge sealed approach or flush cut MEA utilizes a sealant in direct contact with the GDL/CCM/GDL MEA. For example, the "edge seal may be cast in place, in one step, on a suitably sized, flush-cut MEA subassembly using liquid injection molding (LIM) techniques and a suitable polymerizable liquid sealant material" (R.H. Artibise, U.S. Patent 7070876 (2006)).

The framed MEA approach is expected to be more durable due to less edge stresses and is easier to align since the frame structure can be fairly rigid. However, the approach wastes catalyst compared to the edge sealed approach. For this work, we adopt the frame sealed architecture as our baseline flow since CHP systems can be continuous power applications and require lifetimes of greater than 20,000 hours. We also choose to be conservative even for the case of lower lifetime backup power applications, and leave the edge seal approach for backup power applications for future work.

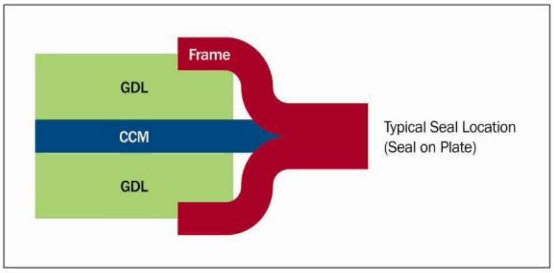
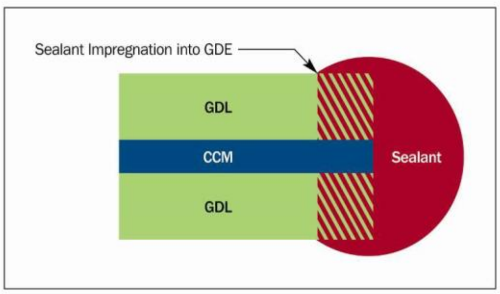
Approach	Pros	Cons
Bordered or Framed MEA 	More Durable, >20k hours; Easier to align and register since frame is sufficiently rigid	May waste catalyst
Edge Sealed or Flush Cut MEA 	Better catalyst utilization; favored for very small, high aspect ratio MEAs	Additional edge stress, less than 20k hours lifetime

Table 4.14. Two approaches to MEA frame sealing as described in Manhattan Project (2011).

4.3.1 Frame Design

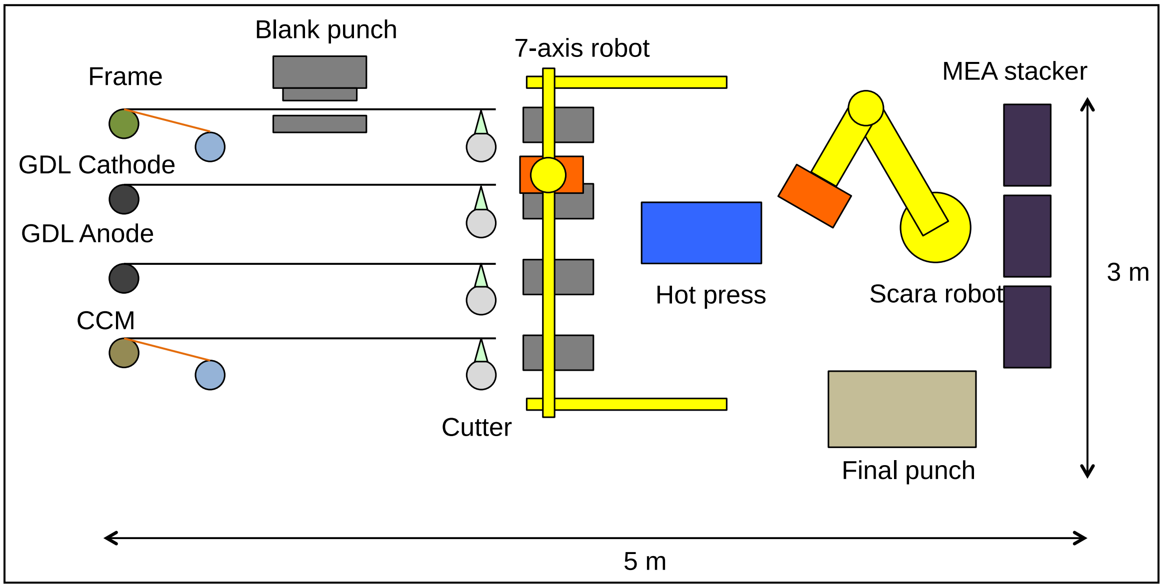
- 1 roll for the frame, but 2 frame sheets needed per MEA
- Frame footprint: 36.25cm x 10cm (+1cm border) = 459cm^2
- Frame actual area = frame footprint – active area – manifold areas = 155cm^2 (304cm^2 scrap area)

The required dimensions of the frame are derived from the functional specifications to be 38.25cm (L) x 12cm (H), or 2cm larger on each side than compared to the bipolar plate (for web handling reasons). The final material area of the frame is given by the following: original frame size – active area – channel areas, or 155 cm^2. The frame has 2 frame sheets per cell that are laminated together. One roll is assumed for the frame process, but 2 frame sheets are needed per MEA.

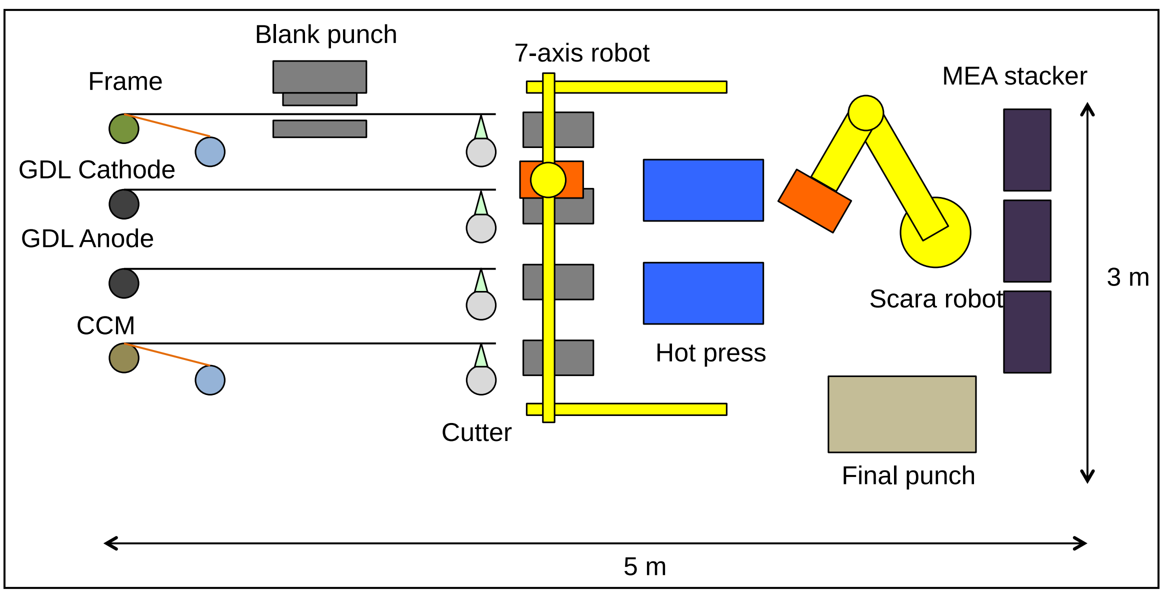
4.3.2 Frame Manufacturing

The MEA frame flow (Fig. 4.12) has three input roll lines for each of the MEA constituent layers (GDL Cathode, GDL Anode, and CCM) and an input roll for the frame film. The purchased frame film comes coated with an adhesive and is protected by a backing layer that is peeled away during processing. The GDL and CCM rolls are cut to size with cutters while the frame material is blank punched to expose the active area and cut to the appropriate size. A seven-axis robot "picks and places" the frame, GDL and CCM layers to form each MEA stack. Adhesive material is assumed be pre-coated on the frame material. The MEA is hot pressed and then placed on a final punch tool to punch the manifolds and to define the final MEA size. MEAs are then placed on a stacker and the robot arm is reset. The bill-of-Materials for MEA frame/seal is shown in Table 4.15.

Configuration B has a 25% lower cycle time and two hot presses versus a single hot press station for configuration A.



(a) Configuration A



(b) Configuration B

Figure 4.12. MEA process flow: (a) configuration A and (b) configuration B.

Component		Material	Cost ($/m2)	Comments
Frame	Frame+ adhesive	Polyethylene naphthalate (PEN)	5	Approx. from ref (CES 2012)
	Backing Layer	Fluorinated ethylene propylene (FEP)	10	Approx. from ref (CES 2012)
CCM				To determine scrap cost
GDL				To determine scrap cost

Table 4.15. Bill-of-Materials for MEA frame/seal.

4.3.3 Process Parameters

The installation factor and maintenance factor are assumed to be 1.4 and 0.1 respectively. These quantities are used to find the capital and maintenance costs by multiplying them by the initial capital cost. The cost of in-situ or ex-situ quality control and inspection is not included.

Yield assumptions (by number of cells) are assumed to increase from 95% at low volume to 99.9% at high volumes with the following dependence: O(1K)=95%, O(10K)=97%, O(100K)=98%, O(1M)=99%, O(10M)=99.5%, O(100M)=99.9%. The base shift times for workers is assumed to be 7 hours.

4.3.4 MEA Frame/Seal Cost Summary

Machine Rates:

Machine rates are summarized below for the roll cutter (Table 4.16); other machine rates for other modules (frame roll and cutter, robotic arms, hot presses, and tray unloader) can be found in Appendix C. For comparison of the different machine rates used in the manufacturing line, a summary table is also included here for all of these machine rates (see Table 4.17).

<u>CCM, GDL Anode, GDL Cathode Roll + Cutter (same cost parameters):</u>

System Size (kW)	100			
Volume (Stacks/yr)	100	1000	10000	50000
Configuration	B	B	B	B
No. of Tools	1	3	25	123
Cycle time per MEA (sec)	6	6	6	6
Power Consumption (kW)	5	5	5	5
Initial Capital ($)	64200	192600	1605000	7896600
Initial System Cost ($)	89880	269640	2247000	11055240
Depreciation ($/yr)	4194.40	12583.20	104860.00	515911.20
Amortized Capital ($/yr)	13257.05	39771.16	331426.29	1630617.37
Salvage Value ($/yr)	115.95	347.86	2898.80	14262.08
Property Tax ($/yr)	354.38	1063.15	8859.60	43589.23
Maintenance Cost ($/yr)	946.93	2840.80	23673.31	116472.67

Energy Cost ($/yr)	161.92	1589.49	15894.90	79474.49
Machine Rate ($/hr)	**16.34**	**5.12**	**4.30**	**4.23**
Capital ($/hr)	15.10	4.62	3.85	3.78
Operational ($/hr)	1.24	0.51	0.45	0.45

*Includes cost of the roller load and cutter

Table 4.16 Machine rates for CCM, GDL anode and GDL cathode roll cutters.

Summary of Machine Rates

100kW	Production Volume (Systems/yr)			
	100	**1000**	**10,000**	**50,000**
CCM, GDL Anode, GDL Cathode Roll + Cutter (same cost parameters)	16.6	5.20	4.36	4.30
Frame Roll + Cutter	25.08	7.98	6.73	6.63
Robotic Arm	24.62	8.47	7.28	7.19
Seven-Axis Arm	29.18	10.18	8.78	8.67
Hot press (each)	57.91	19.90	17.11	16.89
Final Blank Press	13.99	4.48	3.79	3.73
MEA Tray Unloader	4.13	1.28	1.07	1.05

Table 4.17. Summary of all machine rates ($/hr) used in making MEA frame.

Overall cost results show the frame/seal process decreases from about $14 per MEA at a volume of 10,000 MEAs per year (about 1MW annual production) to under $2 per MEA at high volume (see Fig. 4.13 below). At higher volumes, scrap costs are over 50% of the frame/sealing costs. Platinum recovery is assumed to be 90% but even with this high recovery percentage of Pt, scrapped MEAs are very costly since other materials will be scrapped (e.g. GDL, membrane and sealing material). Moreover, all associated processing and capital cost investments will be lost as every step in making MEA shares a part of capital and operational costs. Tables 4.18 and 4.19 show detailed cost analysis for MEA frame which include material, labor, operational, building, capital and scrap cost components.

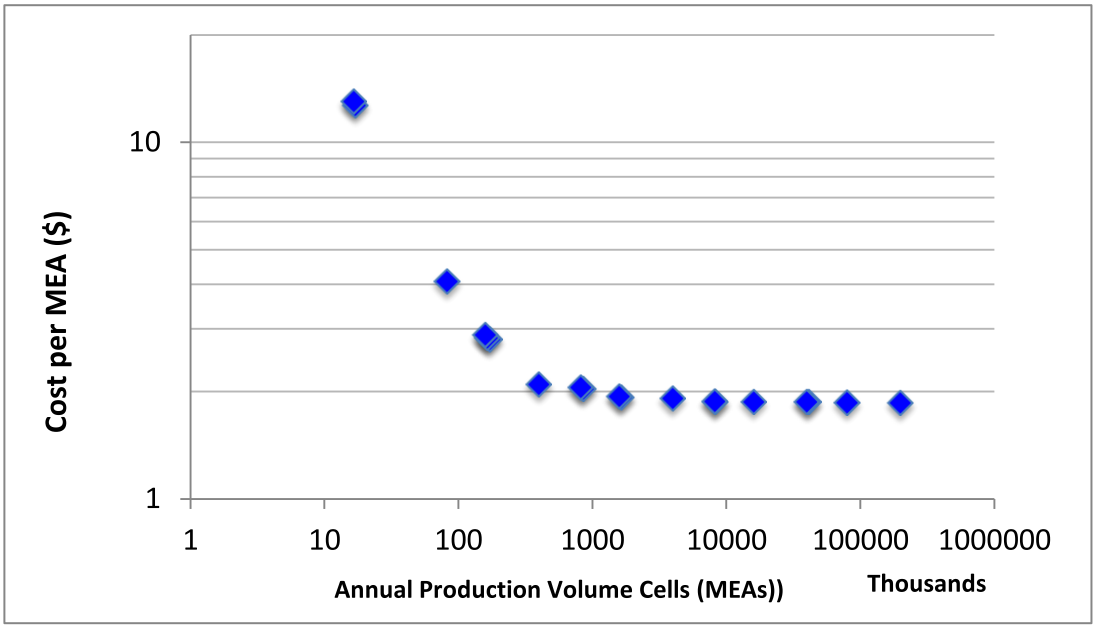
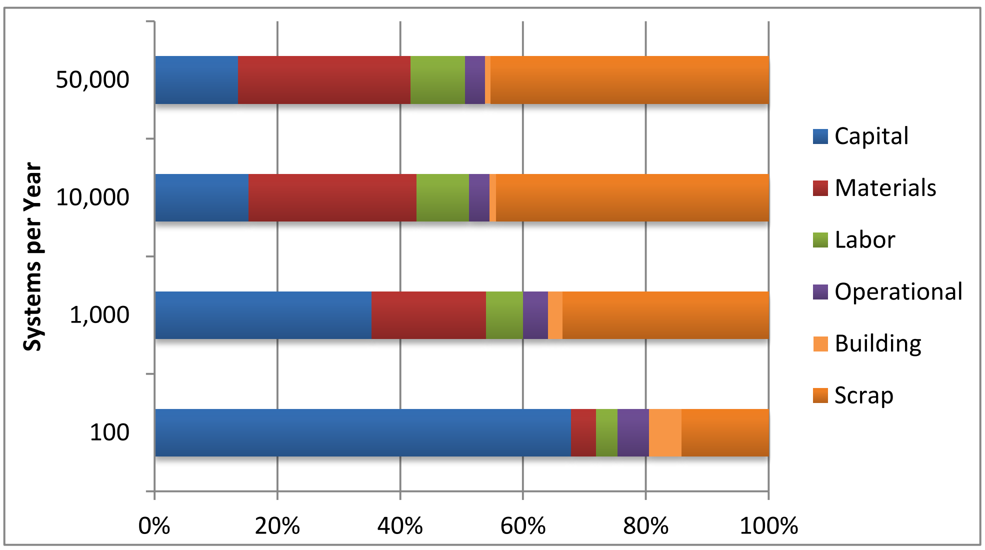
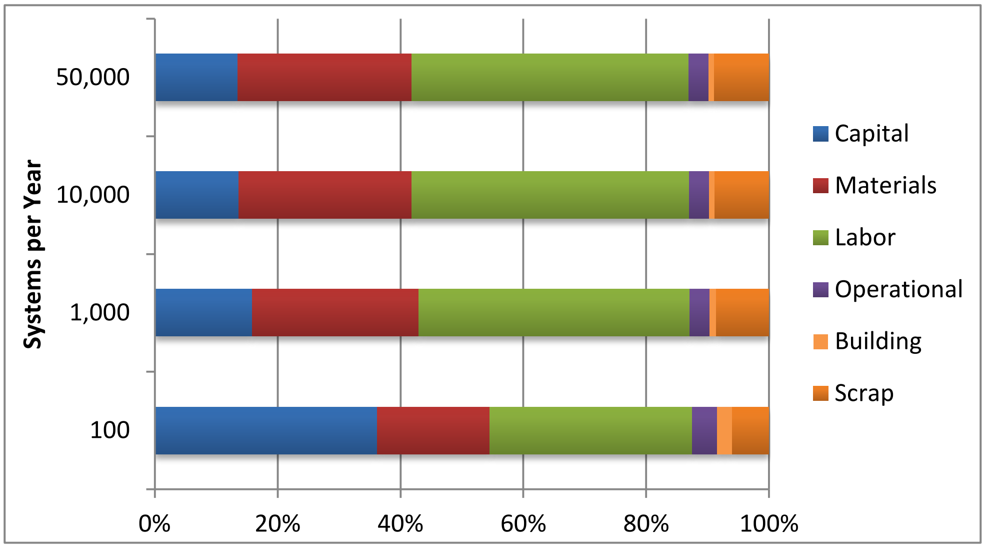


Figure 4.13. Cost vs. production volume for MEA seal/frame.



a) MEA frame/seal Cost breakdown for 10 kW system



b) MEA frame/seal Cost breakdown for 100 kW system

Figure 4.14. MEA frame/seal cost breakdown as a function of annual production volume for: (a) 10kW system; and (b) 100kW system.

System Size (kW)	10			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/Part)	0.53	0.53	0.53	0.53
Labor ($/Part)	0.45	0.17	0.17	0.17
Process: Capital ($/Part)	8.83	1.00	0.30	0.26
Process: Operational ($/Part)	0.67	0.11	0.06	0.06
Process: Building ($/Part)	0.69	0.07	0.02	0.02
Material Scrap ($/Part)	1.84	0.95	0.86	0.85
Total ($/Part)	**13.01**	**2.83**	**1.93**	**1.88**

Table 4.18. MEA frame cost analysis for 10kW CHP system with reformate fuel.

System Size (kW)	100			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/Part)	0.53	0.53	0.53	0.53
Labor ($/Part)	0.17	0.17	0.17	0.17
Process: Capital ($/Part)	1.04	0.31	0.26	0.25
Process: Operational ($/Part)	0.12	0.06	0.06	0.06
Process: Building ($/Part)	0.07	0.02	0.02	0.02
Material Scrap ($/Part)	0.95	0.85	0.85	0.84
Total ($/Part)	**2.88**	**1.94**	**1.87**	**1.86**

Table 4.19. MEA frame cost analysis for 100kW CHP system with reformate fuel.

4.4 Bipolar Plate Analysis

Typically, fuel cell plate vendors/developers have used compression molding where resin or polymer materials are blended with conductive filler material; or embossing GRAFOIL® flexible graphite (Ballard Power Systems) where graphitic carbon is impregnated with resin. Often, thermal treatment is done after molding to completely cure the material and/or to reduce VOC content. Recently metal plates have also been considered, particularly in the automotive applications; however, a less established plate lifetime (about 5000-6000 hours) suggests that using more standard graphite composite-based plates are a more durable option. Both approaches will be analyzed below.

Injection molding (IM) is better suited to high volume manufacturing than compression molding as it offers lower cycle times and established process technology with good dimensional control. However, material issues can make injection molding challenging for fuel cell applications. For example conductive filler is needed for better conductivity that adds to material costs and also makes the technique more difficult due to higher viscosity and poorly controlled melt properties.

As plates get larger in area, tolerances and control of plate planarity and flatness become larger concerns and need to be evaluated for injection molding. Additionally, plate brittleness can lead to cracking and therefore plates may need added thickness, which results in undesirable volume and weight. Nonetheless, work from the Center for Fuel Cell Technology (ZBT) at the University of Duisburg-Essen (see for example Heinzel, et al.2004, and Yeetsorn 2008) has achieved IM plates with good electrical and physical performance with a slight increase in plate thickness (2mm).

As noted in Yeetsorn (2011), research and development is needed for better composite materials with maximal electrical conductivity. One cited pathway is the development of more advanced material with the proper conductive network structure. Here an analysis of injection-molded plates is presented for cost comparison with metal plates. Injection molding was modeled instead of compression molding since this work is targeted for higher volume and injection molding is expected to yield lower costs.

This implicitly assumes that continued development will occur in composite materials with conductive fillers, potentially including nanostructured materials that will allow injection molding to be viably employed. Stationary applications allow for slightly thicker plates since volume and weight are not as stringent concerns as that for the automotive application. Slightly thicker plates may also achieve better quality in terms of dimensional tolerances, plate stability, and yield.

4.4.1 Carbon Bipolar Plate Design

The total bipolar plate area (Fig. 4.15) is assumed to be 362.5cm^2, which is derived from the functional specifications above and includes the area for MEA bonding, frame, and header channels. Maximum half-plate thickness is taken to be 1.5mm and total BIP mass at 137.4g.

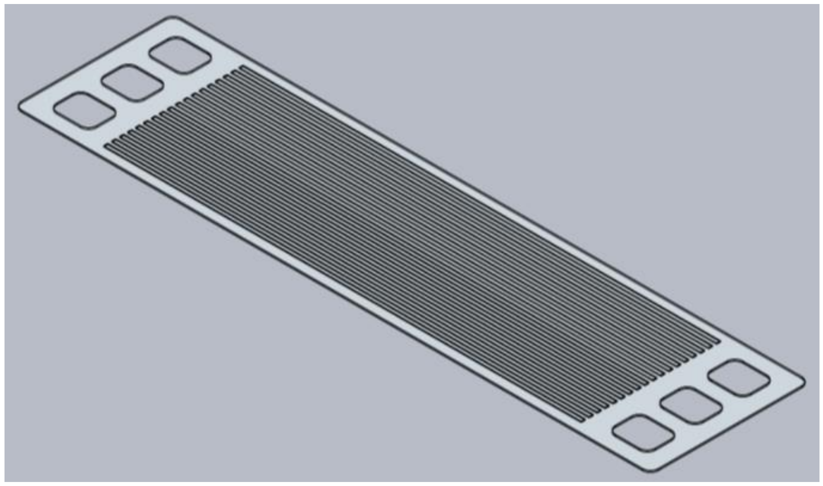


Figure 4.15. Bipolar plate (BIP).

4.4.2 Carbon BIP Manufacturing

The process flow is shown in Figure 4.16 below. We assume that input material (composite) is already mixed and pelletized. Injection molding machine size, electrical power, and cycle time are determined by a model created by UC-Berkeley/LMAS (Chien 2013) that results in cycle times estimated to be 30.6 seconds per half plate in a lower volume configuration and 16.1 seconds with a higher batch size and two injection cavities. Injection molding is followed by a deflashing and shot-peening step. The shot-peening step treats the surface to reduce gas permeability and become a slightly compressive layer. This step is *in lieu* of a separate resin-curing step typically used to treat the surface. A screen printer is used to coat epoxy on the half plates to form bipolar plates followed by an oven-curing step and then a final inspection step. Potential plate cleaning steps could also be envisioned but were not included in this analysis due to the uncertainty in cleaning requirements.

Plate materials are assumed to be a combination of polypropylene binder with a mixture of graphite and carbon black conductive filler. Process flow equipment is shown for two configurations, for low and high volume. Equipment costs are fairly evenly distributed between process modules with the injection-molding machine contributing the largest capital cost.

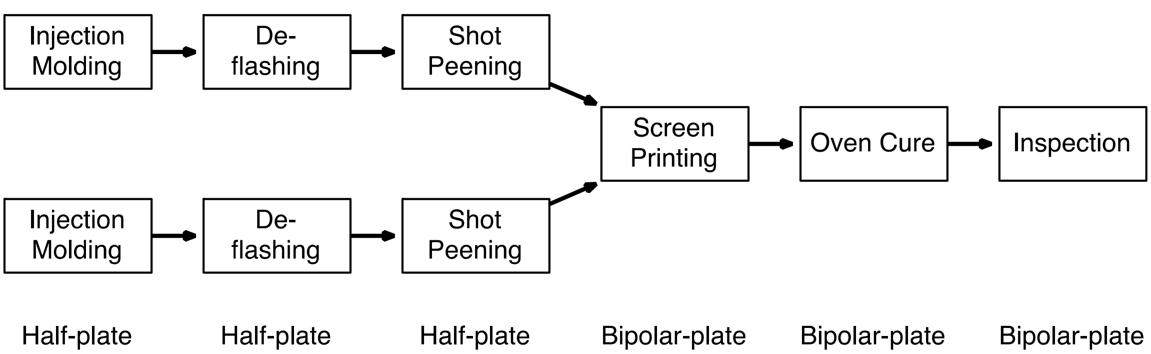


Figure 4.16. Process flow of BIP manufacturing.

Component		Material	Cost ($/kg)	Cost ($/L)	Comments
Half Plate	Binder	Polypropylene	1.597		2011 market price
	Filler 1	Graphite	6.761		2011 market price
	Filler 2	Carbon Black	6.35 3.833		DTI2010 Wholesale Alibaba.com
Bipolar Plate	Adhesive	Carbon Epoxy		97.38	Eccobond 60L

Table 4.20. Bill of materials for composite bipolar plates.

	Cost ($x1K)	Power (kW)
Injection Molding Machine (300T, 650T)	(290, 455)	(43, 119)
De-flashing (manual, cnc plotter)	(0, 150)	(0, 8)
Shot Peening Machine	150	10
Screen Printing Machine (2 cavity, 4 cavity)	(150, 200)	3.5
Hot Oven (90 plates, 180 plates)	(110, 165)	(2.4, 3.4)
Inspection (manual, automated)	(0, 200)	10

Table 4.21. Equipment for bipolar plate manufacturing line.

Process Parameters:

Web width varies between 0.5m, 1m, and 1.5m depending on production volume. Yield assumptions for the bipolar plate caps the low end yield at 60% with high end yield at 99.5% (see Fig. 4.17 below). Yield loss due to cracking or defects is a potential concern and was one factor for assuming a relatively low yield at low volume. Setup time starts at 60 minutes and exponentially decays after the 100,000 plate/year mark.

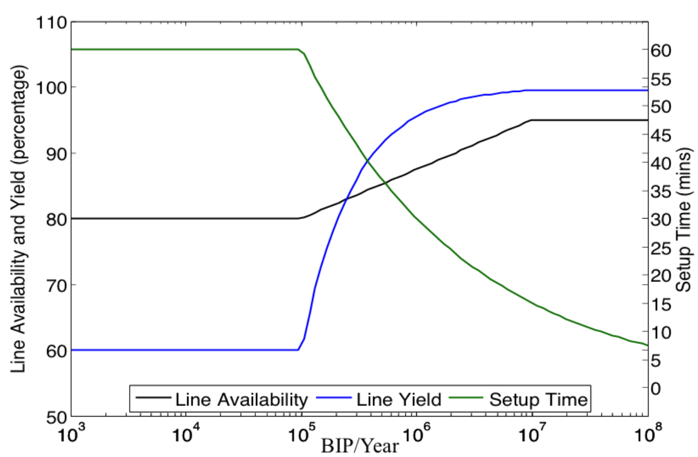


Figure 4.17. Line availability, line yield and set up time for carbon composite bipolar plates.

The process model does not include material mixing, extruding, and pelletizing since it is assumed that material is purchased in pellet form. Production batch size is taken to be 90 bipolar plates at low volume and 180 bipolar plates at high volume. The two manufacturing configurations are described in the Table 4.22 below.

Configuration A (batch size of 90 BIP's):	Configuration B (batch size of 180BIPs)
All transfer times (from station to the next) was assumed to be an average of 20 seconds	Robotic transfer (from one station to the next) at 2s per transfer
<u>Injection Molding:</u> Horizontal, semi-automated, 340-ton injection molding Assume input material (composite) already mixed and pelletized Machine size, electrical power, and cycle-time is determined by a model created by UC Berkeley/LMAS Cycle-time ~30.6s per half-plate	<u>Injection Molding:</u> Same description as configuration A 680-ton at 2 cavities (i.e. two half-plates) Cycle-time: ~32.3 per cycle or 16.1s per half-plate
<u>De-flashing:</u> Operator hand de-flash (no capital cost) Cycle-time: 15s per half-plate	<u>De-flashing:</u> Automated de-flashing on CNC plotter Cycle-time: 5s per half-plate
<u>Shot Peening:</u> For surface treatment (helps reduce gas permeability) Cavity size of 4 half-plates Cycle-time: 30s or 7.5s per half-plate	<u>Shot Peening:</u> Same as above
<u>Screen Printing:</u> DEK Horizon i01 (same is DTI2010) Cavity size of 2 half-plates Cycle-time: 9.63s per pass or 4.82s per half-plate	<u>Screen Printing:</u> Europa VI (same as DTI2010) Cavity size of 4 half-plates Cycle-time: 12.26 per pass or 3.1s per half-plate
<u>Oven Cure:</u> Cure epoxy adhesive Fits 180 half-plates (or 90 BIP's) Cycle-time: 1.5hours at 150C	<u>Oven Cure:</u> Fits 360 half-plates (or 180 BIP's) Cycle-time: 1.5 hours at 150C
<u>Inspection:</u> Operator hand inspection per BIP Cycle-time: 10s per BIP	<u>Inspection</u>: Automated dual optical/camera inspection (for both sides of plate) Cycle-time: 2s per BIP

Table 4.22. Two manufacturing configurations for making composite BIP.

4.4.3 Carbon Plates Costing Summary

A cost summary for the 10 and 100 kW systems is shown in the tables below. Similar tables for the 1, 50, and 250 kW systems are compiled in Appendix C. All units are in ($/BIP Plate).

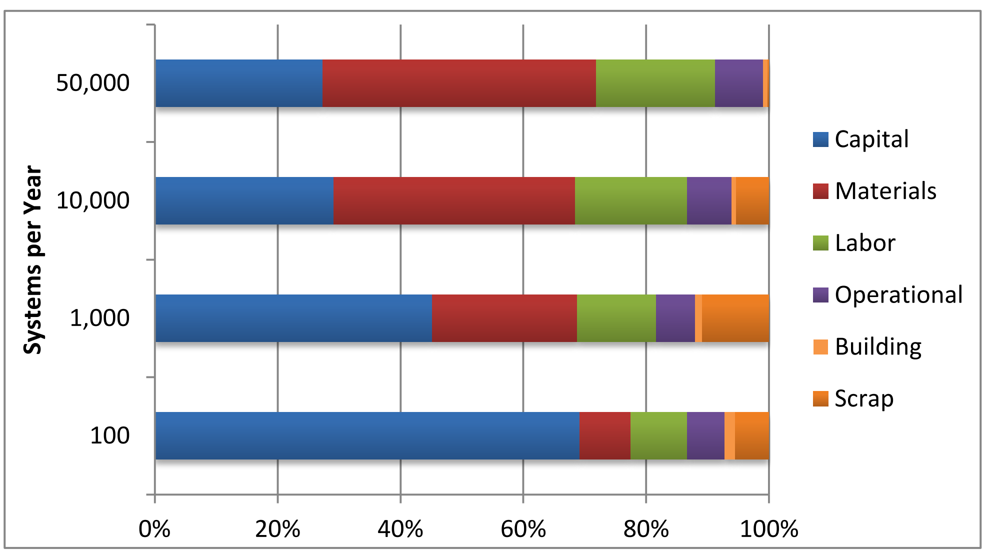
System Size (kW)	10			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/BPP)	2.10	1.84	1.43	1.26
Labor ($/BPP)	2.36	1.01	0.66	0.55
Process: Capital ($/BPP)	17.64	3.53	1.06	0.78
Process: Operational ($/BPP)	1.53	0.49	0.26	0.22
Process: Building ($/BPP)	0.45	0.09	0.03	0.02
Material Scrap ($/BPP)	1.40	0.85	0.19	0.01
Total ($/BPP)	**25.48**	**7.81**	**3.63**	**2.84**

Table 4.23. Costing summary of carbon plates for 10kW system.

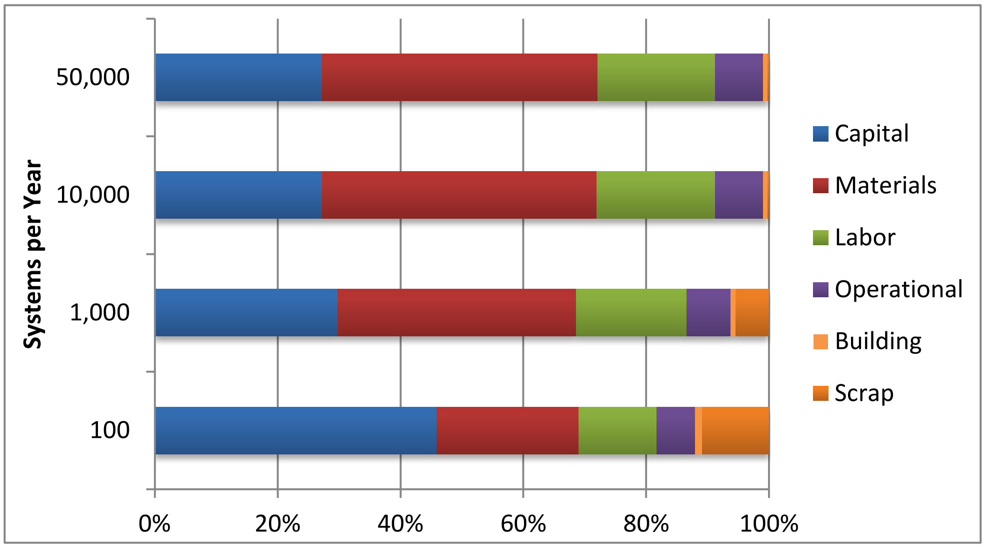
System Size (kW)	100			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/BPP)	1.85	1.43	1.26	1.26
Labor ($/BPP)	1.01	0.66	0.55	0.54
Process: Capital ($/BPP)	3.67	1.10	0.77	0.77
Process: Operational ($/BPP)	0.50	0.27	0.22	0.22
Process: Building ($/BPP)	0.09	0.03	0.02	0.02
Material Scrap ($/BPP)	0.86	0.20	0.01	0.01
Total ($/BPP)	**7.99**	**3.69**	**2.83**	**2.82**

Table 4.24. Costing summary of carbon plates for 100kW system.

At the highest volumes, the cost per plate converges to $2.80. The cost breakdown is shown in bar graph form below.



a) Cost breakdown of carbon plates for 10kW system



b) Cost breakdown of carbon plates for 100kW system

Figure 4.18. Fraction of carbon plate costs as a function of annual production volume for: (a) 10kW system; and (b) 100kW system.

Figure 4.18 shows the cost summary in $/kW for 10kW and 100kW systems. This figure shows that at low production volume (10kW, 100 annual units), capital cost makes up about 65% of the total cost while material cost makes up 10%. At higher volumes (100kW, 50,000 annual units), capital costs only make up about 25% of the total cost while material cost makes up 45%.

4.5 Metal Bipolar Plate Analysis

Metal plates are considered here as another process flow option for bipolar plates. Metal plates have several potential advantages over carbon plates: (1) higher yield and less cracking; (2) potential to be thinner and lighter; (3) higher electrical and thermal conductivity; and (4) potentially more re-usable at stack end-of-life. A key requirement however is the need for a robust coating over the metal to ensure that the plates that can withstand the corrosive environment of the fuel cell stack operating conditions, and metal plates have yet to demonstrate lifetime beyond several thousand hours. Since stack lifetimes are less stringent in automotive applications than stationary applications such as CHP, and since stack volume and weight are also key considerations, metal plates have been an active area for research and development in fuel cells for the automotive space. For this work, metal plate manufacturing costs are characterized, with the intention of initially targeting the backup power application area where lifetimes are less stringent than the CHP application.

4.5.1 Metal Bipolar Plate Design

The metal BIP area is the same as above for the carbon plate (362.5cm^2). We also assume six manifolds (three on each side for hydrogen, oxygen, and coolant) with each manifold 3cm (L) x 2.5cm (H). Channel design assumes 27 channels with land and channel width at 1.5mm. Other physical properties are as follows:

- Derived from the functional specifications (259cm^2 of active area), → 32.375cm (L) x 8cm (H)

- Assume 5mm edge for MEA bonding -> 300.375cm^2 of MEA area
- Assume 5mm top and bottom for frame and 14.375mm (each side) for header channels
    - Total frame (hence BIP) area → 362.5cm^2; 36.25cm (L) x 10cm (H)
- Manifolds: 6 (3 on each side for hydrogen, oxygen, and coolant)
    - Each manifold 3cm (L) x 2.5cm (H)
- Number of channels: 27
    - Land and channel width: 1.5mm
- Sheet metal thickness: 0.1mm.
- Coating thickness: 2um
- Total BIP mass: 51.5g

For reference, the carbon plate thickness is 3mm and total BIP mass is 137g.

4.5.2 Process Flow Description

The process flow consists of the following modules: (1) stamping of a sheet roll of stainless steel, (2) cleaning and drying, (3) laser welding to seal the plates, (4) cleaning and drying, (5) physical vapor deposition (PVD) of the coating, (6) and a final inspection (Fig. 4.19). The coating step is expected to be the key cost limiter for metal plates, followed by the laser welder since the other steps are more standard process modules. Numerous protective coating processes have been proposed including thermal nitridation, PVD, CVD, and passive film modification. The PVD process was chosen here for good throughput, high purity, uniformity, and defect control. In particular, cathodic-arc deposition has been shown to have relatively high throughputs and capability of processing large batches (Wang 2001). However, the major drawback is the relatively high capital expenditure. The two proposed configurations are described below (for low and high volumes).

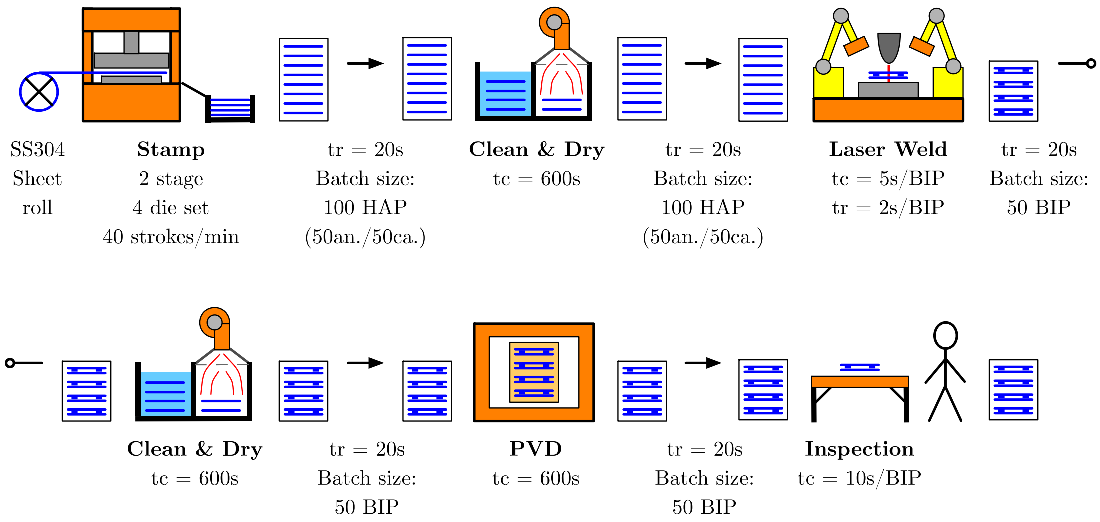
<u>Configuration A (Batch size of 50 BIPs), Configuration B (Batch size of 100BIPs):</u>

All transfer times (from station to the next) were assumed to be an average of 20 seconds

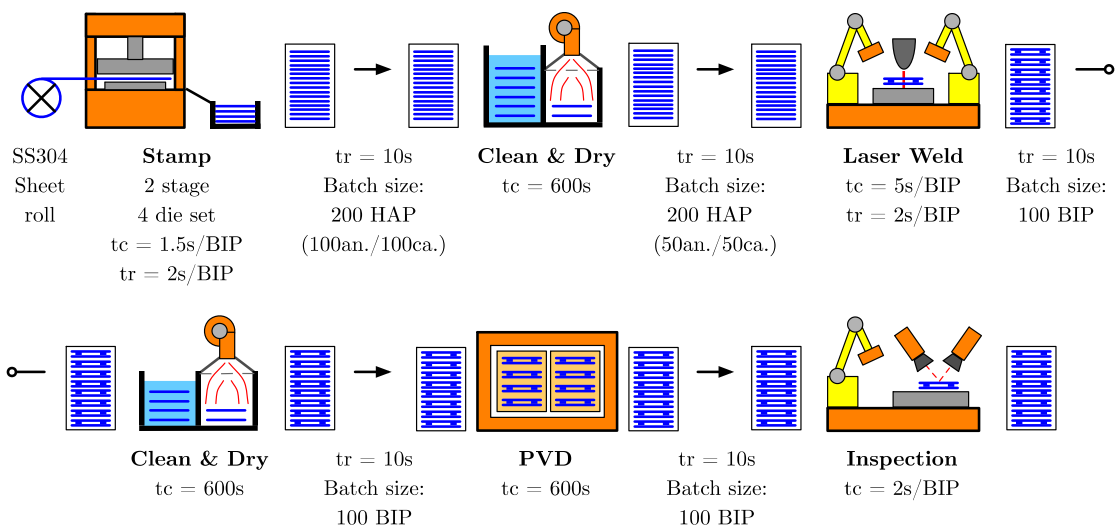
<u>Stamping:</u>

- Tool size: 300 tons
- 2-stage at 1.5s each per plate
- 2 second transfer time per plate
- Number of dies: 4 (2-anode, 2-cathode)
- Die life: 600,000 cycles (Sinha and Yang, 2010)
- Die max refurbish: 2 @ $50,000 ea. (Sinha and Yang, 2010)

<u>Clean/Dry 1:</u>
600 seconds per batch
<u>Weld:</u>
5 seconds weld per plate
2 seconds transfer time per plate
<u>Clean/Dry 2:</u>
600 seconds per batch
<u>PVD Coat:</u>
600 seconds per batch
<u>Inspection:</u>
Manual: 10 seconds per BIP
Auto: 2 seconds per BIP



a) Process flow A



b) Process flow B

Figure 4.19. Process flow for manufacturing metal plates (HAP=half-plates; an.=anode, ca.=cathode).

Component	Section	Material	Cost ($/kg)	Cost ($/L)	Comments
Half Plate	Substrate	SS304	11	n/a	In 2010 dollars (James et al., 2010)
	Coating	Cr/N	50	n/a	In 2010 dollars

Table 4.25. Bill of materials for metal plates.

Chromium nitride (CrN) is chosen as the coating for its relatively low cost compared to other coatings, exceptional hardness, and excellent resistance to corrosion. CrN has been evaluated to have better performance than other common coatings such as TiN and ZrN and CrN coated SS304 has been found to be superior to those of CrN coated SS316 (Zhang 2010). Noble metals (e.g., gold) offer the best combination of electrical conductivity and corrosion-resistance; however, they are expensive to use in practice (James et al., 2010).

Equipment	Cost ($x1K)	Power (kW)	Comments
Dual die stamper	480	17	Power calculated
Cleaner/Dryer (A)	500	10	Power approximated
Cleaner/Dryer (B)	750	15	Power approximated
PVD (A)	1920	504	Power calculated
PVD (B)	2875	756	Power calculated
Auto inspection	250	10	Power assumption
Auto Welder	1125	31	Power approximated

Table 4.26. Equipment cost (in 2010 dollars) required for metal bipolar plates manufacturing line.

4.5.3 Metal Plates Manufacturing Process Parameters

The process parameters are shown in Table 4.27. Scrap percentage, setup time, line availability, and process yield are all functions of bipolar plate volume. At low volumes (< 100,000 BIP/yr), scrap percentage is assumed to be 60%, setup time to be 60 minutes, line availability to be 80% and process yield to be 85%. At high volumes (>10,000,000 BIP/yr), scrap percentage is estimated to be 85%, setup time to be 5 minutes, line availability to be 95%, and process yield to be 99.5%. For volumes between 100,000 and 10,000,000 BIP/yr, the process parameter was found through exponential interpolation.

Size (kW)	Volume	Half-Plates (x1000)	Line Config.	Tool Run-Time (h)	No. Workers	Setup Time (min)	Line Availability	Process Yield
1	100	3.4	A	13.78	3	60	80.00%	85.00%
	1000	34	A	137.8	3	60	80.00%	85.00%
	10000	340	A	1,321	3	31	83.74%	88.63%
	50000	1,700	A	3,580	3	13.01	88.92%	93.65%
10	100	33	A	133.7	3	60	80.00%	85.00%
	1000	330	A	1,284	3	31.5	83.64%	88.54%
	10000	3,300	B	6,794	3	9.09	91.15%	95.80%
	50000	16,500	B	32,710	5	5	95.00%	99.50%
50	100	163.4	A	651.1	3	46.03	81.48%	86.44%
	1000	1,634	A	3,446	3	13.29	88.79%	93.52%
	10000	16,340	B	32,390	5	5	95.00%	99.50%
	50000	81,700	B	161,900	21	5	95.00%	99.50%
100	100	317.4	A	1,236	3	32.17	83.52%	88.42%

	1000	3,174	B	6,543	3	9.29	91.02%	95.67%
	10000	31,740	B	62,910	9	5	95.00%	99.50%
	50000	158,700	B	314,600	41	5	95.00%	99.50%
250	100	792	A	2,990	3	19.64	86.42%	91.23%
	1000	7,920	B	15,820	5	5.67	94.18%	98.71%
	10000	79,200	B	157,000	21	5	95.00%	99.50%
	50000	396,000	B	784,900	99	5	95.00%	99.50%

Table 4.27. Manufacturing parameters as a function of system size and annual volume for manufacturing line of metal plates.

4.5.4 Metal Plates Cost Summary

A cost summary for the 10 and 100 kW systems is shown in the Tables 4.28 and 4.29, respectively. Similar tables for the 1, 50, and 250 kW systems are compiled in the Appendix C. All units are in ($/BIP Plate).

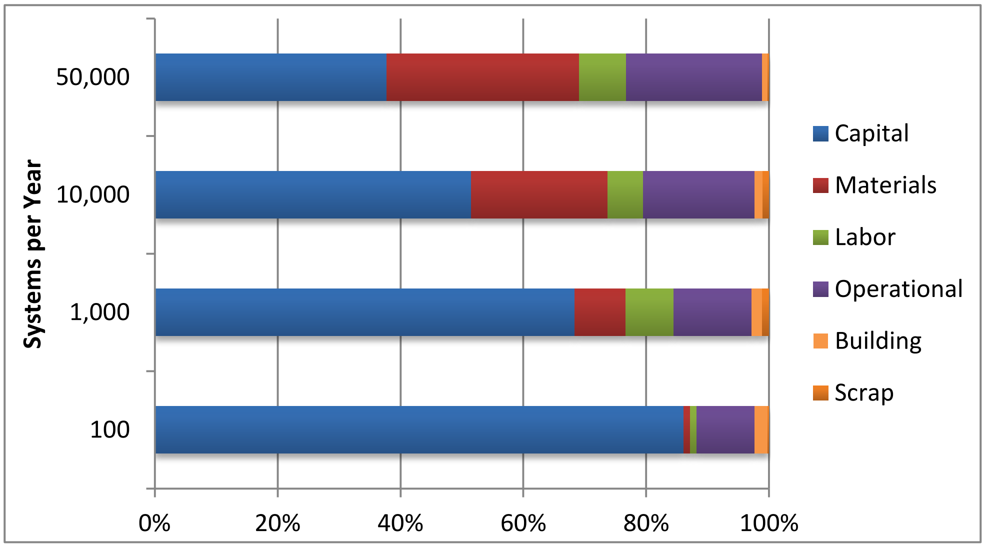
System Size (kW)	**10 kW**			
Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/BIP)	0.80	0.77	0.71	0.68
Labor ($/BIP)	0.77	0.72	0.19	0.17
Process: Capital ($/BIP)	63.16	6.32	1.65	0.82
Process: Operational ($/BIP)	6.88	1.17	0.58	0.48
Process: Building ($/BIP)	1.60	0.16	0.04	0.02
Material Scrap ($/BIP)	0.14	0.10	0.03	0.00
Total ($/BIP)	**73.35**	**9.24**	**3.20**	**2.18**

Table 4.28. Costing summary of metal plates for 10kW CHP system with reformate fuel.

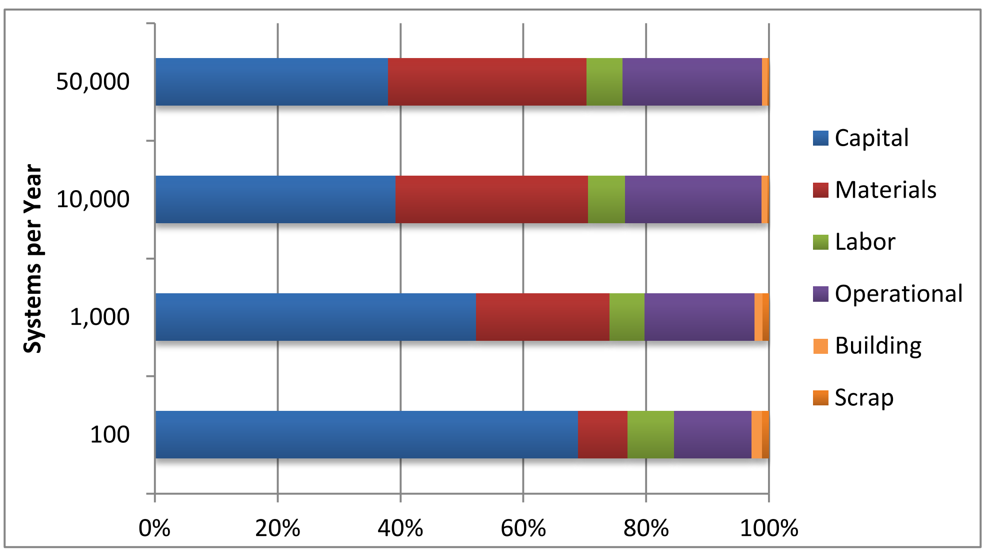
System Size (kW)	**100 kW**			
Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/BIP)	0.77	0.71	0.68	0.68
Labor ($/BIP)	0.72	0.19	0.13	0.12
Process: Capital ($/BIP)	6.57	1.71	0.86	0.81
Process: Operational ($/BIP)	1.20	0.59	0.49	0.48
Process: Building ($/BIP)	0.17	0.04	0.02	0.02
Material Scrap ($/BIP)	0.10	0.03	0.00	0.00
Total ($/BIP)	**9.52**	**3.27**	**2.18**	**2.12**

Table 4.29. Costing summary of metal plates for 100kW CHP system with reformate fuel.

These tables show the relationship between production volume and cost. As the annual production of bipolar plates increases, the bipolar plate cost decreases. At the highest volumes, the cost per plate converges to $2.10/BIP. Bar graphs (Fig. 4.20) show the cost breakdown.



a) Cost breakdown of metal plates for 10kW system



b) Cost breakdown of metal plates for 100kW system

Figure 4.20. Fraction of bipolar plate costs as a function of annual production volume for: (a) 10kW system; and (b) 100kW system.

Figure 4.20 shows that capital costs dominate for the 10kW system at 100 and 1,000 systems per year and material costs make up 30% of the total plate cost at volumes above 50,000 systems per year. Similarly for the 100kW system, materials costs are about 30-40% of the total cost at volumes above 10,000 systems per year.

4.5.5 Make vs. Buy Analysis for Metal Plates

Throughout the DFMA costing section of this report, costs are calculated with the assumption that each individual part is made in house. This is accurate for high annual production volumes; however, at lower volumes it may be a more economically viable option to purchase some parts from outside vendors. This is the case for the metal bipolar plates.

Metal bipolar plates are fabricated by means of three major processes: stamping, welding, and coating. All three processes are common practices at a sheet metal working facility and therefore the metal plates can be purchased without an overly high markup. This analysis assumes a markup rate of 40% based on our cost estimates for metal plates at high volume.

In many cases, fuel cell manufacturers offer multiple fuel cell system sizes to meet the requirements of different applications in a given market. It is therefore useful to look at the "make versus buy" cost relationship as a function of the total amount of bipolar plates rather than the annual quantity of a specific fuel cell size. This can be done since bipolar plates are compatible with all unit sizes. This relationship between the costs of making the metal plates versus buying them is shown in Figure 4.21.

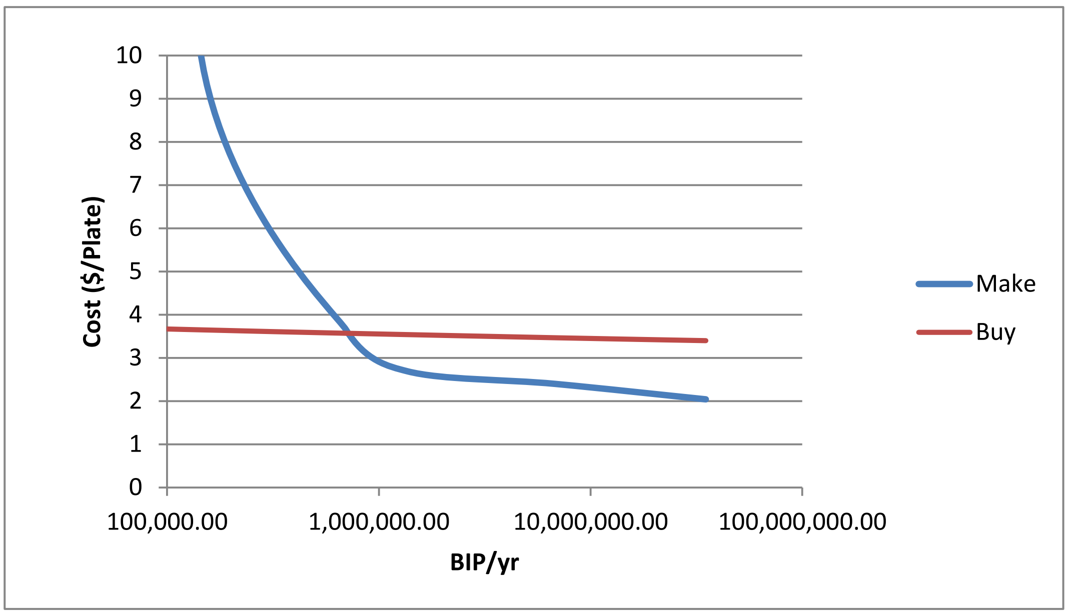


Figure 4.21. Make vs. Buy as a function of BIP/yr.

It can be seen from this figure that at low production volumes, it is cheaper to buy the metal bipolar plates and at higher production volumes, it is cheaper to make the metal bipolar plates. The critical point in which the make option overtakes the buy option is when annual bipolar plate volume exceeds about 800,000 bipolar plates per year.

4.5.6 Metal vs. Carbon Bipolar Plates

A side-by-side cost comparison shows the cost relation between carbon and metal plates. Figure 4.22 shows that metal plates have a much higher initial investment (capital cost), which makes carbon plates the cheaper option for low production volumes. This high metal plate cost at low volumes is driven by the PVD tooling cost. In Figure 4.24, it is easily seen that at high enough volume, the capital cost of the metal plates is spread out enough that metal plates become the cheaper option.

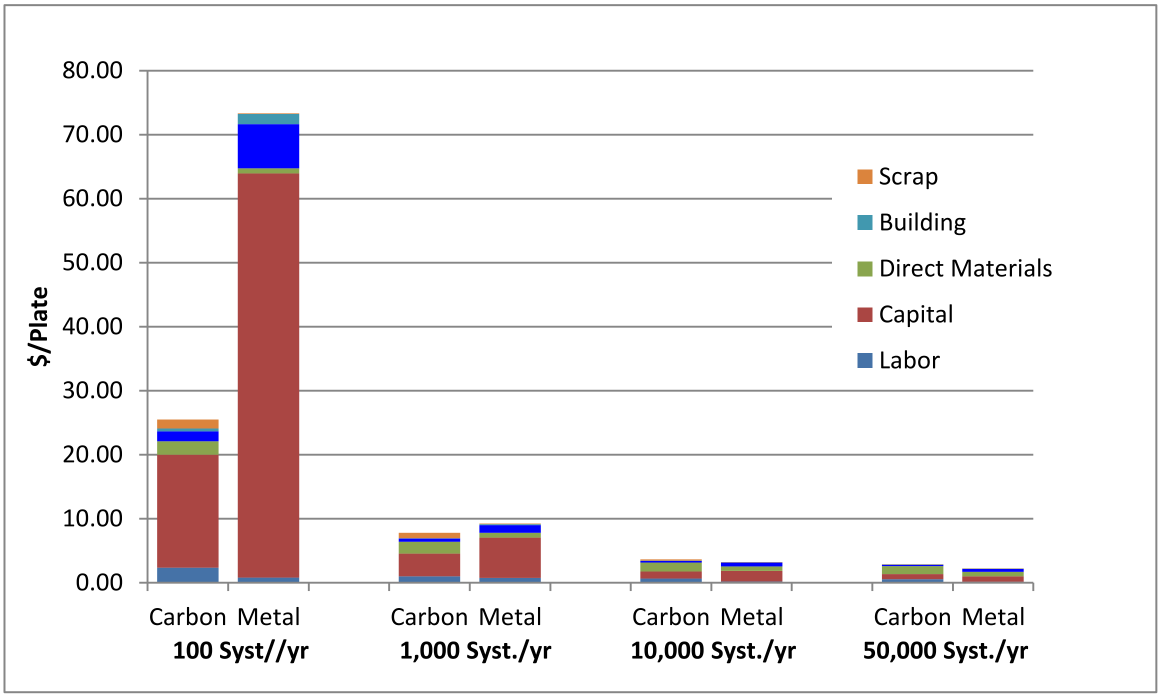


Figure 4.22. Cost Comparison of Metal and Carbon Plates for 10kW Fuel Cell.

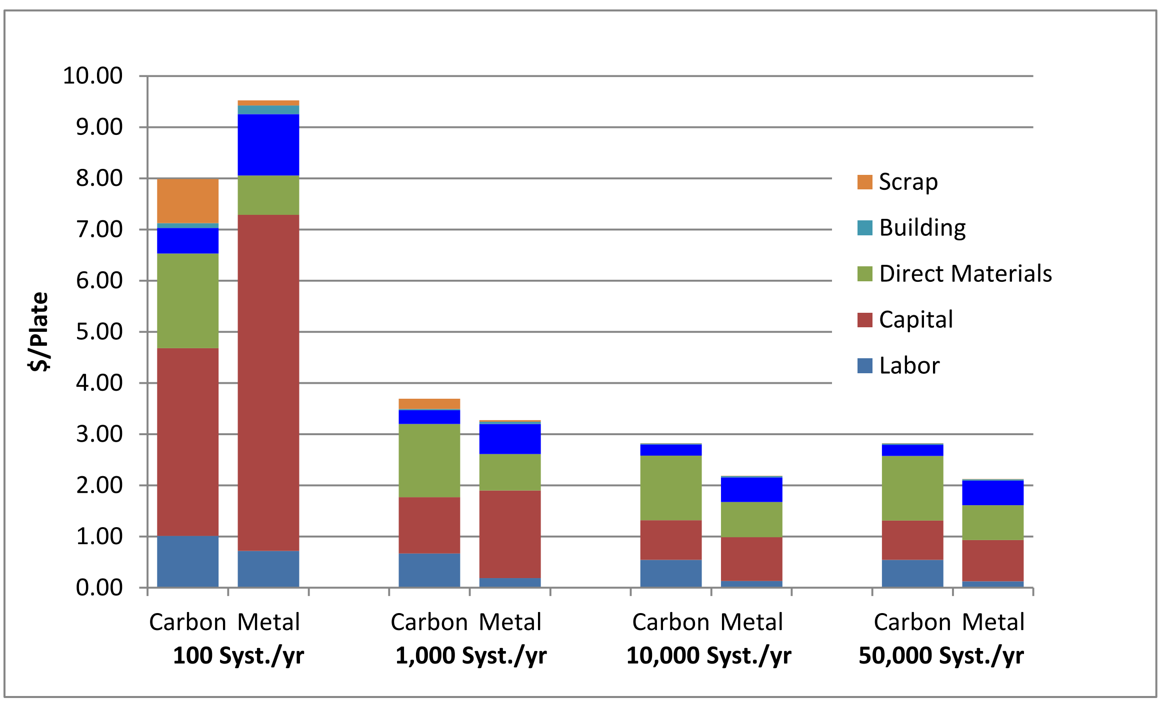


Figure 4.23. Cost Comparison of Metal and Carbon Plates for 100kW Fuel Cell.

Figure 4.24 shows the comparison of metal plates and carbon composite plates as a function of the production volume. It is seen that there is a critical point at about 2,000,000 BIP/year at which metal plates become cheaper to produce than carbon plates.

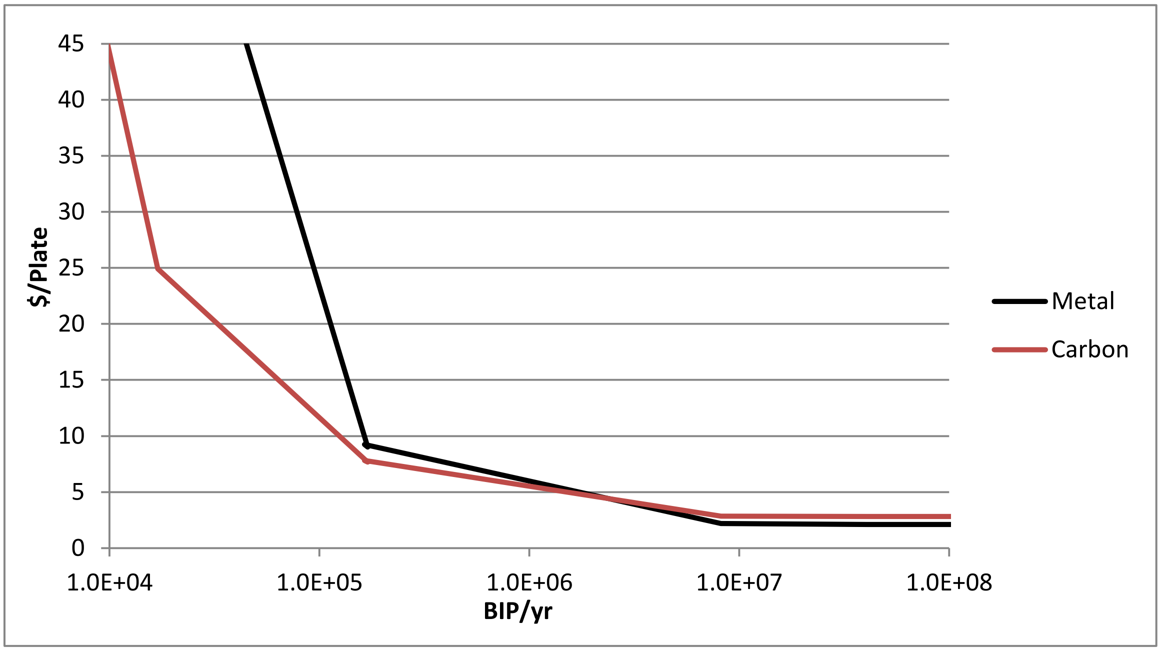


Figure 4.24. Cost Comparison of Metal and Carbon Plates as a function of BIP/yr.

4.6 Stack Assembly Line Cost Analysis Parameters

The process for the stack assembly line is shown in Fig. 4.25. This line combines the framed MEAs with the bipolar plates and assembles the fuel cell stack. It assumes a manual assembly line for low production volumes and semi-automated assembly line for medium production volumes and fully automated assembly line for high production volumes. A line transition is made when a single production line with a lesser degree of automation cannot keep up with production. In the automated case, a robotic feed of plates is followed by screen-printing of gaskets and a UV curing step. The plate/MEAs are then stacked, and compression bands added, followed by a conditioning and testing step.

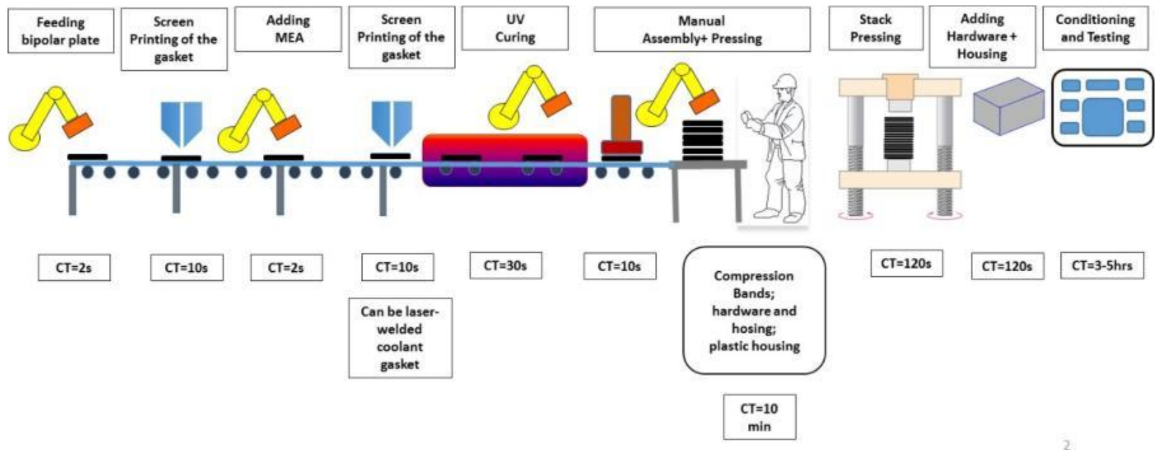


Figure 4.25. Process flow for semi-automatic assembly line.

Stack assembly costs were based on the amortized workstation costs and the estimated times to perform the required assembly process. Three designs of stack assembly were analyzed: manual, semi-automated and fully automated. Selection of assembly line is based on the number of MEA's assembled annually. In this study we have chosen the following design options: if the number of MEA's is less than 100k units annually then manual assembly is chosen; when the number of MEAs falls between 100k and 700k units a semi-automated line is utilized, and when there are more than 700k MEAs then an automated assembly line is installed. The level of automation was chosen based on industry inputs for manual and semi-automated assembly lines. Manual assembly consists of workers individually acquiring and placing each fuel cell element to form the stack: end plate, current collector, bipolar plate, gasketed MEA, bipolar plate, and so on. An entire stack is assembled at a single workstation. The worker sequentially builds the stack (vertically) and then binds the cells with metallic compression bands or tie rods. The finished stacks are removed from the workstation by conveyor belt.

At higher production levels (100-700k MEA's annually), stack assembly is semi-automatic, requiring less time and labor and ensuring superior quality control. This is termed "semi-automatic" because the end components (end plates, current conductors, and initial cells) are assembled manually. A fully automated assembly line is strongly recommended for very high production volumes which exceed 700k units per annum in order to reduce assembly time and to produce higher quality fuel cell stacks.

4.6.1 Stack Assembly Process Parameters

Table 4.30 below summarizes the proposed selection of assembly line, which is based on industry assessment and engineering estimates. If we assume that a 5kW fuel cell system has ~50-60 MEA's, then shifting from semi-automatic to automatic assembly line occurs at a volume that exceeds 11,000 systems per year or 600-750k MEA's.

No. of MEA cells	Assembly line type	Initial capital cost estimate ($)	No. of robots per line	Cost of Robots ($)
<100k	Manual	200,000	0	0
100k-700k	Semi-automatic	500,000	2	100k
>700k	Automatic	1,000,000	7	350k

Table 4.30. Estimated capital cost estimates for manual, semi-automatic and fully automated assembly lines.

Other processing notes:

- A bill of materials along with some suggested suppliers are shown in Table 4.31.
- There is high yield sensitivity at this step and every effort must be made to ensure that this very close to final product is not scrapped. A yield of 99% is assumed.
- Machine footprint is a function of the line width (1.67m), and machine size.
- Cost of each robot is $50,000 (6-axis RX160 robots from Stabuli).
- Index time (or required time to assemble one fuel cell stack) is estimated based on the type of assembly line (example of estimated index times is shown in Table 4.32).

	Price	Vendor	
Compression Band ($/system)	10-24 depending on size of the FC (stacks/system +size of each stack)	N/A	
Silicone Adhesive material	$20/kg	Dana Corporation	
H_2 for conditioning ($/kW)	H_2 density at RT=0.089 g/L, price=$4-5/kg*. Testing and conditioning time 3 hrs. Fuel Utilization 1 kW system: 0.80 SLPM 10 kW system: 0.91 SLPM 50 kW system: 4.54 SLPM 100 kW system: 9.08 SLPM 250 kW system: 22.7 SLPM		$0.01-0.08 /kW
Current Collectors	Rounded shape copper inserts (DFMA analysis using DFMA software gives us a price range between $0.10-0.345 per pcs)		

* http://www.h2carblog.com/?p=461

Table 4.31. Bill of materials for stack assembly.

System Size (kW)	100			
Lines	1	1	1	2
Stacks/Yr	100	1,000	10,000	50,000
Scrap	1%	1%	1%	1%
Overall Yield	99%	99%	99%	99%
Assembly line	Semi-automated	Fully Automated	Fully Automated	Fully Automated

Index Time (min/stack)	49.5	8.8	8.8	8.8
Line Utilization				
Line Width (m)	1.67	1.67	1.67	1.67
Installation factor	1.1	1.1	1.1	1.1
Annual Operation Hours	82.50	146.67	1466.67	3666.67
Required labor	2	2	2	4
Worker Rate	29.81	29.81	29.81	29.81
Building Footprint (m2)	280	280	280	1120

Table 4.32. Stack Parameter and assumptions (100kW) used to calculate assembly cost.

Assembly line Parameters:

System Size (kW)	**100**			
Stacks/Yr	100	1000	10000	50000
Required lines	1	1	1	2
Maintenance factor	0.1	0.1	0.1	0.1
Auxiliary Costs Factor	0	0	0	0
Power Consumption (kW)	10	20	20	40
Assembly line Footprint (m2)	280	280	280	560
Initial Capital	500,000	1,000,000	1,000,000	2,000,000
Initial System Cost	550,000	1,100,000	1,100,000	2,200,000
Depreciation Rate	32,666.67	65,333.33	65,333.33	130,666.67
Annual Cap Payment	81,123.48	162,246.96	162,246.96	324,493.92
Maintenance	7,374.86	14,749.72	14,749.72	29,499.45
Salvage Value	903.05	1,806.10	1,806.10	3,612.21
Energy Costs	89.69	318.90	3,189.00	31,889.95
Property Tax	2,760.00	5,520.00	5,520.00	11,040.00
Building Costs	72,925.65	72,925.65	72,925.65	145,851.31
Interest Tax Deduction	0	0	0	0
Depreciation	0	0	0	0
Machine Rate ($/hr)	**2178.28**	**1904.66**	**192.62**	**161.75**
- Capital ($/hr)	1069.61	1203.31	120.33	96.26
- Operational ($/hr)	99.53	113.01	13.45	18.42
- Building ($/hr)	1009.14	588.34	58.83	47.07

Table 4.33. Machine rates for assembly line (100kW system).

PEM fuel cell stacks have been observed to perform better in polarization tests if they first undergo stack conditioning (James et al., 2010). An example of steps of conditioning process is discussed in U.S. patent (No. 7,078,118) from UTC power systems. The conditioning process usually takes place right after stack assembly at the factory. Because the conditioning is effectively a series of controlled polarization tests, the conditioning process also serves a stack quality control purpose and no further system checkout is required.

Conditioning cost is calculated by estimating the capital cost of a programmable load bank to run the stacks up and down the polarization curve according to the power-conditioning program. The fuel cells load banks are assumed to condition three stacks simultaneously. Since the three stacks can be staggered in starting time, peak power can be considerably less than three times the individual stack rated power (James et al., 2010). Hydrogen usage is estimated based on 50% fuel cell efficiency and $5/kg hydrogen. Note that considerable power is generated which is often dumped to a resistive load dumping system; however, utilizing this generated power may be advantageous and it can be sold back to the grid.

4.6.2 Stack Assembly Cost Summary

Assembly and conditioning cost are lumped together and summarized in the following tables (Tables 4.34- 4.35) for different system sizes. These tables show cost breakdowns that cover materials, labor, capital, operational, and building costs.

Total costs for stack assembly and conditioning expressed in $/kW along y-axis and production volume (expressed by equivalent annual CCM area along x-axis) are shown in Figure 4.26. This figure (along with Tables 4.34 and 4.35) shows a decreasing cost trend with production volume and also shows that assembly and condition cost ranges between $192 per kW at low production volume (e.g. 10kW FC and 100 systems per year) and $1.25 per kW at hig production volumes. High stack assembly costs are seen at low production volume due to several factors such as high initial cost for assembly line equipment, high floor space cost compared to the production rate and partially related to the high prices for some commodities like end-plates when purchased in small volume.

System Size (kW)	10			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/kWe)	41.57	10.02	1.65	0.66
Labor ($/kWe)	4.00	1.06	0.19	0.14
Process: Capital ($/kWe)	115.61	9.74	0.83	0.34
Process: Operational ($/kWe)	21.22	17.18	13.95	12.66
Process: Building ($/kWe)	9.94	4.97	0.88	0.88
Material Scrap ($/kWe)	0.00	0.00	0.00	0.00
Total ($/kWe)	**192.33**	**42.97**	**17.51**	**14.67**

Table 4.34. Cost analysis of stack assembly for 10kW system with reformate fuel.

System Size (kW)	100			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/kWe)	10.02	1.65	0.17	0.07
Labor ($/kWe)	0.96	0.16	0.02	0.02
Process: Capital ($/kWe)	9.74	0.83	0.08	0.03
Process: Operational ($/kWe)	2.43	2.11	1.85	1.75
Process: Building ($/kWe)	0.50	0.09	0.09	0.09
Material Scrap ($/kWe)	0.00	0.00	0.00	0.00
Total ($/kWe)	**23.65**	**4.84**	**2.21**	**1.95**

Table 4.35. Cost analysis of stack assembly for 100kW system with reformate fuel.

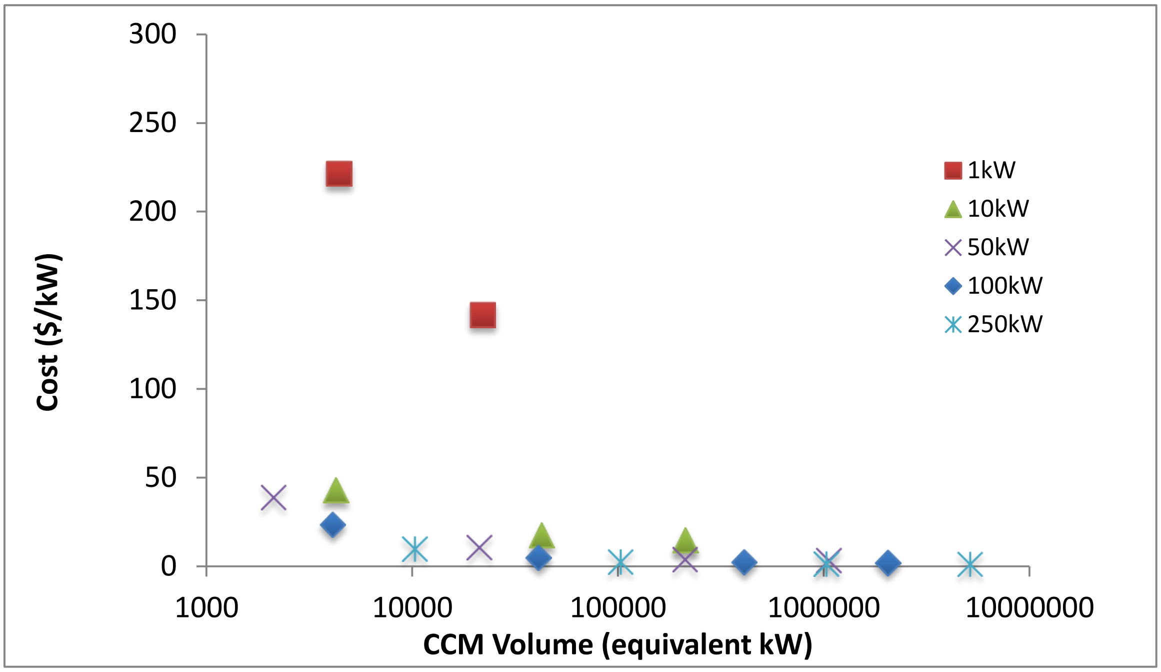
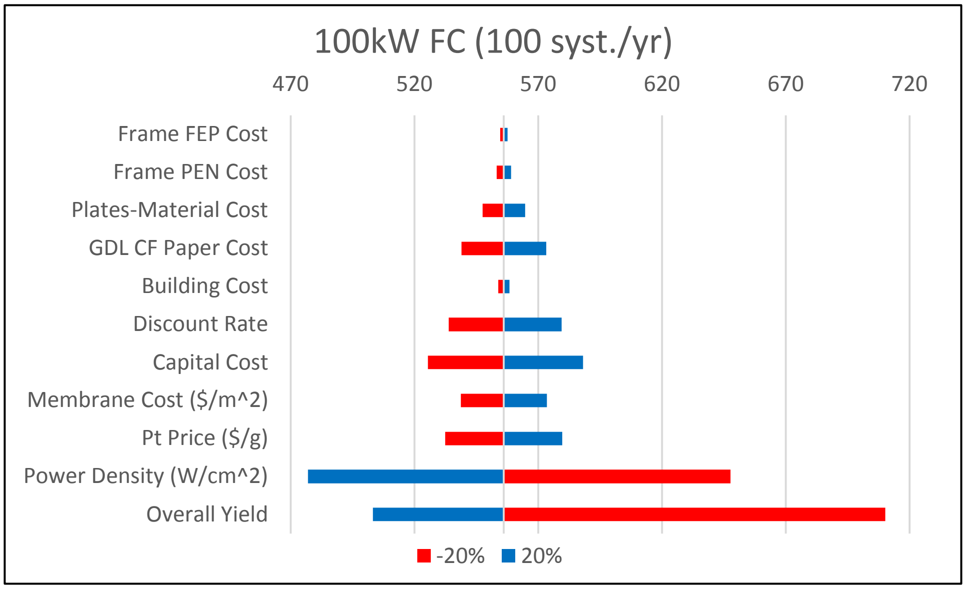


Figure 4.26. Sum of stack assembly cost and conditioning cost vs. production volume expressed in ($/kWe).

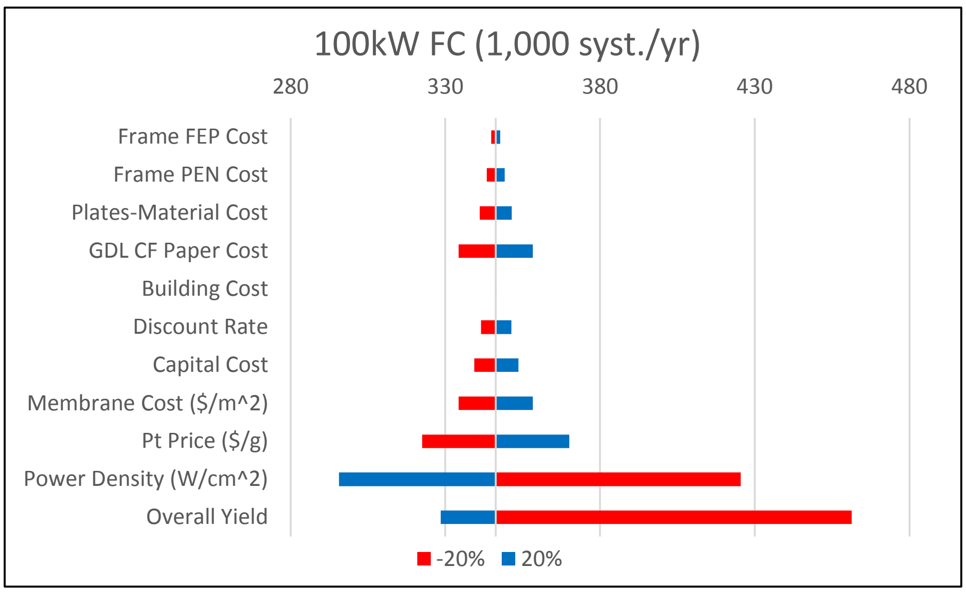
4.7 Sensitivity Analysis for Stack Cost

Sensitivity analysis for stack level was done for 100kW systems at different production volumes (as shown in Figure 4.27). The impact to the stack cost cost in $/kW is calculated for a ±-20% change in the sensitivity parameter being varied. Detalied sensitivity analysis for stack parts (CCM, GDL, plates and frame) is also included in Appendix C.

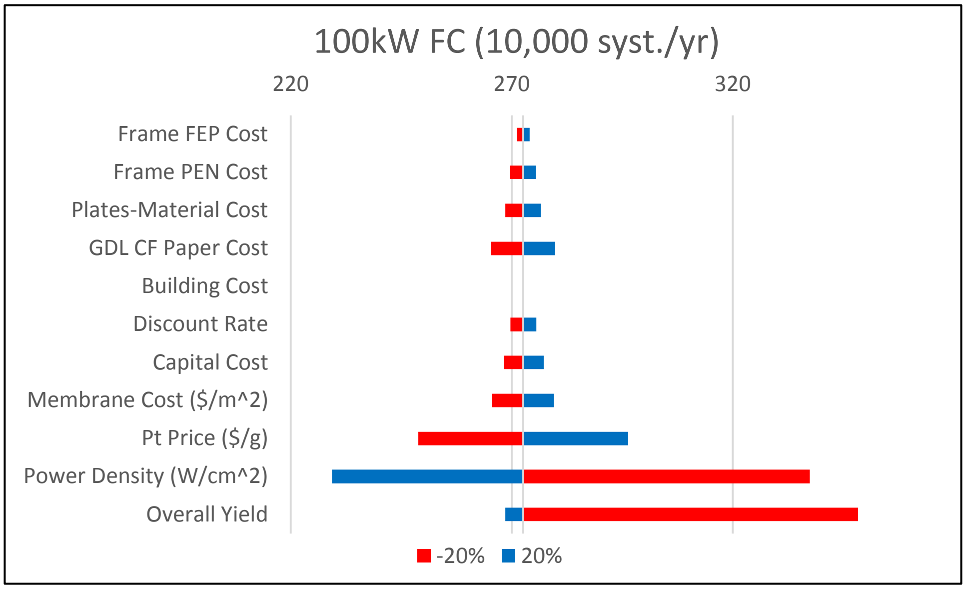
It can be seen from these plots that yield and power density are dominant cost factors at all production levels. However, Pt price and Nafion® membrane price are among other important factors which is expected for such expensive materials. The discount rate and capital cost are not large factors at high volume since material costs dominate the overall cost. Note that yield becomes less sensitive at high volume for two reasons: (1) overall yield is assumed to be very high at high volume (>95%), and (2) material costs dominate at high volume and a significant portion of material costs are recovered from rejected material.


100kW FC (100 syst./yr)
470
520
570
620
670
720
Frame FEP Cost
Frame PEN Cost
Plates-Material Cost
GDL CF Paper Cost
Building Cost
Discount Rate
Capital Cost
Membrane Cost ($/m^2)
Pt Price ($/g)
Power Density (W/cm^2)
Overall Yield
-20%
20%

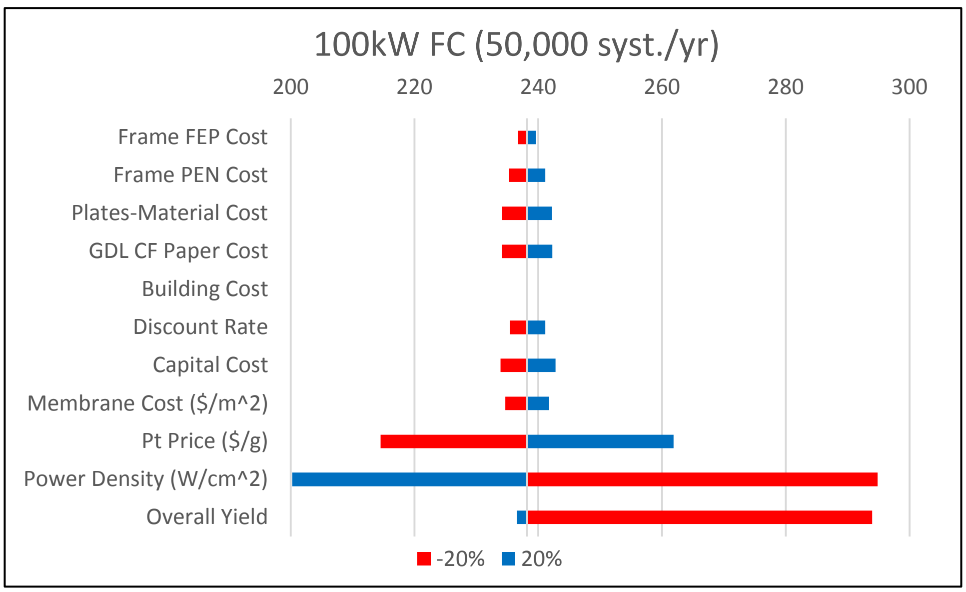
(a)


100kW FC (1,000 syst./yr)
280
330
380
430
480
Frame FEP Cost
Frame PEN Cost
Plates-Material Cost
GDL CF Paper Cost
Building Cost
Discount Rate
Capital Cost
Membrane Cost ($/m^2)
Pt Price ($/g)
Power Density (W/cm^2)
Overall Yield
-20%
20%

(b)



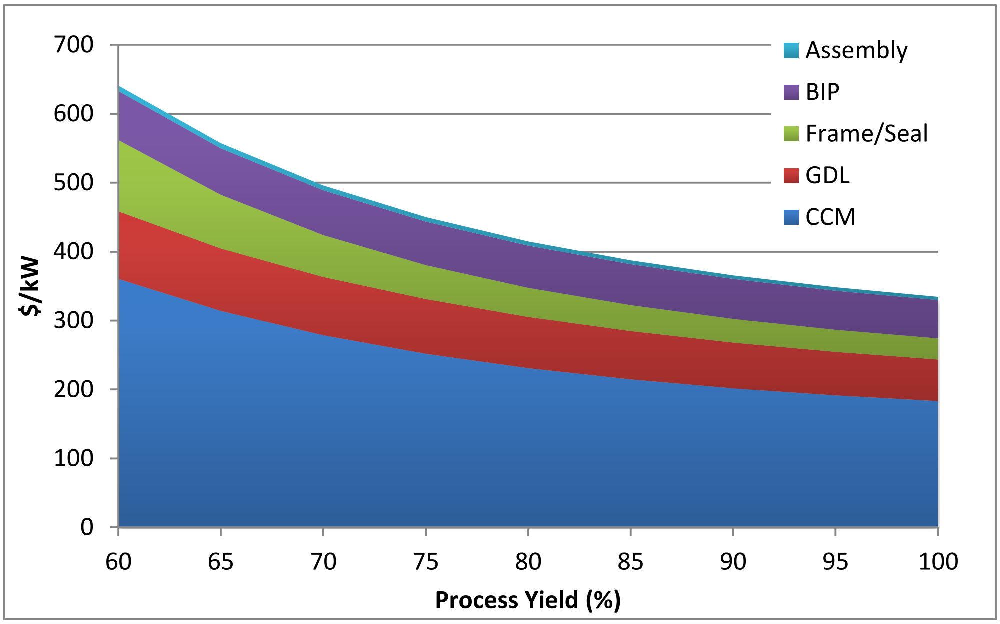
(c)



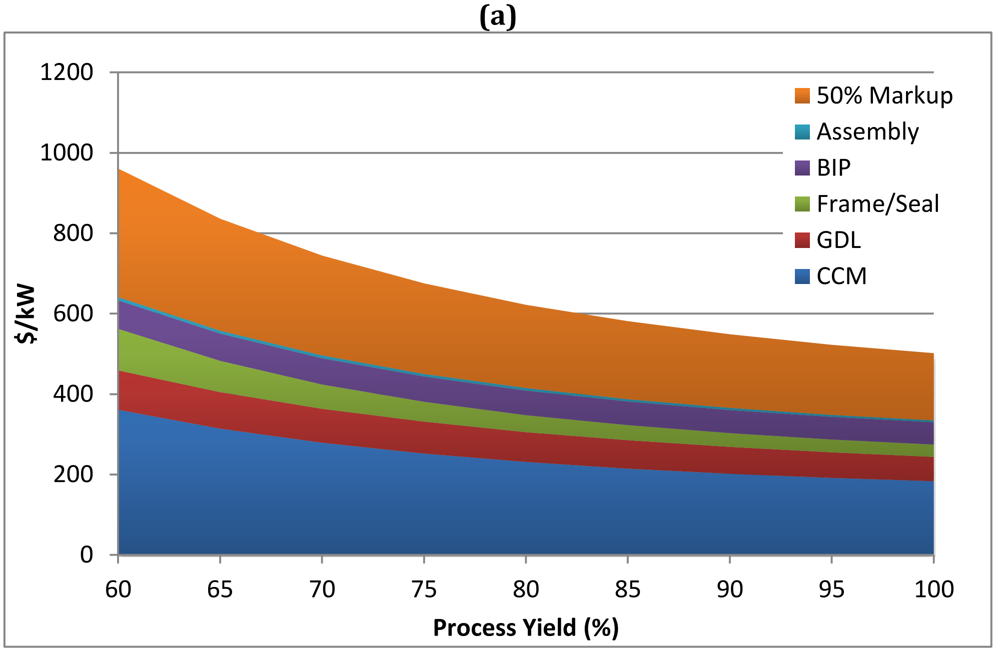
(d)

Figure 4.27. Sensitivity analyses of 100 kW system size for stack manufacturing parameters at different production volumes expressed in ($/kW): (a) 100 systems/year; (b) 1000 systems/year; (c) 10k systems/year; and (d) 50k systems/year. (Note: upper bound for yield is 100%).

From the sensitivity analysis, the total manufacturing cost is found to be most dependent on the process yield. It is thus helpful to take a closer look at the relationship between process yield and stack cost. This is shown in Figure 4.28 for 100 kW CHP reformate fuel cell system at a production volume of 1,000 systems/yr. A similar trend is also seen in other system size and annual production rate combinations.



(a)



(b)

Figure 4.28. 100kW Stack Cost vs. Yield, at Fixed Volume (1,000 units/year): (a) direct cost, and (b) direct cost with 50% corporate markup.

Figure 4.28 shows that increasing the process yield from 60% to 99.5% reduces the stack cost by almost 50%. (The assembly yield is assumed to be 99% throughout this analysis since cost would be drastically increased if all upstream value were lost at that stage in the manufacturing process).

This illustrates that in addition to increasing production volume, improved process yield also has a large effect on stack cost. Note that the yield analysis in Fig. 4.28 assumes a uniform process yield for all stack modules (CCM, GDL, frame, bipolar plates) to illustrate yield sensitivity. However, uniform yield is not assumed for the base costing case detailed earlier in this chapter and individual stack modules may have different yields, but with convergence to high yield at high manufacturing volumes.

5 Balance of Plant Costing

5.1 Overview

As described above, two different applications of LT PEM stationary fuel cell systems are examined in this report. These are:

1. Combined heat and power (CHP) applications
    - Operating on natural gas
    - System capacities of 1, 10, 50, 100, 250kW
    - System annual production volumes of 100, 1000, 100,00 and 50,000 units
    - Type of fuel cell: low temperature proton exchange membrane (LT PEM)
    - Modeled based on study of Ballard 1.1MW ClearGen® system installed in Torrance, CA

2. Backup (BU) applications
    - Operating on pure hydrogen
    - System capacities of 1, 10, 25, 50kW
    - System annual production volumes of 100, 1000, 100,00 and 50,000 units
    - Type of fuel cell: LT PEM
    - Modeled based on study of Altergy Systems back-up power systems (5-25+ kW), with production based in Folsom, CA

Balance of plant costing for these system types is discussed in this report section, noting the key differences in system design and configuration between these two rather different applications of LT PEM technology. Cost analysis studies on other types of fuel cells such as the high temperature PEM (HT-PEM) and solid oxide fuel cell (SOFC) will be considered in future work.

5.2 BOP Costing Approach

The general approach used here is a bottom-up costing analysis based on the system designs described above. . Key data and design information was gathered by examining existing fuel cell systems, consulting industry advisors, and examining various FC system specification sheets for data sources. Methods of determining the representative components found in this model range from inspection of existing stationary fuel cell systems, information gathered through surveys of industry partners, discussions and price quotes with vendors, and utilization of components used for common but similar functions in other applications. Thus, the system represented here reflects the authors' best assessment of existing or planned systems but does not necessarily capture all system components with exact fidelity to existing physical systems, nor does there exist a physical system that is exactly the same as that described here.

The BOP is divided into six subsystems or subareas listed below:

1. Fuel Subsystem
2. Air Subsystem
3. Coolant Subsystem and Humidification Subsystems
4. Power Subsystem
5. Controls & Meters Subsystem
6. Miscellaneous Subsystem

For the CHP systems with reformate fuel, fuel processor costs were adopted from earlier work by Strategic Analysis (James et al., 2012). All other subsystem components were estimated using bottom-up costing analysis and vendor quotes.

We did not consider the case of BOP components built in-house (i.e., "make" versus "buy") because the components are largely commodity parts (e.g. tanks, motors, cabinets, variable frequency drives, tubing, piping, inverters, valves, heat exchangers, switches). Our research team also deemed it unlikely that a FC manufacturer would embark upon a program of producing BOP commodity parts in-house, with infrequent exceptions still being investigated. . Thus, the BOP is largely assumed to be comprised of purchased components that are either assembled or integrated by a fuel cell system manufacturer. In some cases, customized designs are required for FC system applications since CHP systems are not being produced in high volume, however they are generally still assumed to be comprised of commodity products that could be produced in larger volume in the future, and perhaps as more integrated sub-assemblies. In such cases, it is possible that a FC manufacturer would work closely with a contract manufacturer or parts vendor to prototype and develop such subassemblies. This type of parts integration and subassembly design were not explicitly considered in this work, but may represent further cost-reduction opportunities.

Scaling Basis and Rationale

A majority of the analysis in the BOP for the CHP system is based on Ballard's 1.1MW Clear Gen™ System, located at a Toyota facility in Torrance, CA. The Torrance system is divided into two 550-kW modules. To scale down to the 250kW system, most components were roughly downsized by half of what is present in each 550-kW section (assuming configuration and specs provided). For example, the size of the humidifier tank in the Torrance system is approximately 300 gallons; for the 250kW system, a 150 gallon tank was quoted for the BOP, 75 gallon for the 100kW, 50 gallon sized for the 50kW, 10 gallon tank for the10kW, and 1 gallon for the 1kW etc. This scaling scheme was carried out similarly for items such as pumps, motors, and heat exchangers. If exact capacities were not available, the component would be "scaled-up" to provide a robust system design and to give a more conservative costing estimate.

For other components such as piping, safety system, enclosures, and labor cost, the BOP was based upon literature available from Strategic Analysis, Directed Technology, and Altergy Systems on stationary and transportation fuel cell-related systems. Items in the Power and Controls & Metering Subsystems were based largely on inspections at the Richmond Hydrogen Fueling Station in Richmond, CA, which contains similar controls and systems.

Key Assumptions

The following assumptions were made in order to approach and complete the BOP cost analysis:

- Scaling of components or BOP was based on the Ballard 1.1MW ClearGen®™ System- components were mostly "scaled up" in size, if no exact model match was available with suppliers, or if the item had no direct scaling.
- For CHP operation, the waste heat from the FCS is utilized for hot water or space heating (by use of either a liquid-liquid heat exchanger or liquid-gas exchanger).
- Grid-dependent operation was assumed (no battery) for CHP application.
- In the CHP applications, there is an afterburner placed after the stack to recover heat from excess fuel and oxidant not consumed in the fuel cell stack. The heat can be directed back to the reformer for startup (Colella 2003) or otherwise used for system performance improvement.
- Residential or small commercial applications were assumed for smaller power CHP systems while industrial/commercial applications were assumed for larger power CHP systems.

This assumption provided room for system simplification by reducing components that were not crucial for small residential fuel cell systems.

- For volume quotes that did not come directly from vendors sales representatives, a 20% price scaling for a 10x factor increase in volume was assumed. This volume discount approach is similar to that applied to purchase stack components (e.g., carbon fiber paper, and Nafion® membrane).
- H_2 purifiers were assumed to be optional for small capacity CHP applications with direct H_2 fuel, with the assumption that the fuel already meets system purity requirements.
- BOP cost excludes freight (shipping) cost.

5.3 System Terminology

The fuel cell system (FCS) consists primarily of the fuel cell stack and the balance of plant (BOP) components. The BOP includes items such as valves, compressors, pumps, wiring, piping, meters, controls etc. that are associated with the complete operation of the fuel cell system.

Six major areas make up the BOP and are listed and shown in the schematic below:

1. Fuel Subsystem
2. Air Subsystem
3. Coolant and Humidification Subsystems
4. Power Subsystem
5. Controls & Meters Subsystem
6. Miscellaneous Subsystem

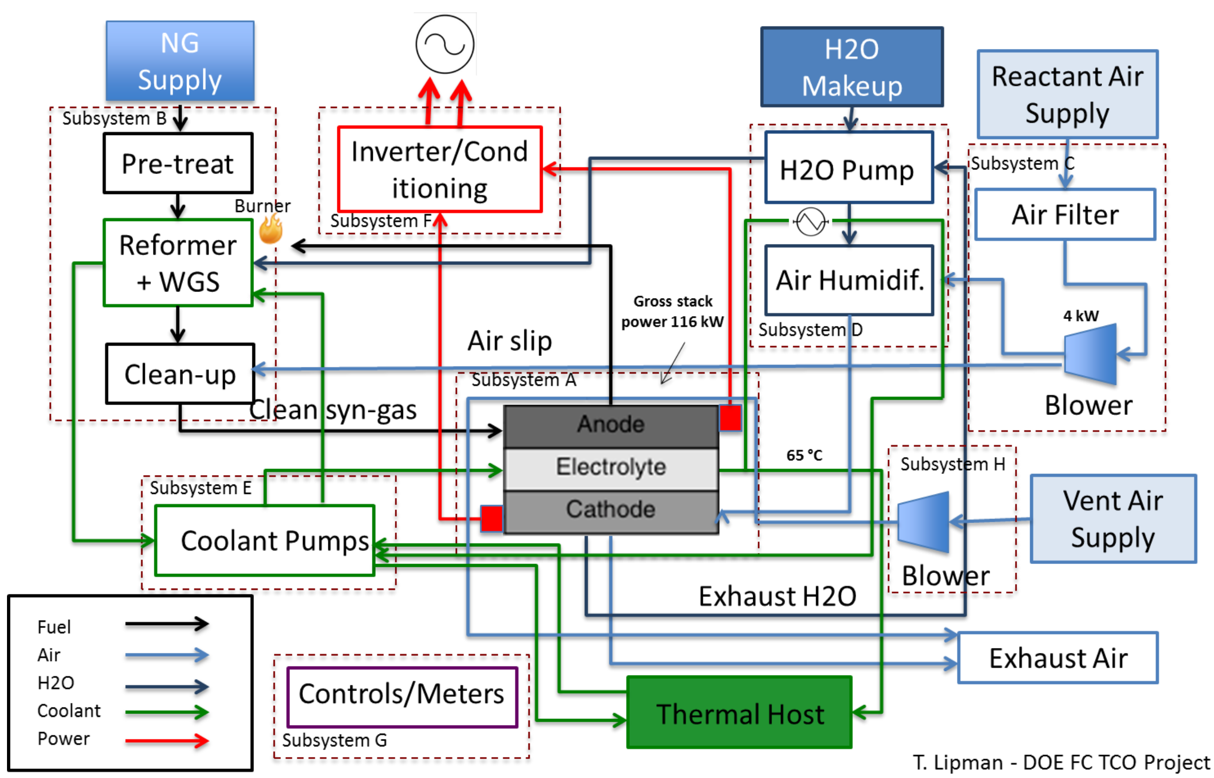


Figure 5.1. Schematic of CHP system with reformate fuel.

Each subsystem is described below:

+ Fuel Processing Subsystem
  The fuel processing subsystem consists of a fuel processor for producing hydrogen fuel from natural gas. A schematic of the FCS with reformer subsystem is shown in Figure 5.1. The fuel processing subsystem is comprised of components associated with the operation of the fuel reformer, which includes parts such as sensors, controls, filters, pumps, and valves.

+ Air Subsystem
  The air subsystem consists of components associated with oxidant delivery to the fuel cell stack. Major components in this subsystem are storage tanks, compressor, motor, piping, and manifolds.

+ Coolant & Humidification Subsystem
  The coolant subsystem consists of components associated with water management in the FCS, including humidification of membranes. These include: tank, pump motor, piping, external cooling motor, and heat exchanger.

+ Power Subsystem
  The power subsystem contains components required for powering the system and conditioning the output power. The system includes: inverter, transistor, transformer, power supply, relays, switches, fuses, resistors, Human Machine Interface (HMI), amplifiers, and cables.

+ Controls & Meters Subsystem
  This controls and meters subsystem contains system controls-related components for system operation and equipment monitoring. This subsystem includes items such as the variable frequency drive (VFD), sensors, meters, and virtual private network (VPN) system.

+ Miscellaneous Subsystem
  The miscellaneous subsystem comprises external items outside of the stack that provides support, structure, and protection for the FCS. These items include: tubing, enclosure, fasteners, fire/safety panels, and labor.

5.4 Balance of Plant Results

CHP System with Reformate fuel

In the CHP system with reformate fuel, the stationary fuel reactor display in the figure below is designed to carry out external natural gas steam reforming processes, which include fuel/air preheating, steam reforming, water gas shift (WGS) reaction, and preferential oxidation (PROX). In this report, the fuel processor costs were adopted from SA's previous work on fuel processor for their 25kW system. The results from their DFMA analysis were scaled to higher power levels and adopted as a representation of cost for the Fuel Reformer Subsystem.

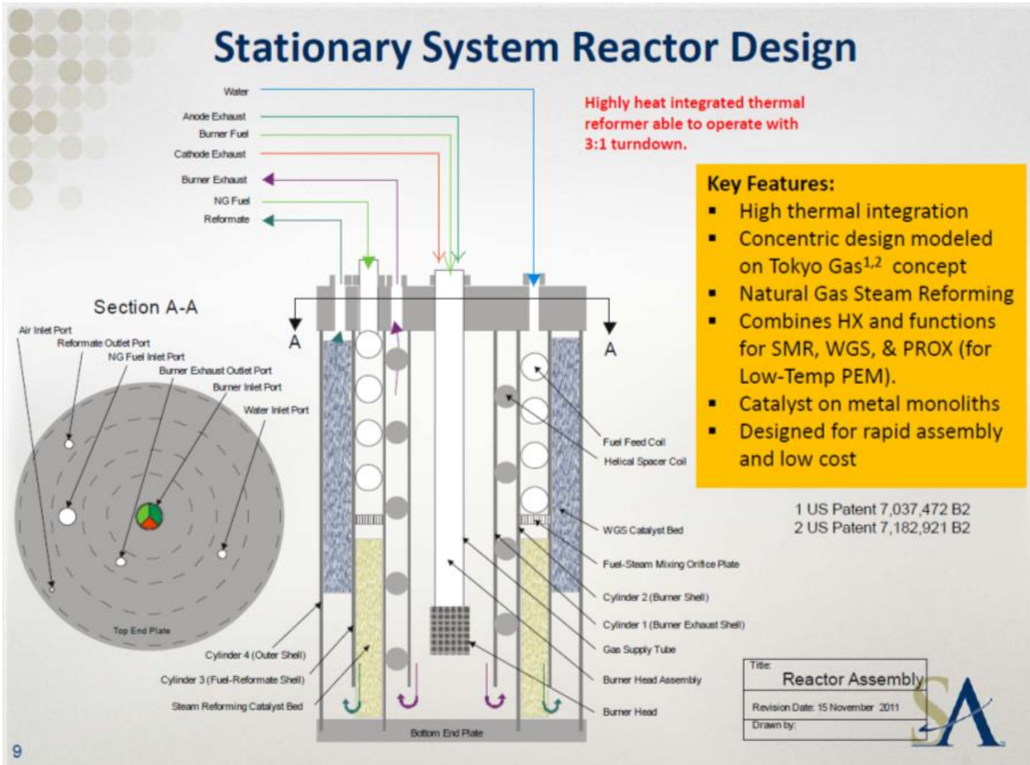


Figure 5.2. Reactor design for stationary fuel cell system (James et al., 2010).

Table 5.1 displays Reformer Subsystem projection costs based on SA's previous DFMA work on fuel processors (James et al., 2012). Costs estimates were obtained by extrapolating the 25kW to 100kW costs versus power curves to 250kW, with the assumption that a 25kW system can be extended to 50kW and that five 50kW reformers could support a 250kW system (4x25kW reformers were used for 100kW systems in an earlier study).

	Total Reactor, Reformer BOP, and Reformer Subsystem Assembly Cost per kWnet				Refined Linear Projection
	1 kW/sys	**5 kW/sys**	**25 kW/sys**	**100 kW/sys**	**250 kW/sys**
100 sys/yr	$4,239	$1,321	$329	$262	$225
1,000 sys/yr	$3,263	$1,077	$278	$231	$203
10,000 sys/yr	$2,770	$928	$250	$215	$194
50,000 sys/yr	$2,547	$854	$239	$207	$188

Table 5.1. Estimated fuel processor costs per kW based on earlier SA DFMA costing for 50kW systems.

Based on our initial cost estimates on the Fuel Reformer Subsystem, it was observed that SA's cost projections for fuel processors are quite aggressive. In addition, SA's reactor design features natural gas steam reforming combining heat exchange with steam methane reforming and WGS. One key limitation in this design could be excessive pressure drop in the reactor. An alternative design with increased linear flow and vessels placement in series may be preferred for enhanced reliability. A more detailed analysis on optimal fuel processor design, scaling and modularity should be considered in future work.

Table 5.2 displays the component breakdown of BOP and subsystem costs for the 10kW and 100kW CHP system with reformate fuel at production volume of 1000 systems per year. For the 100kW CHP system, the heat exchanger and external cooling motor dominates the coolant subsystem, accounting for approximately two thirds of the subsystem cost. The cost of the power subsystem is dominated by the power inverter, which accounts for approximately 68% of the subsystem cost. In the controls subsystem, costs are driven by the complex sensor heads systems use for hydrogen leak detection. The air subsystem contains fairly balanced costs among each component.

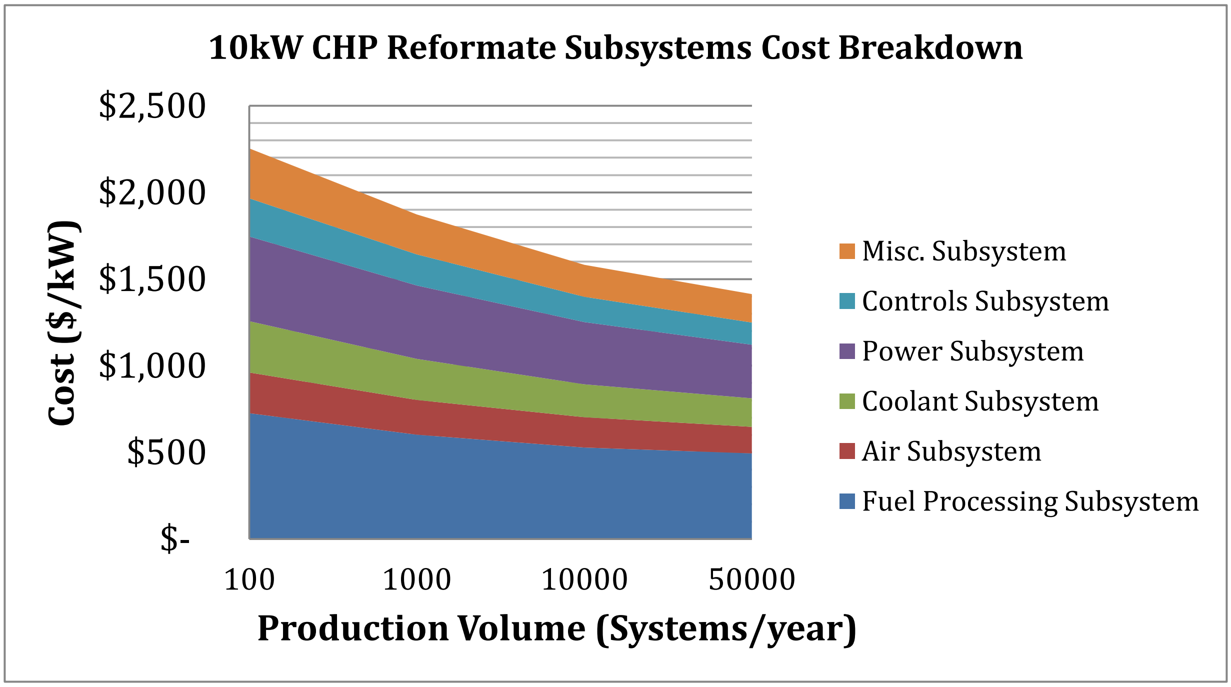
CHP System with Reformate Fuel Component Breakdown (for 1000 systems/year)	**10kW**	**100kW**
	$/kW	
Fuel Processing Subsystem		
	602	231
Air Subsystem		
Air Humidfier Tank Humidification Pump Humidification Pump Motor Air Pump Compressor Air Pump Motor Radiator Manifolds Air Piping	201	57
Coolant Subsystem		
Coolant Tank Coolant Pump Motor Coolant Piping External Cooling Motor Heat Exchangers	237	122
Subsytem 4: Power System		
Power Inverter Braking Transistors Transformer Power Supply Relays Switches Fuses HMI Bleed Resistor	424	253

Ethernet Switch Power Cables (2W and 4W) Voltage Transducer		
Subsystem 5: Controls/Meters		
Variable Frequency Drive Thermosets CPU Flow Sensors Pressure Transducer Temperature Sensors Hydrogen Sensors Sensor Heads VPN/ Gateway/Data Storage Computer Coriolis Flow Meter (optional)	179	128
Subsystem 6: Misc. Components		
Tubing Wiring Enclosure Fasteners Fire Detection Panel Safety System (Leak Detection) Iso Container (Customized) Labor Cost	231	63
Total $/kW	**1873**	**855**

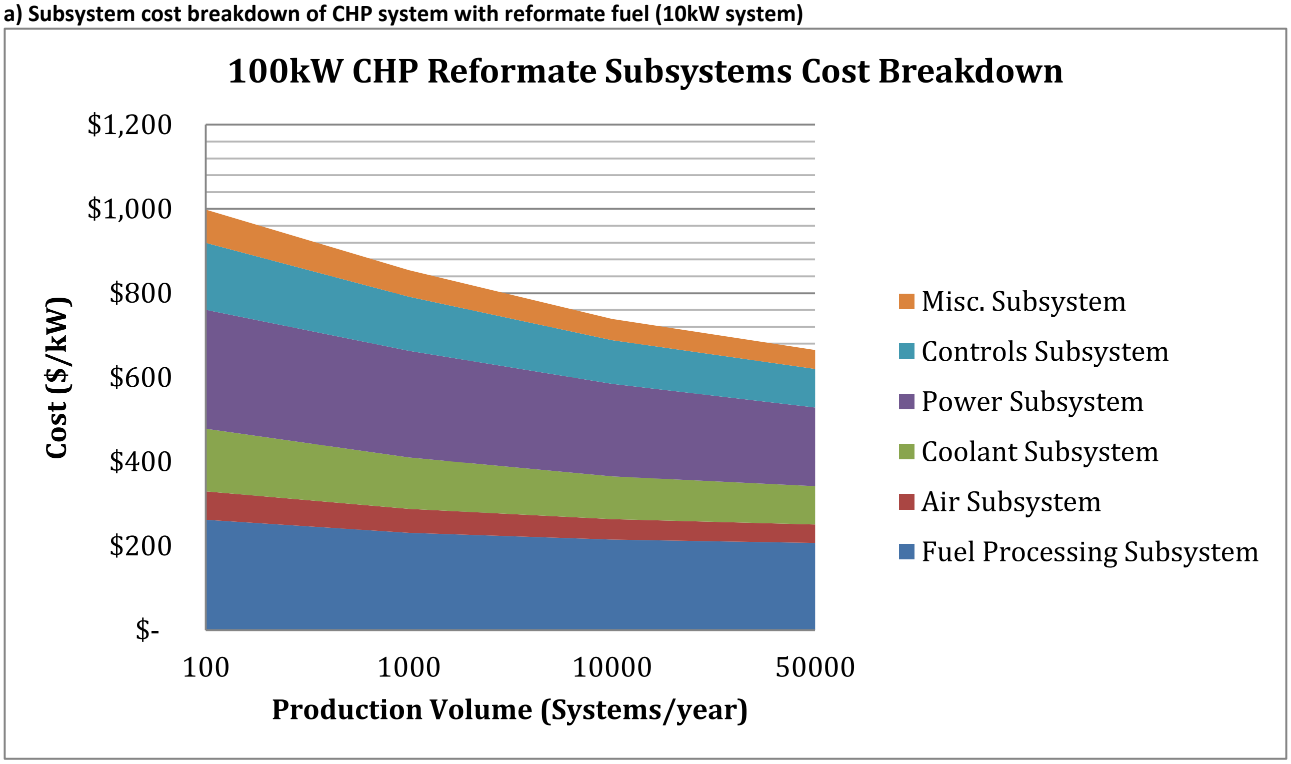
Table 5.2. Component and subsystem cost of CHP system with reformate fuel (10kW, 100kW) subsystem at an annual production volume of 1000 systems per year.

Figure 5.3a-b displays the subsystem breakdown for the 10kW and 100kW CHP system with reformate fuels for various production units. The fuel processing subsystem is the largest component of system cost at smaller system size (~20% of BOP costs) while the power subsystem and fuel processing subsystem comprise about 60% of total BOP costs in the larger system sizes (50, 100, 250kW).

Figure 5.4 displays the BOP cost as a function of manufacturing volume for the CHP system with reformate fuels. The cost per unit of electric output decreases with increasing manufacturing volume and increasing system size. Increasing capacity appears to have a greater effect on cost reduction in comparison to increasing manufacturing volume. Table 5.3 summarizes the volume cost results for the CHP system with reformate fuel. The data shows that cost reduction is seen to be generally less than 20% per ten-fold increase in annual volume. Vendor quotes were utilized for BOP component as a function of volume and were often less than 20% per decade increase in annual volume.



a) Subsystem cost breakdown of CHP system with reformate fuel (10kW system)



b) Subsystem cost breakdown of CHP system with reformate fuel (100kW system)

Figure 5.3. Subsystem cost breakdown of CHP system with reformate fuel for: a) 10kW system; b)100kW system.

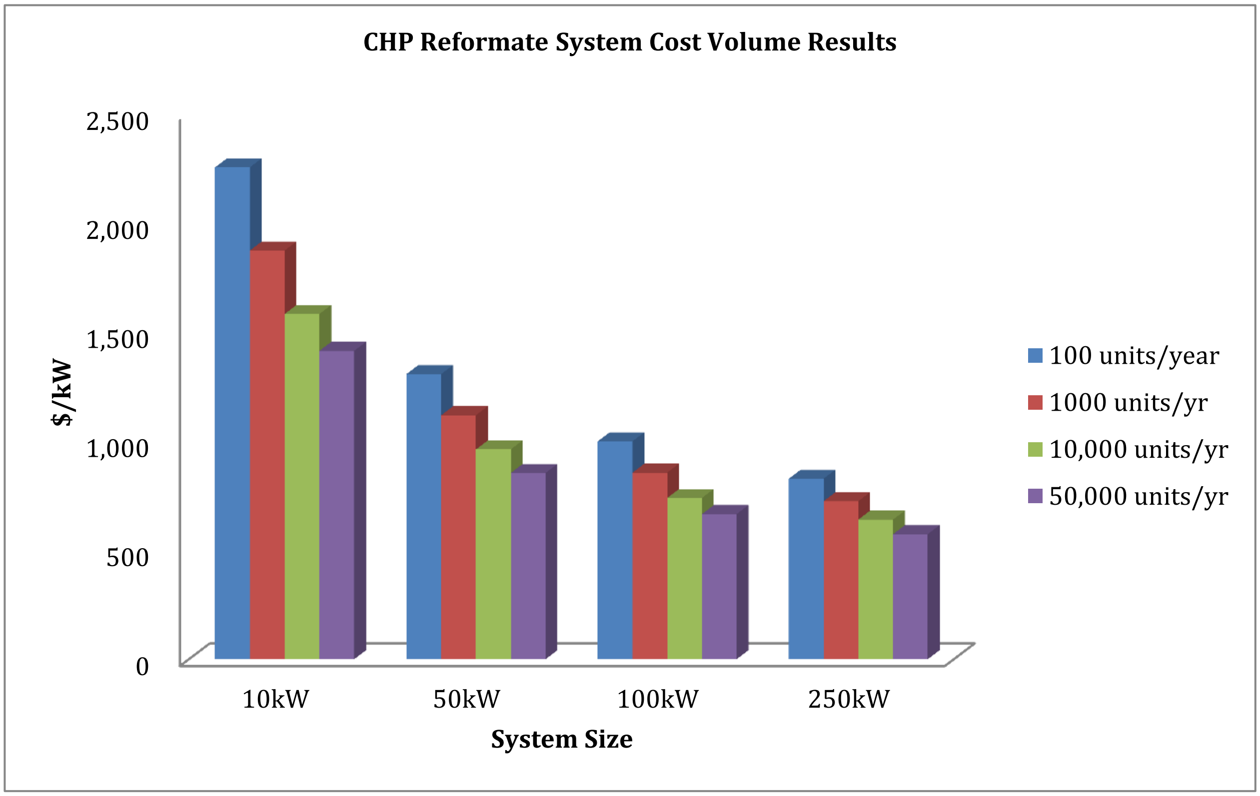


Figure 5.4. BOP cost volume results for CHP system with reformate fuel.

CHP Reformate ($/kW)	1kW	10kW	50kW	100kW	250kW
100 units/year	11,871	2,254	1,307	998	827
1,000 units/year	9,489	1,873	1,118	855	724
10,000 units/year	8,079	1,582	962	739	640
50,000 units/year	7,125	1,413	853	665	573

Table 5.3. Summary of BOP cost for CHP system with reformate fuel.

Backup System with Direct Hydrogen Fuel

Figure 5.5 displays the subsystem cost breakdown for the 10kW backup system as a function of manufacturing volume. Unlike the CHP systems, the Fuel Subsystem dominated the BOP costs at all system capacities. The major cost drivers in the Fuel Subsystem are the fuel blower and manifold fitting system. One distinct difference between the CHP and backup FCS is the assumption of air cooling in the backup system, thus eliminating the need for a coolant subsystem.

Figure 5.6 displays the BOP volume cost results as a function of manufacturing volume. As seen in the figure, the cost per unit of electric output decreases with increasing manufacturing volume and increasing system size. In general, increasing capacity has a greater effect on cost reduction in comparison to increasing manufacturing volume. Table 5.4 summarizes this data.

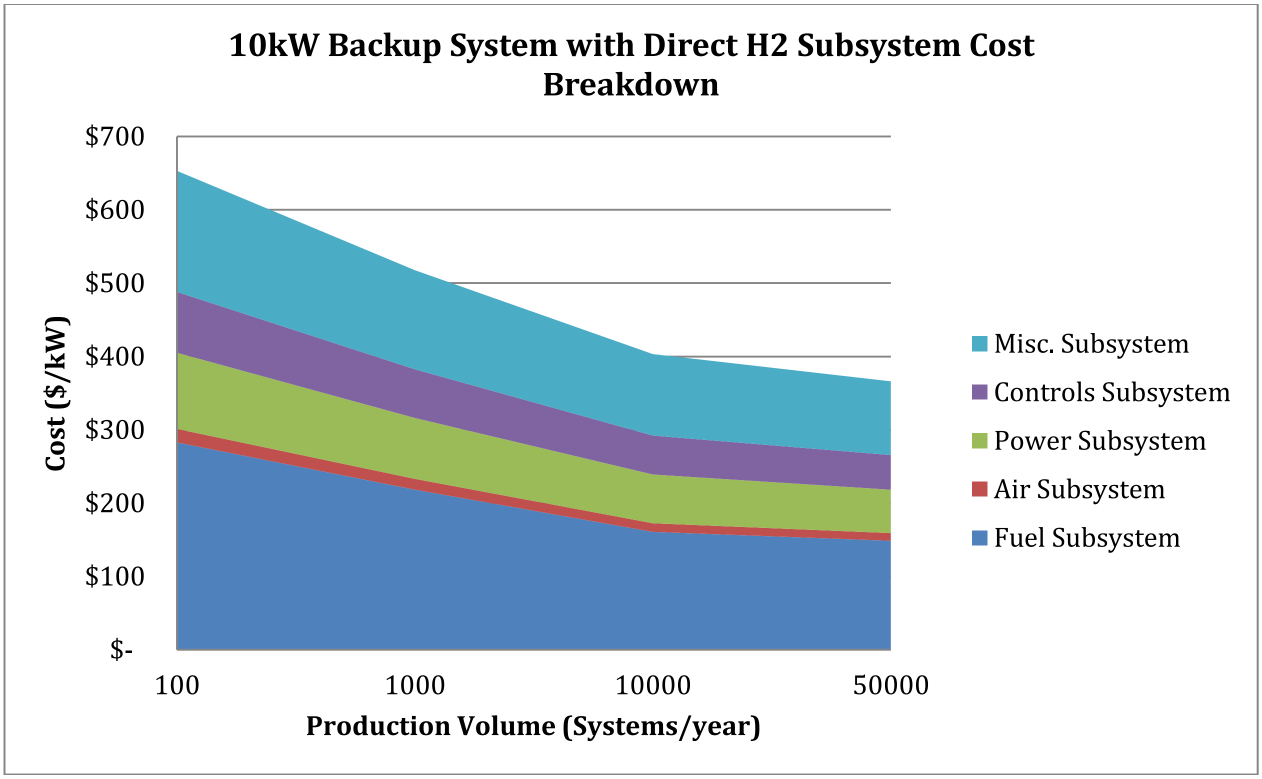


Figure 5.5. Subsystem cost breakdown of backup system with direct hydrogen (10kW system).

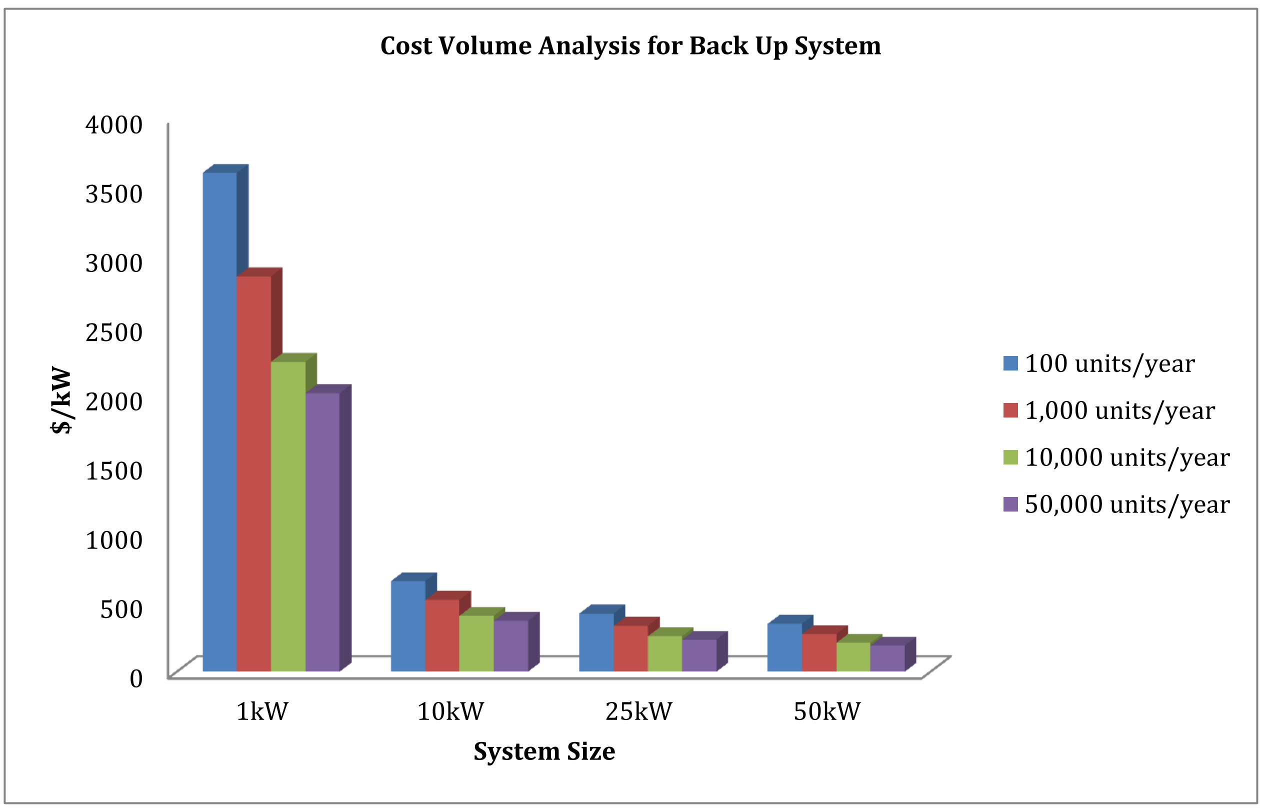


Figure 5.6. Cost volume results for backup systems with direct hydrogen.

Backup System with Direct H_2 (\$/kW)	1kW	10kW	25kW	50kW
100 units/year	3597	653	420	345
1,000 units/year	2852	518	331	271
10,000 units/year	2235	403	255	208
50,000 units/year	2008	366	231	188

Table 5.4. Summary of BOP cost for backup system with direct hydrogen fuel.

5.5 Balance of Plant Conclusions

This part of the study presents a detailed balance of plant cost analysis for stationary fuel cell systems including the cost dependencies of increasing system size and increasing manufacturing volumes. The balance of plant encompasses components and structures outside of the fuel cell stack associated with the operation of the complete fuel cell system.

Based on our analysis, it was observed that system cost in per-kW terms decreases with both increasing system size and manufacturing volume. While both of these factors affect cost, increasing system capacity is seen to have a greater impact on driving cost per kilowatt down.

For the CHP system with reformate fuel, the Power Subsystem represents the biggest subsystem cost for the bigger capacity systems, dominating approximately 35-40% percent of the total BOP. In particular, the power inverter is a dominant cost driver, representing up to 80% percent of the cost in the Power Subsystem. The second biggest subsystem is the Fuel Processing Subsystem. The Fuel Processing Subsystem represents up to 33 percent of BOP cost for smaller capacity systems. In general, BOP components that are cost drivers for direct-hydrogen CHP systems were power inverter, heat exchangers, flow sensors, hydrogen sensors, and the hydrogen purifier for sulfur and CO contamination.

The BOP analysis reported here presents greater detail in component requirements than typically reported in previous fuel cell system cost studies. As our study indicated, the BOP can actually be the dominant cost driver in FCS assuming that the fuel cell stack adopts more fully automated processing with much higher production volumes than today. Most research to date has focused on cost reduction in the stack and may have underestimated the cost and complexity of the BOP components. Our studies indicate that there is a need to assess BOP in greater detail. With increased manufacturing volume of fuel cell systems, there will be greater potential for fuel cell companies to standardize an increasing the number of BOP parts for specific fuel cell systems. Commoditization of BOP components for FCS may in turn significantly impact system cost and the presence of emerging fuel cell systems in the market.

5.6 Key Cost Reduction Opportunities

Based on our analysis, further reductions in the fuel cell system BOP components costs can be achieved with greater standardization for components such as inverter, purifiers, manifolds etc. According to input from Ballard Power Systems, the development of standardized component such as power inverters for FCS with suppliers can reduce costs by as much as 50 percent (McCain, 2013). Key cost reduction opportunities include:

- Consolidation of common parts to create an integrated modular package (e.g. valves packages), tailored for specific fuel cell systems. While market demand for integrated fuel cell system parts have not reached a point where suppliers and manufacturers are willing to develop specialized products for the fuel cell industry, the potential for cost reduction can increase significantly with increasing FCS production in the market.
- The BOP is an overlooked area of research in FCS. While a majority of research has been focused on cost reduction of the fuel cell stack, the BOP represents a large amount of system cost. Furthermore, our analysis shows that BOP does not scale as well as the fuel cell stack.
- The fuel reforming subsystem makes a significant cost contribution to the BOP. Alternative designs that can enhance performance and heat transfer characteristics, along with a full DFMA costing analysis, may help drive down cost of the fuel reforming subsystem.

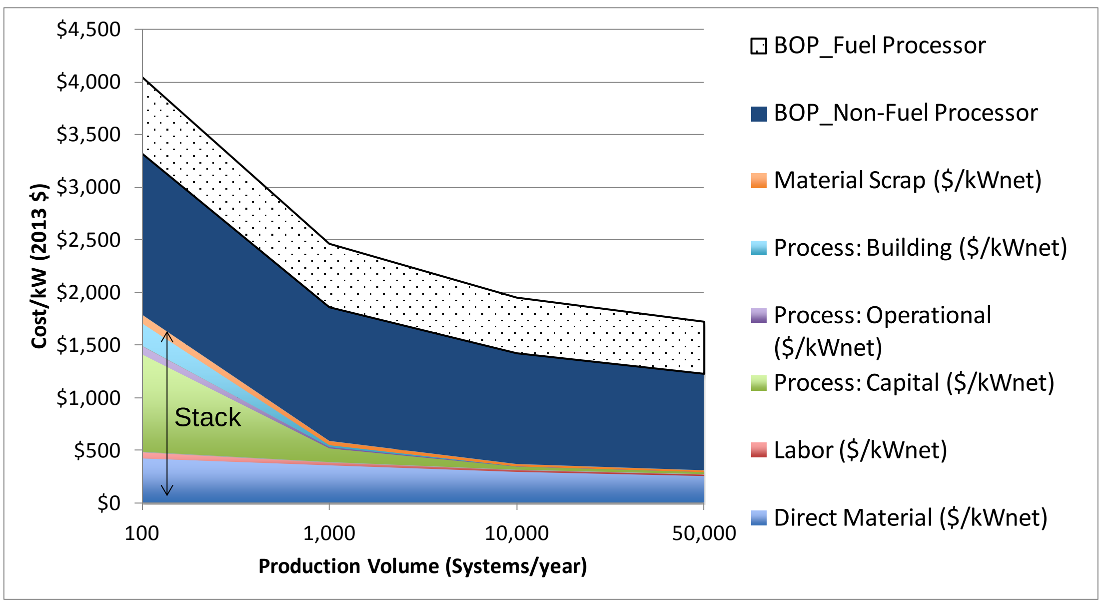
6 Fuel Cell System Direct Manufacturing Costs and Installed Cost Results

Stack costing from Chapter 4 and balance of plant costing from Chapter 5 are integrated in this chapter to provide a roll up of fuel cell stack direct manufacturing costs, system costs including stack costs and balance of plant/fuel processor costs, and installed costs for CHP systems with reformate fuel and backup power systems.

6.1 CHP system with reformate fuel

Detailed system costing results are shown below for CHP systems with reformate fuel at 10 and 100 kWe system sizes and backup power systems with metal bipolar plates at 10 and 50 kWe system sizes. These represent a synthesis of system designs, functional specifications, DFMA costing analysis for FC stack components, and the BOP costing discussion from the preceding chapters. Three sets of plots are shown: (1) overall system costs per kWe as function of production volume (100, 1000, 10000, and 50000 systems per year), (2) a breakout of BOP costs versus FC stack costs as a percentage of overall costs; and (3) a disaggregation of stack components by relative percentage of overall stack cost. Additional cost plots can be found in Appendix D. As noted above, these costs represent direct manufacturing (or purchased parts for BOP) and do not include non-product costs such as profit margin, G&A, sales and marketing, warranty costs, etc. Typical markups are expected to about 40% to 60% for the final "factory gate" price, not including shipping to the customer location.

(a)10 kWe



(b) 100 kWe

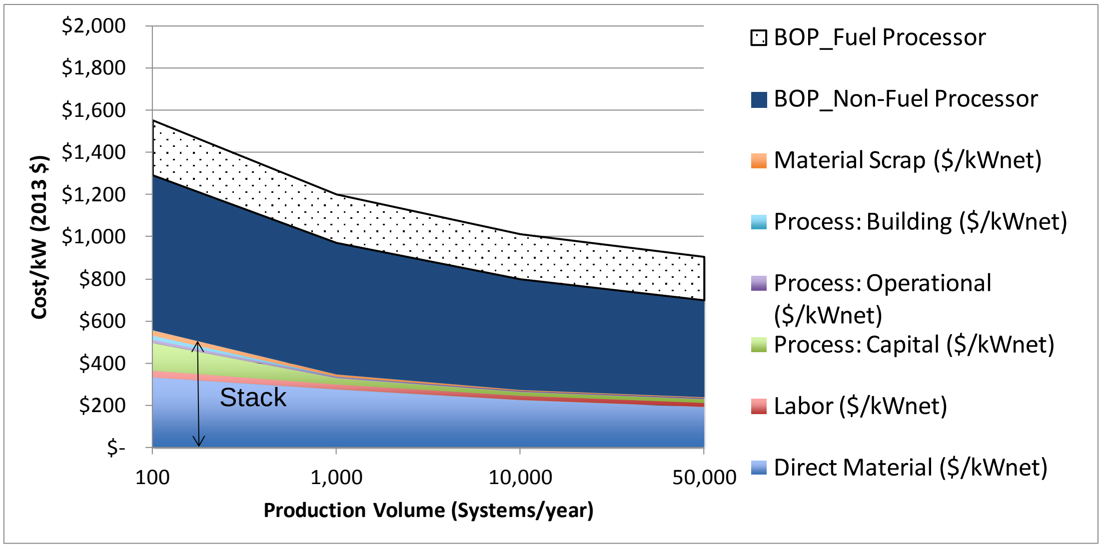


Figure 6.1. Overall System cost results for CHP systems with reformate fuel for (a) 10kWe and (b) 100kWe system sizes.

System Size (kWe)	10			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Fuel Cell Stack Direct Material ($/kWe$_{net}$)	$ 426.63	$ 360.23	$ 297.10	$ 257.14
Fuel Cell Stack Labor ($/kWe$_{net}$)	$ 57.45	$ 25.38	$ 15.43	$ 13.21
Fuel Cell Stack Process: Capital ($/kWe$_{net}$)	$ 932.01	$ 130.35	$ 28.58	$ 18.66
Fuel Cell Stack Process: Operational ($/kWe$_{net}$)	$ 76.43	$ 14.87	$ 6.10	$ 5.03
Fuel Cell Stack Process: Building ($/kWe$_{net}$)	$ 217.07	$ 20.67	$ 2.44	$ 1.13
Fuel Cell Stack Material Scrap ($/kWe$_{net}$)	$ 80.60	$ 38.11	$ 20.47	$ 15.41
Fuel Cell Stack Cost	$ 1,790	$ 590	$ 370	$ 311
BOP_Non-Fuel Processor	$ 1,529	$ 1,271	$ 1,055	$ 919
BOP_Fuel Processor	$ 725	$ 602	$ 527	$ 494
Total ($/kWe$_{net}$)	$ 4,044	$ 2,462	$ 1,952	$ 1,724

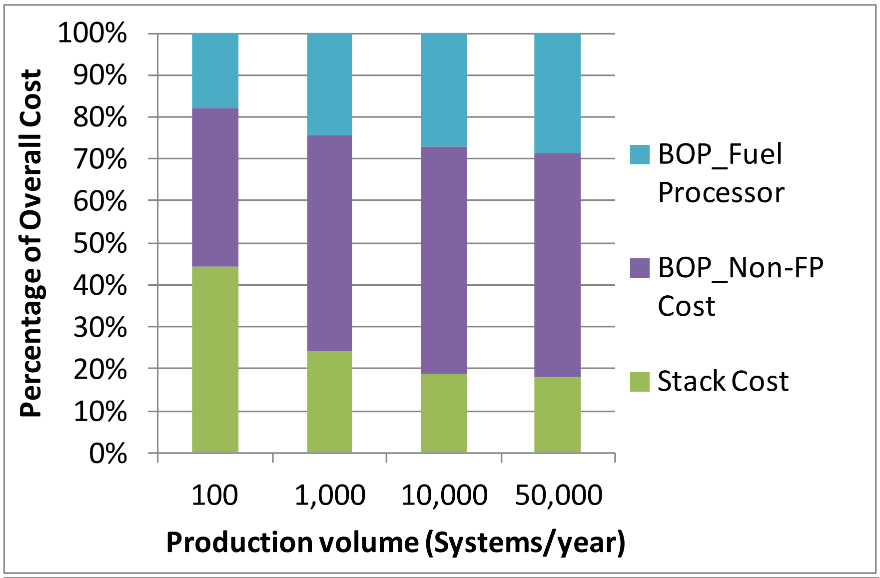
(a)

System Size (kWe)	100			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Fuel Cell Stack Direct Material ($/kWe$_{net}$)	$ 333.31	$ 275.34	$ 223.85	$ 190.30
Fuel Cell Stack Labor ($/kWe$_{net}$)	$ 32.52	$ 25.06	$ 22.65	$ 22.39
Fuel Cell Stack Process: Capital ($/kWe$_{net}$)	$ 130.35	$ 28.58	$ 17.24	$ 16.94
Fuel Cell Stack Process: Operational ($/kWe$_{net}$)	$ 14.60	$ 5.93	$ 4.82	$ 5.25
Fuel Cell Stack Process: Building ($/kWe$_{net}$)	$ 20.67	$ 2.44	$ 0.77	$ 0.68
Fuel Cell Stack Material Scrap ($/kWe$_{net}$)	$ 24.67	$ 8.92	$ 3.28	$ 2.65
Fuel Cell Stack Cost	$ 556	$ 346	$ 273	$ 238
BOP_Non-Fuel Processor	$ 736	$ 624	$ 524	$ 458
BOP_Fuel Processor	$ 262	$ 231	$ 215	$ 207
Total ($/kWe$_{net}$)	$ 1,555	$ 1,201	$ 1,011	$ 903

(b)

Table 6.1. System Cost breakdown for CHP with reformate fuel at following System Sizes: (a) 10kWe, and (b) 100 kWe. Additional cost tables can be found in Appendix D.

(a) 10 kWe



(b) 100kWe

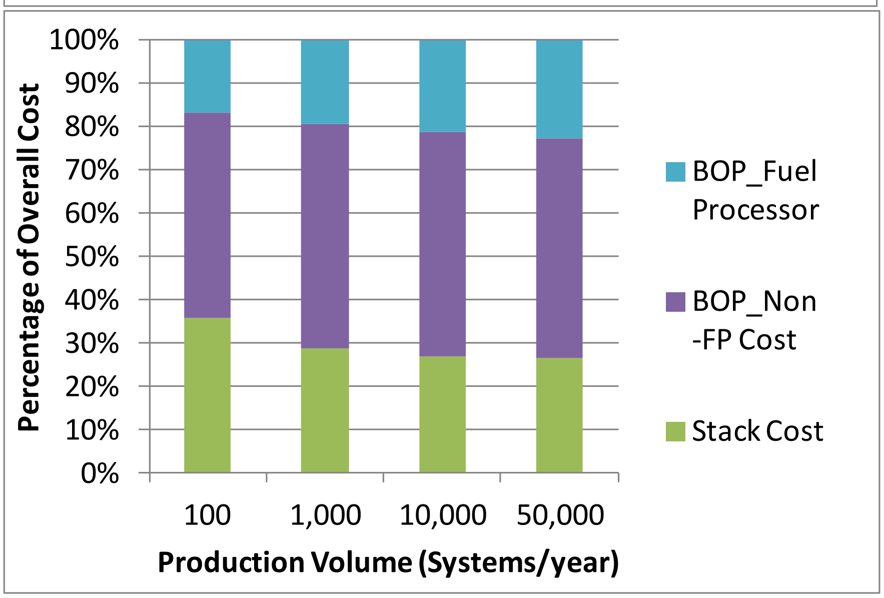
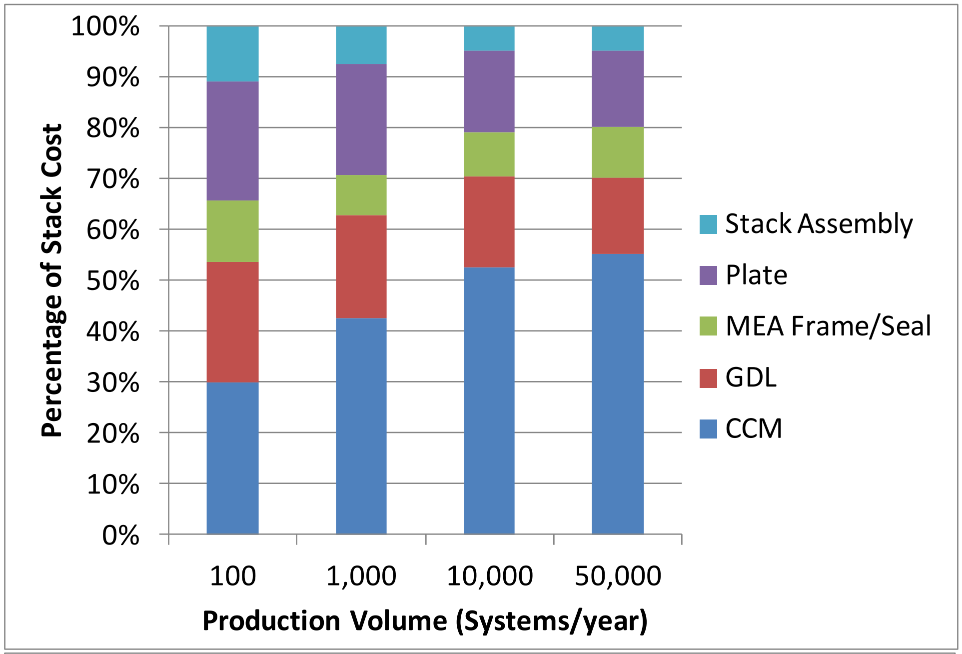


Figure 6.2. Percentage of overall system costs for balance of plant, fuel processor and fuel stack costs for 10 kWe and 100 kWe CHP systems with reformate fuel.

(a) 10kWe



(b) 100kWe

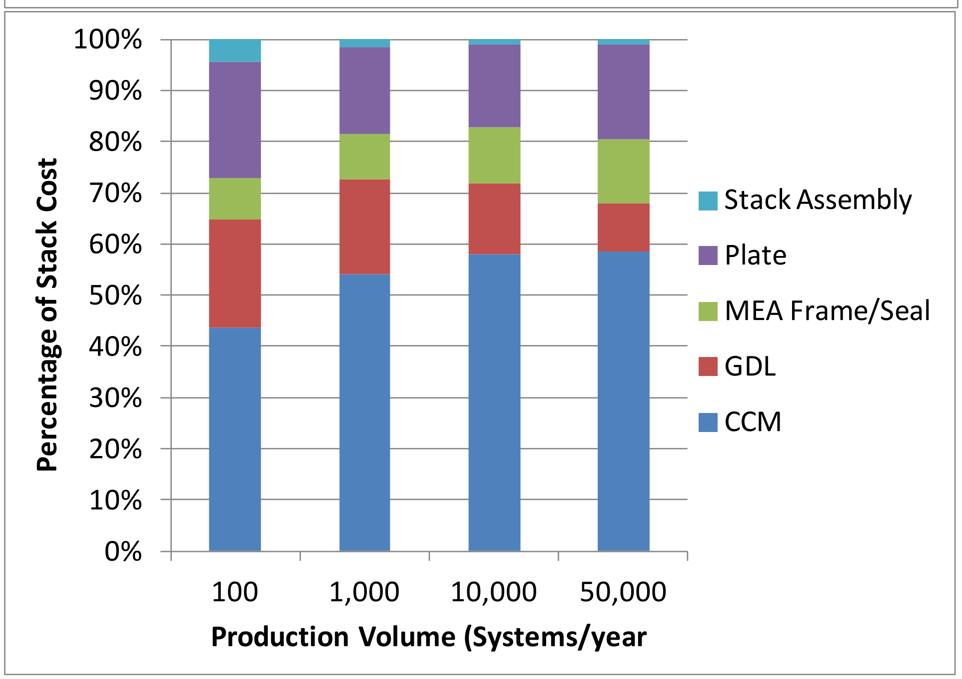


Figure 6.3. Percentage of overall fuel cell stack costs for balance of plant, fuel processor and fuel stack costs for 10 kWe and 100 kWe CHP systems with reformate fuel.

Figure 6.1 depicts direct costs for 10kWe and 100kWe as a function of annual production volume in systems per year with a tabular breakdown of costs in Table 6.1. For the stack costs, material costs dominate at high volumes. Figure 6.2 shows that for 10kWe and 100kWe CHP systems and for all of the production volumes studied here, BOP costs are greater than stack costs with the largest component from balance of plant non-fuel processor costs. BOP is a larger relative portion of system cost for lower power systems. Figure 6.3 shows stack cost components are the CCM constitute approximately half of the stack cost above an annual production of 100MW.

System Size (kW)	1				1			
Production Volume (Units/yr)	100	1000	10000	50000	100	1000	10000	50000
Stack Cost	$ 11,973	$ 2,041	$ 779	$ 540	50%	18%	9%	7%
BOP_Non-FP	$ 7,632	$ 6,226	$ 5,309	$ 4,578	32%	54%	60%	60%
BOP_FP	$ 4,239	$ 3,263	$ 2,770	$ 2,547	18%	28%	31%	33%
Total ($/kWnet)	$ 23,844	$ 11,530	$ 8,858	$ 7,665				
System Size (kW)	10				10			
Production Volume (Units/yr)	100	1000	10000	50000	100	1000	10000	50000
Stack Cost	$ 1,790	$ 590	$ 370	$ 311	44%	24%	19%	18%
BOP_Non-FP	$ 1,529	$ 1,271	$ 1,055	$ 919	38%	52%	54%	53%
BOP_FP	$ 725	$ 602	$ 527	$ 494	18%	24%	27%	29%
Total ($/kWnet)	$ 4,044	$ 2,462	$ 1,952	$ 1,724				
System Size (kW)	50				50			
Production Volume (Units/yr)	100	1000	10000	50000	100	1000	10000	50000
Stack Cost	$ 705	$ 396	$ 297	$ 260	35%	26%	24%	23%
BOP_Non-FP	$ 1,013	$ 865	$ 730	$ 631	50%	57%	58%	57%
BOP_FP	$ 293	$ 253	$ 232	$ 222	15%	17%	18%	20%
Total ($/kWnet)	$ 2,011	$ 1,514	$ 1,258	$ 1,113				
System Size (kW)	100				100			
Production Volume (Units/yr)	100	1000	10000	50000	100	1000	10000	50000
Stack Cost	$ 556	$ 346	$ 273	$ 238	36%	29%	27%	26%
BOP_Non-FP ($/kWnet)	$ 736	$ 624	$ 524	$ 458	47%	52%	52%	51%
BOP_FP ($/kWnet)	$ 262	$ 231	$ 215	$ 207	17%	19%	21%	23%
Total ($/kWnet)	$ 1,555	$ 1,201	$ 1,011	$ 903				
System Size (kW)	250				250			
Production Volume (Units/yr)	100	1000	10000	50000	100	1000	10000	50000
Stack Cost	$ 438	$ 307	$ 252	$ 220	35%	30%	28%	28%
BOP_Non-FP	$ 602	$ 521	$ 446	$ 385	48%	50%	50%	49%
BOP_FP	$ 225	$ 203	$ 194	$ 188	18%	20%	22%	24%
Total ($/kWnet)	$ 1,265	$ 1,031	$ 891	$ 792				

Table 6.2. Direct cost results for CHP fuel cell system in units of $/kWe as a function of system size and annual production volume and showing percentage of cost from stack, BOP_Non-FP (non-fuel processor balance of plant), and BOP_FP (fuel processor balance of plant).

System Size{kW}	100 Systems/ yr	1000 Systems/ yr	10000 Systems/ yr	50000 Systems/ yr	100 to 1000 Systems/ yr	1000 to 10000 Systems/ yr	10000 to 50000 Systems/ yr	100 to 50000 Systems/ yr
1	$11,973	$ 2,041	$ 779	$ 540	83%	62%	31%	95%
10	$ 1,790	$ 590	$ 370	$ 311	67%	37%	16%	83%
50	$ 705	$ 396	$ 297	$ 260	44%	25%	12%	63%
100	$ 556	$ 346	$ 273	$ 238	38%	21%	13%	57%
250	$ 438	$ 307	$ 252	$ 220	30%	18%	13%	50%

(a)

System Size{kW}	100 Systems/ yr	1000 Systems/ yr	10000 Systems/ yr	50000 Systems/ yr	100 to 1000 Systems/ yr	1000 to 10000 Systems/ yr	10000 to 50000 Systems/ yr	100 to 50000 Systems/ yr
1	$11,871	$ 9,489	$ 8,079	$ 7,125	20%	15%	12%	40%
10	$ 2,254	$ 1,873	$ 1,582	$ 1,413	17%	16%	11%	37%
50	$ 1,307	$ 1,118	$ 962	$ 853	14%	14%	11%	35%
100	$ 998	$ 855	$ 739	$ 665	14%	14%	10%	33%
250	$ 827	$ 724	$ 640	$ 573	13%	12%	10%	31%

(b)

Table 6.3. (a) Fuel cell stack cost in units of $/kWe and percentage reductions in cost in moving to higher volumes for CHP systems with reformate fuel; (b) Total balance of plant cost in units of $/kWe and percentage reductions in cost in moving to higher volumes.

Table 6.2 summarizes direct cost results for all system sizes and annual production volumes underscoring the overall theme that under the assumptions made in this study, BOP costs are a larger fraction of system costs and that this is more pronounced at small system sizes, as BOP costs are more "spread out" for larger system sizes while smaller systems do not realize this scaling advantage. Table 6.3 shows that stack costs scale more rapidly with volume than BOP components. Stack costs drop rapidly at low system sizes and low volumes (Table 6.3a) and then scale by 13-21% per ten-fold increase in volume for larger system sizes above 1000 systems per year.

6.2 CHP Customer Costs

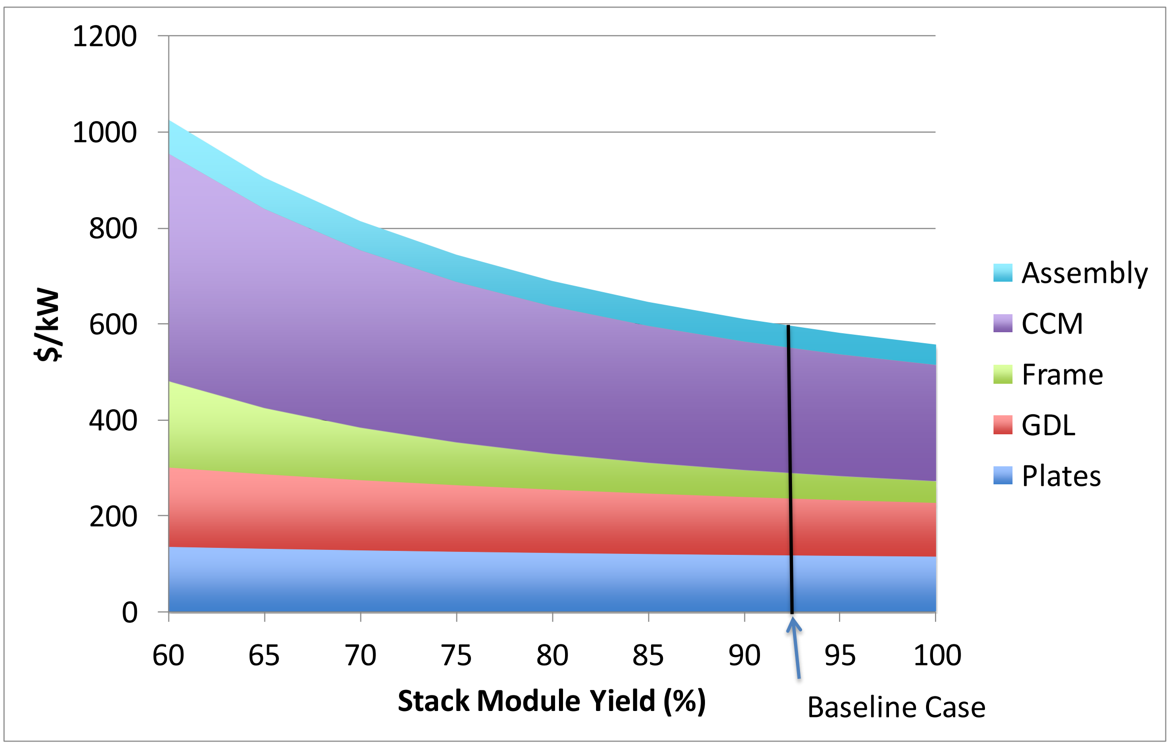
In this section we estimate customer costs for 10kWe and 100kWe CHP systems based on the direct manufacturing costs above and compare them to DOE targets for 2015 and 2020. In Figure 6.1, there is a fixed yield at each annual production volume. In this section, we also present stack cost sensitivity to varying stack module yield at a fixed production volume. Stack module yield is the process yield at each stack module (CCM, GDL, bipolar plates, frame and seal). Stack assembly however is not allowed to vary and is held at 99% since any losses in assembly would be extremely costly and are assumed to be minimized at all times.

A markup of 50% is taken for non-manufacturing corporate costs such as general and administrative, and sales and marketing as discussed in Section 3.1. This corporate markup can vary with several factors including market conditions, the research and development stage of the company and other factors, but is taken as a fixed value for simplicity here.

Figure 6.4 (a) and (c) show the fuel cell stack direct cost for a 10kWe CHP system at 1000 and 50,000 systems per year respectively. Stack costs are a strong function of stack module yield with a reduction of about 45% across the yield range of 60-100%. Also shown is the baseline case's approximate stack module yield[7] corresponding to Figure 6.1(a).

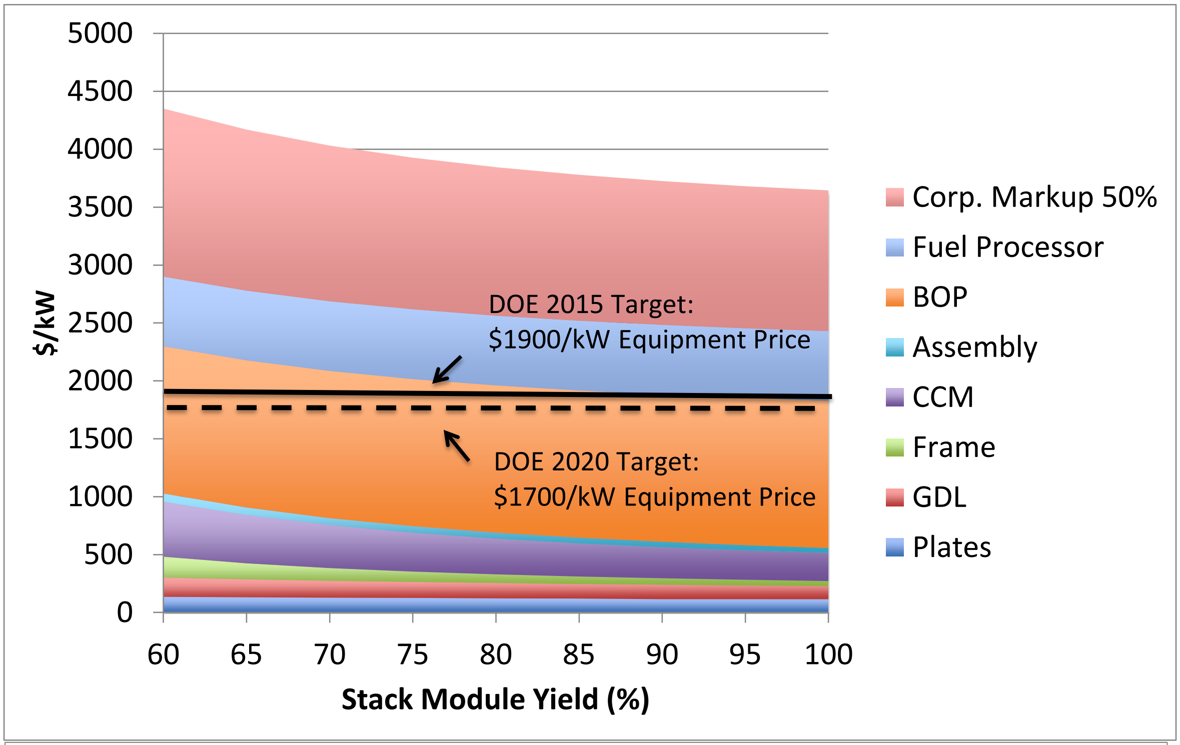
Equipment cost including corporate markup is estimated to be $3600-4400/kWe at 1000 systems per year and $2600-3000/kWe for 50000 systems per year. In both cases the overall cost is above the 2015 and 2020 DOE equipment cost target of $1900/kWe and $1700/kWe, respectively. The largest cost component is seen to be the BOP (not including fuel processor) and this is a key area for further cost reduction.

(a)

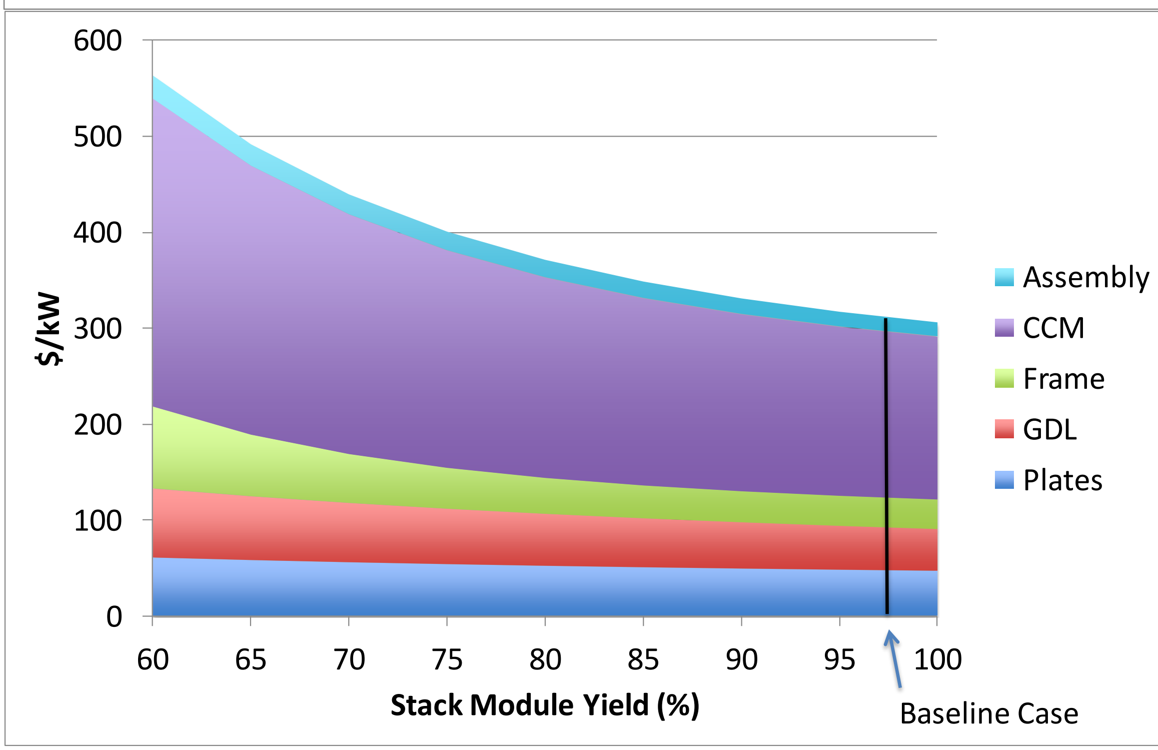


[7] Note that in Figure 6.1 each stack module has a fixed yield but all modules do not necessarily have the same yield as is assumed in Figure 6.5.

(b)


5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
$/kW
DOE 2015 Target:
$1900/kW Equipment Price
DOE 2020 Target:
$1700/kW Equipment Price
60
65
70
75
80
85
90
95
100
Stack Module Yield (%)
Corp. Markup 50%
Fuel Processor
BOP
Assembly
CCM
Frame
GDL
Plates

(c)


600
500
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200
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Stack Module Yield (%)
Baseline Case
Assembly
CCM
Frame
GDL
Plates

(d)

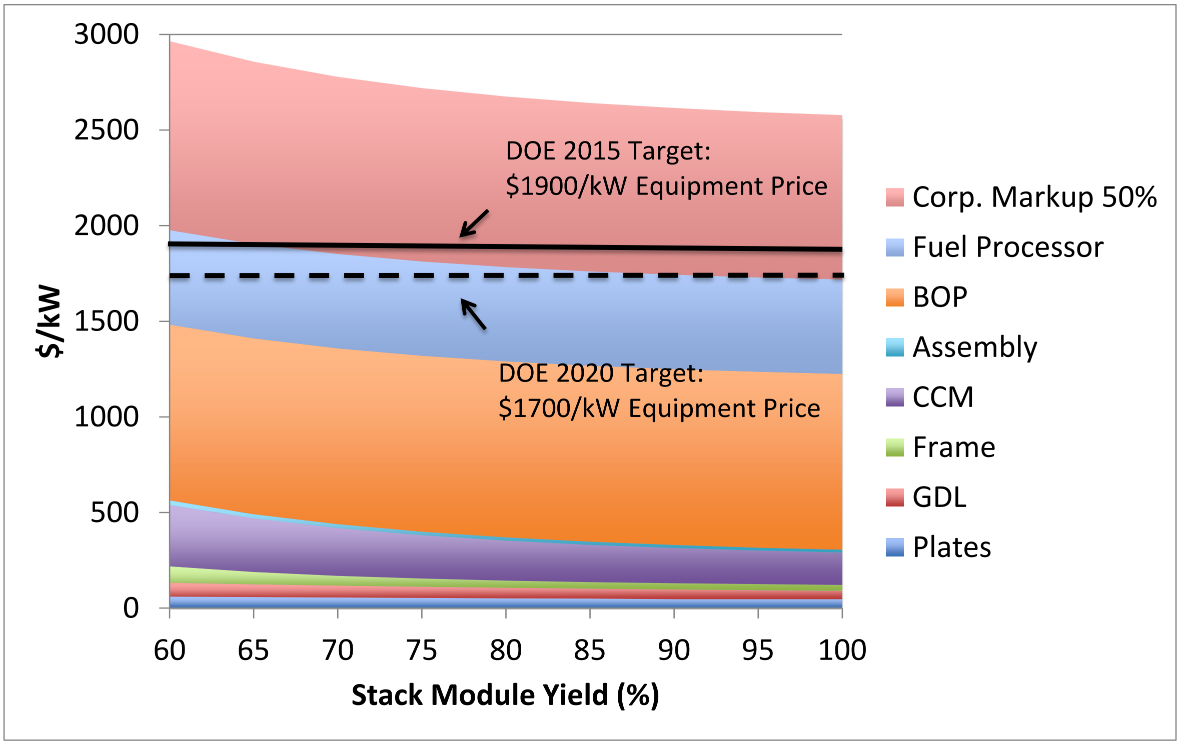


Figure 6.4. (a) Direct cost of fuel cell stack vs. stack module yield and (b) equipment cost including corporate markup for 10kWe CHP system,1000 systems per year[8]; (c) Direct cost of fuel cell stack vs. stack yield and (d) equipment cost including corporate markup for 10kWe CHP system, 50000 systems per year.

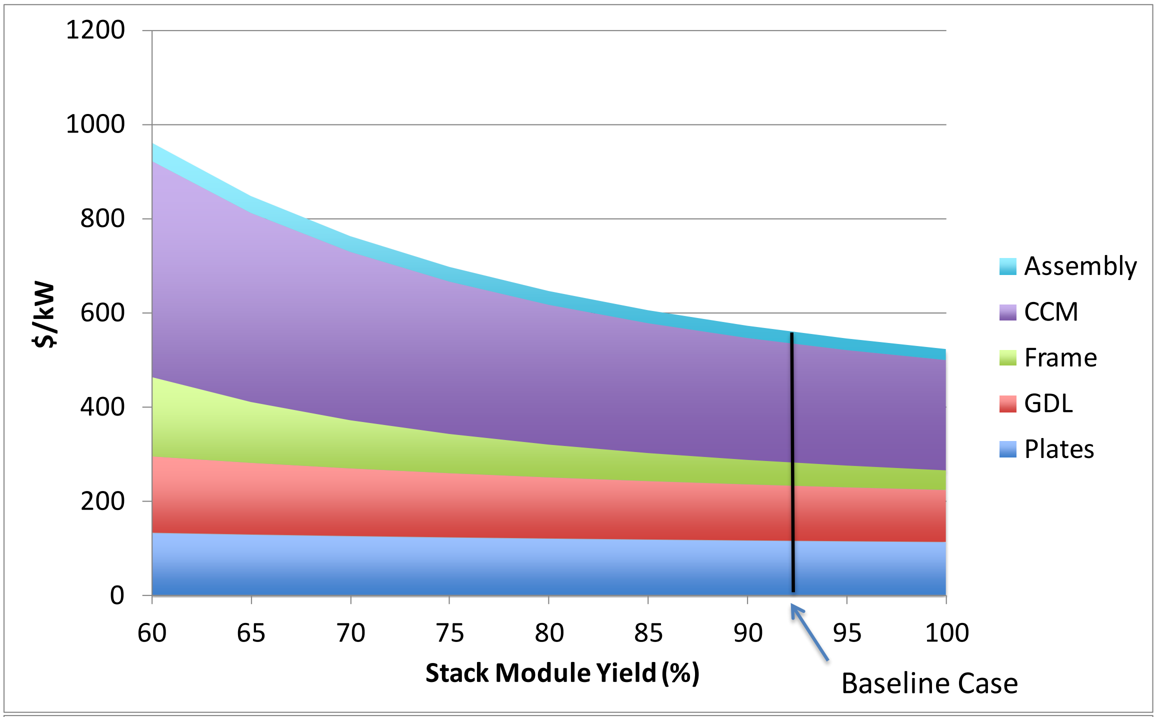
CHP installed costs for a 100kWe system with reformate fuel are shown in Figure 6.5. Figure 6.5(a) and (c) show direct cost for a fuel cell stack vs. stack module yield for 100 and 50,000 systems per year, respectively, Stack cost is a strong function of stack module yield, with a near halving in stack cost as module yield varies from 60-100% in Fig. 6.5(a). Also shown is the baseline case's approximate stack module yield for 100kWe systems that is assumed in Figure 6.1(b).

Figures 6.5(b) and (d) show the installation costs for a 100kWe CHP system again at 100 and 50,000 systems per year, respectively. Balance of plant costs are a fixed cost added to the stack cost. In addition to a 50% corporate markup, a 33% markup is taken for installation and all other "soft costs" such as permitting and project management fees. This work did not explore these soft costs in detail but relies on other sources for this installation cost (e.g., EPA 2008). Figure 6.5(b) and (d) show that the 100kWe CHP system can nearly meet the $3000/kWe installed cost target for 100kWe at 100 systems per year and can meet the 2015 target at 50,000 systems per year, but in both cases, additional cost reduction is required to meet the 2020 target.

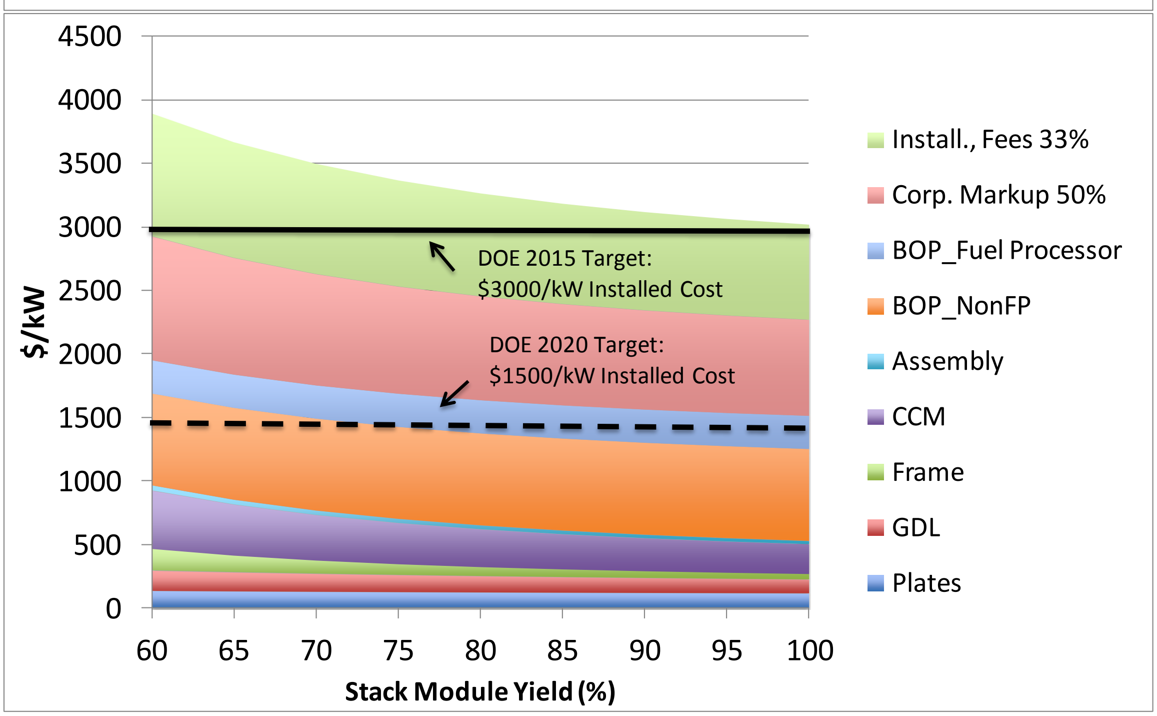
[8]The 10kWe stack direct costs shown in Figure 6.4(a) and Table 6.3(a) are consistent with the Manufacturing Fuel Cell Manhattan Project (Sousa, 2011) which estimates a 10kWe stack cost of $797/kWe (about $850/kWe at current prices) at 5000 systems per year, but with a low stack module yield in the 60% range. This work estimates $1010/kWe ($630/kWe) direct cost for a 10kWe stack at an annual volume of 1000 systems per year and 10,000 systems per year, respectively, at 60% module yield (Table 6.3(a) shows cost at nominal high yield), or about $800/kWe at 5000 systems per year.

Referring to Table 6.2, installed cost including corporate markup is estimated to be about double the direct system cost, or $3077/kWe for 100kWe systems at an annual volume of 100 systems per year and $1810/kWe at 50,000 systems per year. Thus, costs would need a further 51% reduction to meet the 2020 cost target of $1500/kW at the 100 systems per year annual production volume and 17% further cost reduction at 50,000 systems per year.

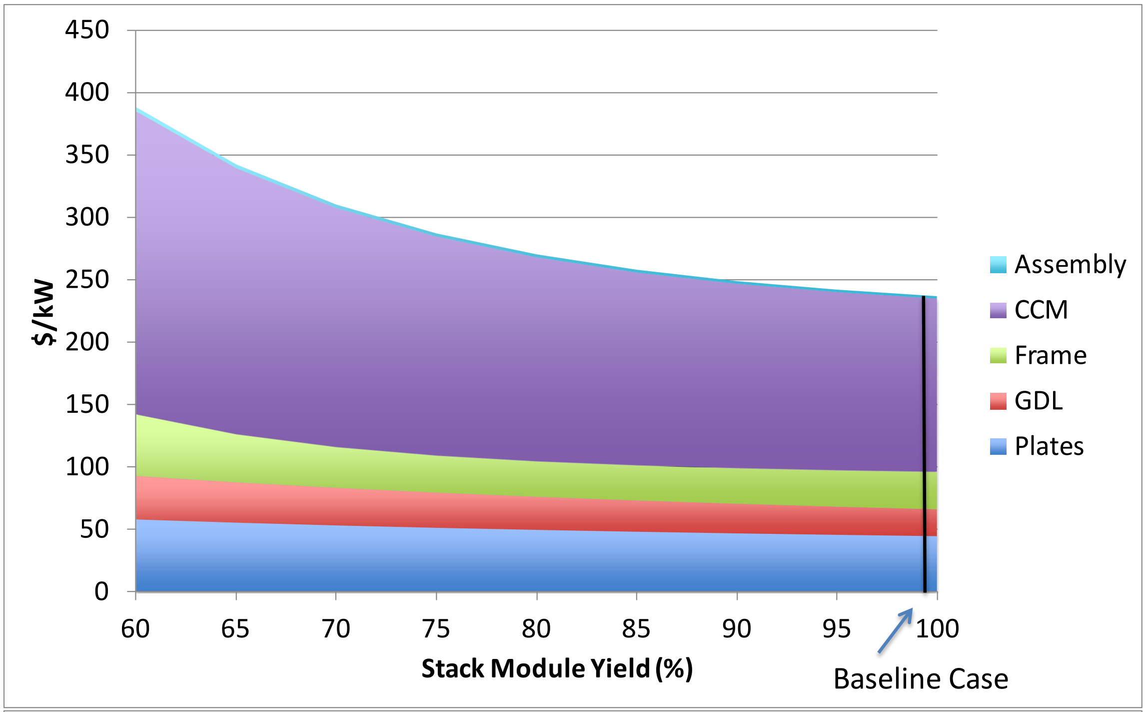
(a)



(b)



(c)



(d)

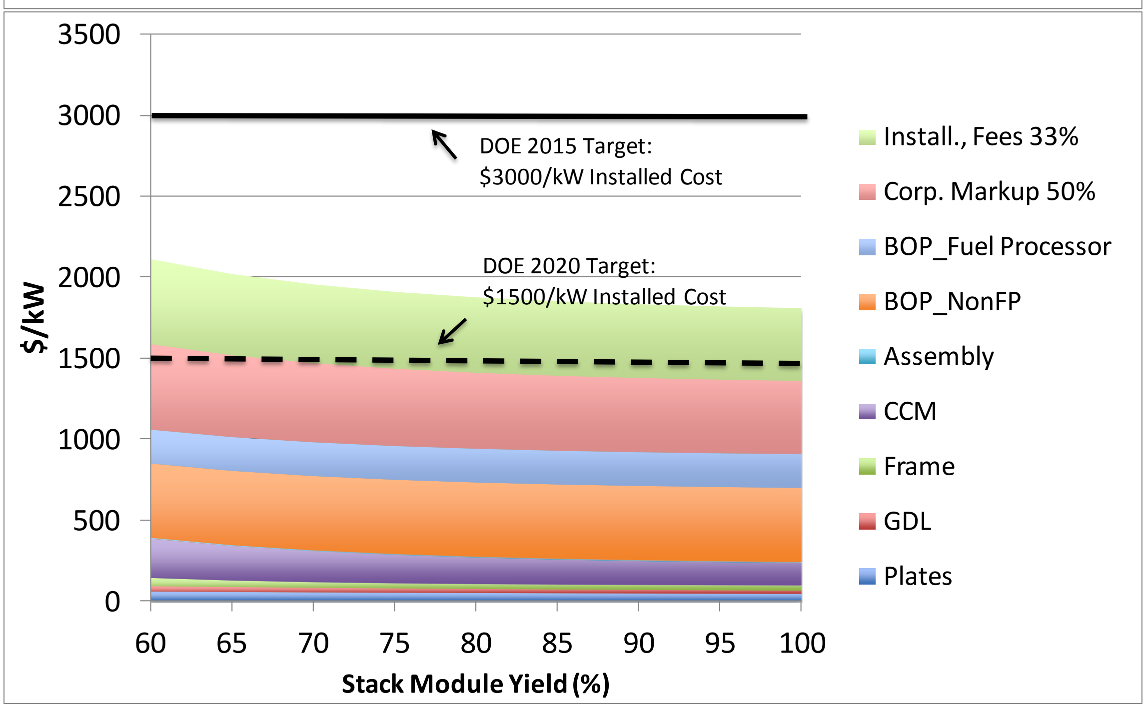


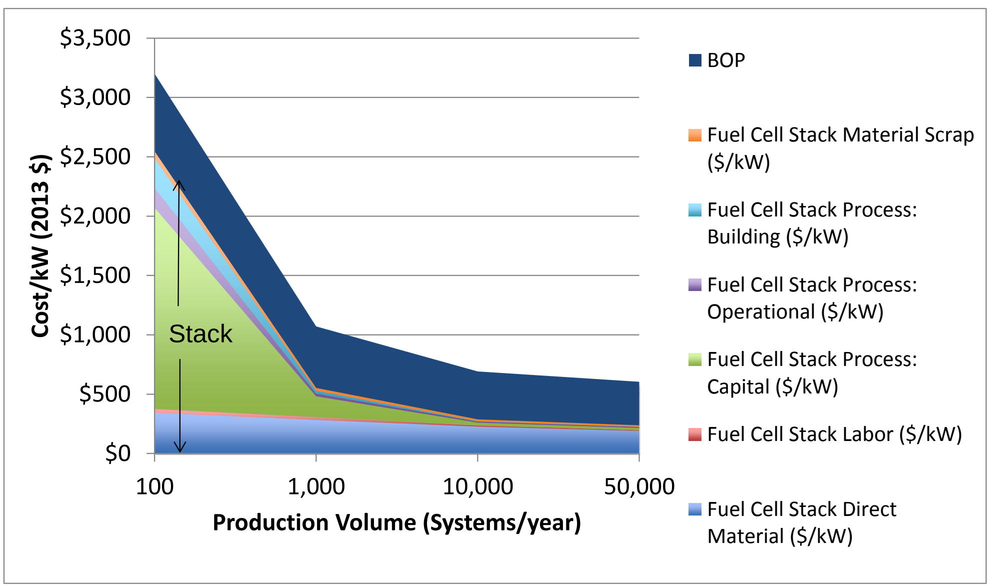
Figure 6.5. (a) Direct cost of fuel cell stack vs. stack module yield for 100kWe CHP system,100 systems per year; (b) Installed cost for 100kWe CHP system, 100 systems per year; (c) Direct cost of fuel cell stack vs. stack yield for 100kWe CHP system, 50,000 systems per year; (d) Installed cost for 100kWe CHP system, 50,000 systems per year.

6.3 System Results for Backup Power Systems with Metal Bipolar Plates

Detailed system cost plots as a function of manufacturing volume are presented in Figure 6.6 and Table 6.4 for backup power system with metal bipolar plates for the 10kWe and 50 kWe system sizes.

Figure 6.6 shows stack costs with the assumption of vertical integration. A percentage breakdown of overall system costs and stack costs are shown in Figures 6.7 and 6.8, respectively for the vertically integrated case. Additional cost plots can be found in Appendix D. Figure 6.7(a) shows that BOP costs are lower relative fraction of system costs than the CHP case since the BOP is much simpler for the backup power system. At low production volumes the stack is a greater fraction of overall system cost, and with increasing volume stack cost is between 40% and 50% of overall system cost. At low volume (10kWe x 100 systems) per year, stack costs are dominated by the metal plate as shown in Figure 6.8(a). Figure 6.8 shows stack component costs and again the CCM is the costliest component at higher volumes, followed by the plate and GDL, depending on the production volume. Backup power direct costs with a "make vs. buy" option for metal plates are presented in Section 6.6 below, and purchased metal plates can greatly reduce the system cost at low volumes.

(a) 10kWe



(b) 50kWe

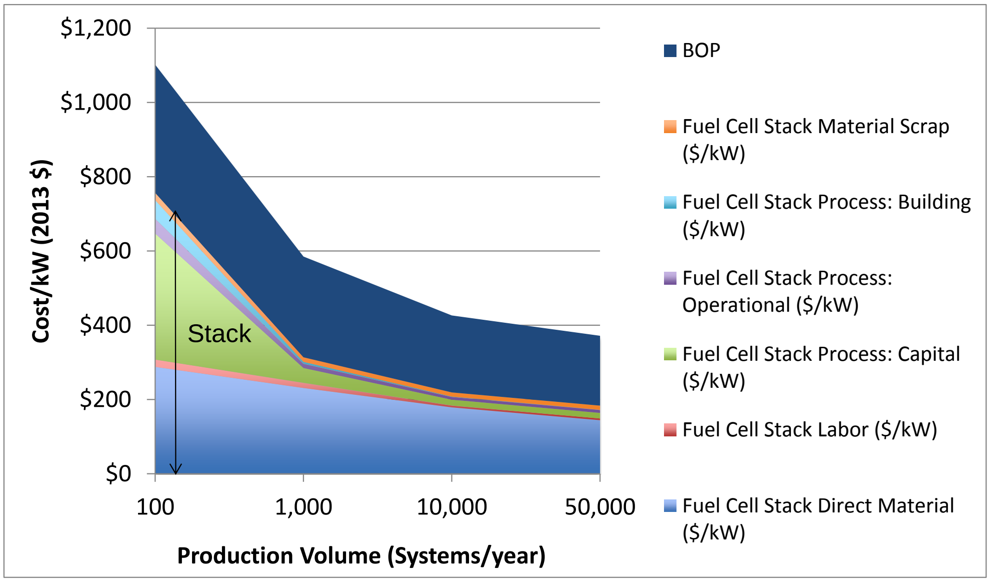


Figure 6.6. Overall fuel cell system costs for backup power application.

System Size (kW)	10			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Fuel Cell Stack Direct Material ($/kW)	344.18	282.93	226.98	190.27
Fuel Cell Stack Labor ($/kW)	31.53	23.73	9.53	6.28
Fuel Cell Stack Process: Capital ($/kW)	1,697.17	174.75	24.72	18.80
Fuel Cell Stack Process: Operational ($/kW)	164.34	24.51	8.80	8.13
Fuel Cell Stack Process: Building ($/kW)	251.30	22.60	2.36	1.11
Fuel Cell Stack Material Scrap ($/kW)	59.24	24.70	16.57	13.80
Fuel Cell Stack Cost Subtotal	2,548	553	289	238
BOP	653	518	403	366
Total ($/kWe)	3,201	1,071	692	605

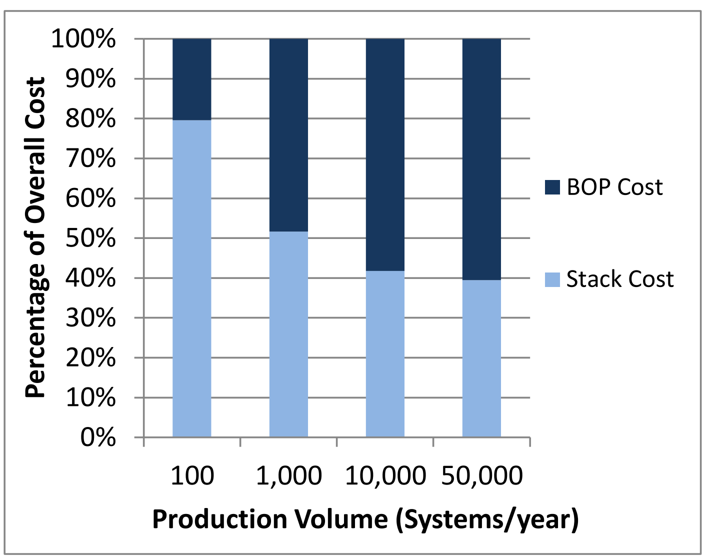
(a)

System Size (kW)	50			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Fuel Cell Stack Direct Material ($/kW)	287.88	231.23	178.89	144.26
Fuel Cell Stack Labor ($/kW)	19.76	13.54	4.95	4.53
Fuel Cell Stack Process: Capital ($/kW)	339.37	40.29	15.74	15.10
Fuel Cell Stack Process: Operational ($/kW)	39.51	11.40	7.59	7.82
Fuel Cell Stack Process: Building ($/kW)	50.38	4.81	0.87	0.64
Fuel Cell Stack Material Scrap ($/kW)	19.78	12.83	11.11	10.97
Fuel Cell Stack Cost Subtotal	757	314	219	183
BOP	345	271	208	188
Total ($/kWe)	1,102	585	427	372

(b)

Table 6.4. System Cost breakdown for 10 kWe and 50 kWe backup power system with metal plates and direct H_2 fuel.

(a)10kWe



(b) 50kWe

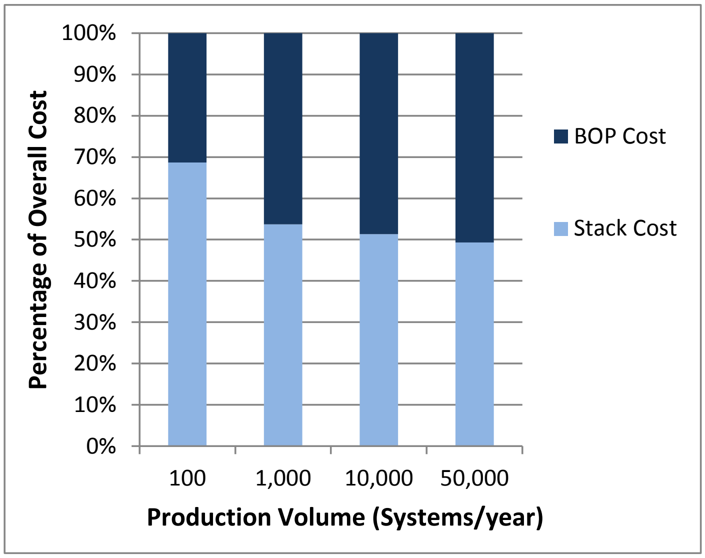
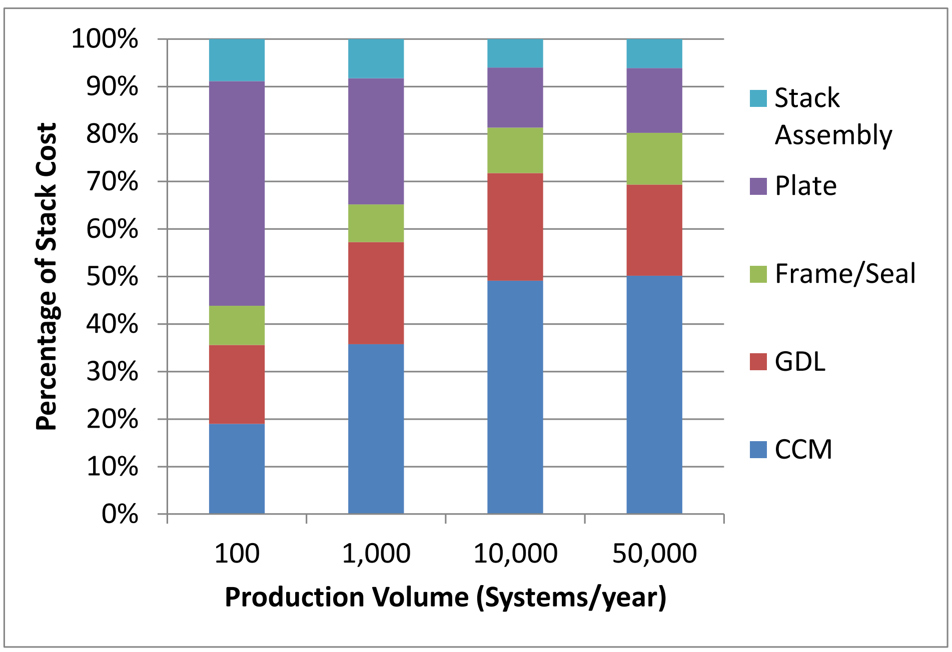


Figure 6.7. Percentage of overall fuel cell system costs for BOP and stack for 10 kWe and 50 kWe backup power application.

(a)10kWe



(b)50kWe

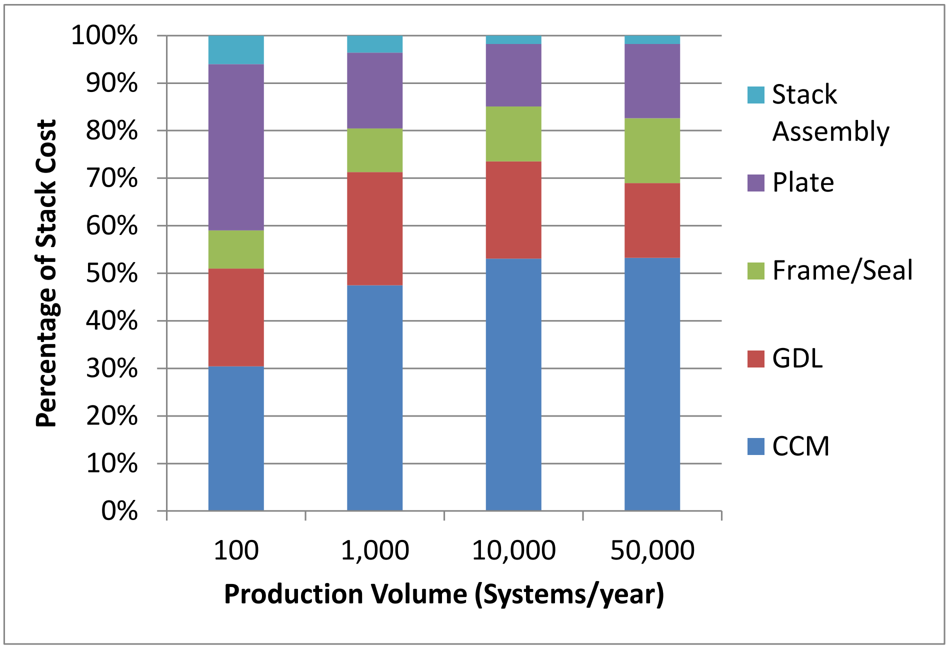


Figure 6.8. Percentage of overall fuel cell stack costs for 10 kWe and 50 kWe backup power application.

Tables 6.5 and 6.6 show a summary of direct costing results for backup power systems. Trends are qualitatively similar to the CHP case, but stack costs are a larger relative fraction of system costs.

	1				1			
Production Volume (Systems/yr)	100	1000	10000	50000	100	1000	10000	50000
Stack Cost	13230	2821	752	458	79%	50%	25%	19%
BOP	3597	2852	2235	2008	21%	50%	75%	81%
Total ($/kWnet)	16827	5673	2987	2466				
System Size (kW)	10				10			
Production Volume (Systems/yr)	100	1000	10000	50000	100	1000	10000	50000
Stack Cost	2548	553	289	238	80%	52%	42%	39%
BOP Cost	653	518	403	366	20%	48%	58%	61%
Total ($/kWnet)	3201	1071	692	605				
System Size (kW)	25				25			
Production Volume (Systems/yr)	100	1000	10000	50000	100	1000	10000	50000
Stack Cost ($/kWnet)	1630	449	260	214	80%	58%	50%	48%
BOP ($/kWnet)	420	331	255	231	20%	42%	50%	52%
Total ($/kWnet)	2050	780	515	445				
System Size (kW)	50				50			
Production Volume (Systems/yr)	100	1000	10000	50000	100	1000	10000	50000
Stack Cost ($/kWnet)	757	314	219	183	69%	54%	51%	49%
BOP ($/kWnet)	345	271	208	188	31%	46%	49%	51%
Total ($/kWnet)	1102	585	427	372				

Table 6.5. Direct cost results for backup power fuel cell system in units of $/kWe as a function of system size and annual production volume and showing percentage of cost from stack and BOP.

System Size{kW}	100 Systems/yr	1000 Systems/yr	10000 Systems/yr	50000 Systems/yr	100 to 1000 Systems/yr	1000 to 10000 Systems/yr	10000 to 50000 Systems/yr	100 to 50000 Systems/yr
1	$ 13,230	$ 2,821	$ 752	$ 458	79%	73%	39%	97%
10	$ 2,548	$ 553	$ 289	$ 238	78%	48%	18%	91%
25	$ 1,630	$ 449	$ 260	$ 214	72%	42%	18%	87%
50	$ 757	$ 314	$ 219	$ 183	58%	30%	16%	76%

(a)

System Size{kW}	100 Systems/yr	1000 Systems/yr	10000 Systems/yr	50000 Systems/yr	100 to 1000 Systems/yr	1000 to 10000 Systems/yr	10000 to 50000 Systems/yr	100 to 50000 Systems/yr
1	$ 3,597	$ 2,852	$ 2,235	$ 2,008	21%	22%	10%	44%
10	$ 653	$ 518	$ 403	$ 366	21%	22%	9%	44%
25	$ 420	$ 331	$ 255	$ 231	21%	23%	10%	45%
50	$ 345	$ 271	$ 208	$ 188	22%	23%	9%	45%

(b)

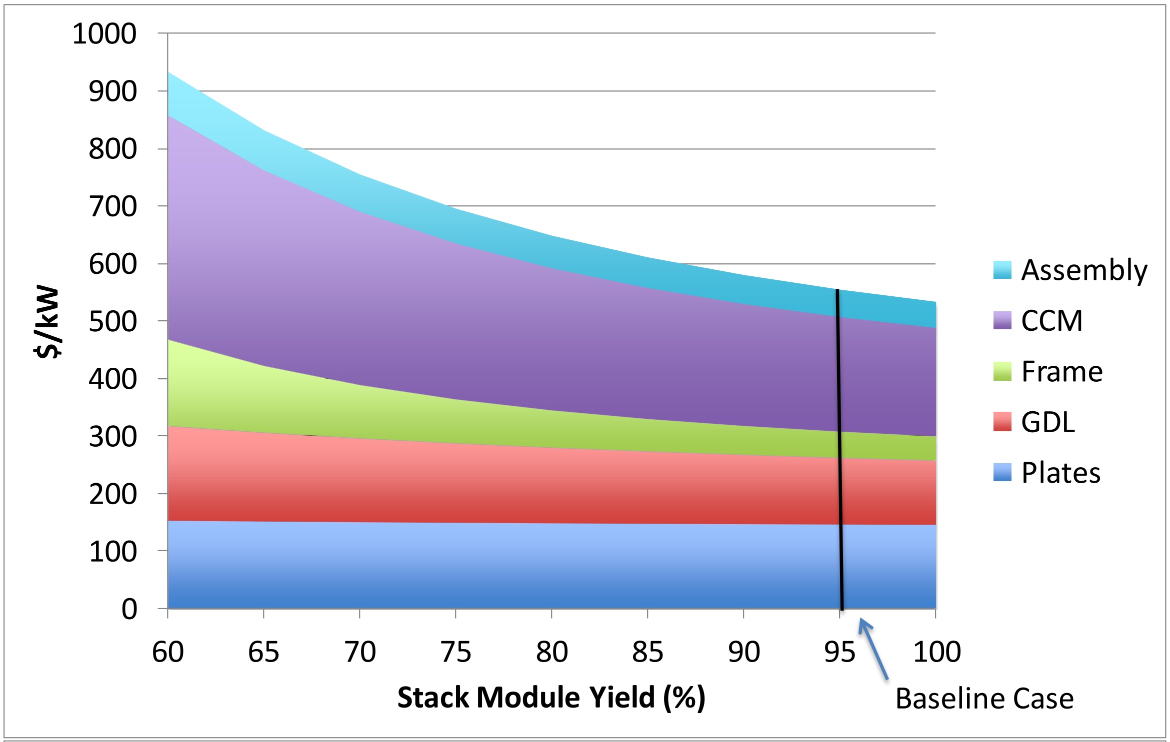
Table 6.6. (a) Fuel Cell Stack cost in units of $/kWe and percentage reductions in cost in moving to higher volumes for backup power systems; (b) Balance of plant cost in units of $/kWe and percentage reductions in cost in moving to higher volumes.

6.4 Backup Power Installed Costs

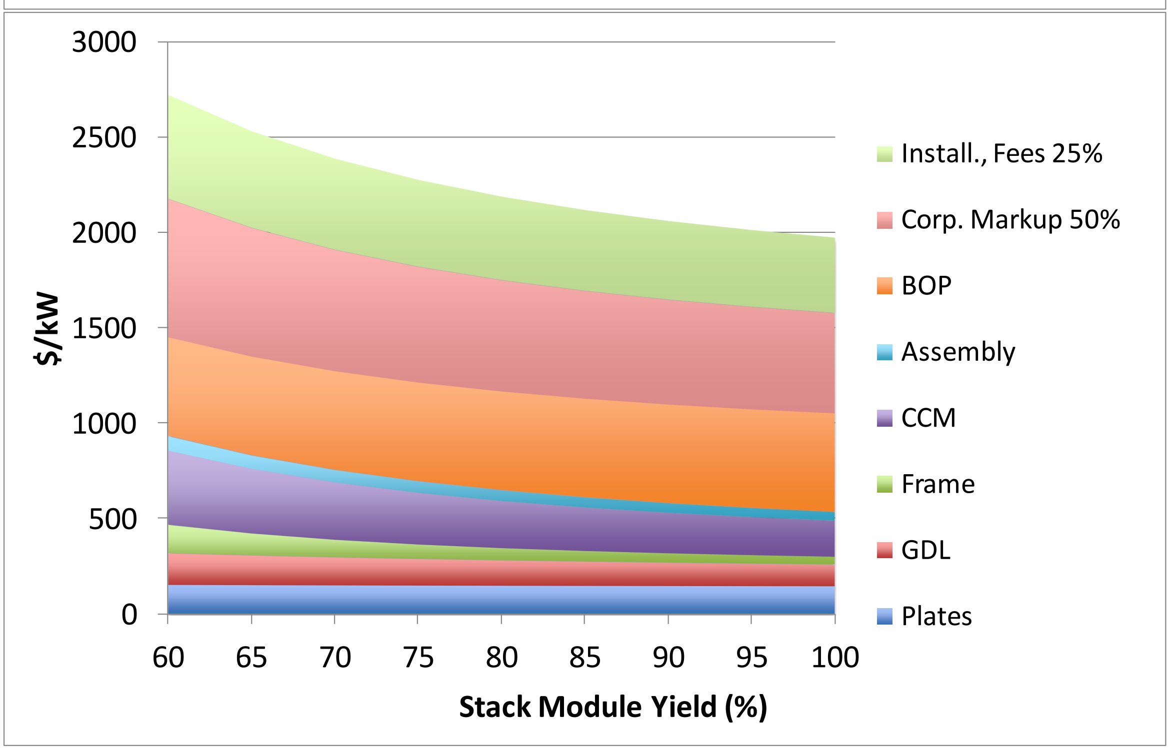
Backup power installed costs for a 10kWe system with direct H_2 are shown in Figure 6.9. Figure 6.9(a) and (c) show direct cost for fuel cell stack vs. stack module yield for 1000 and 50,000 systems per year, respectively. Stack cost is a strong function of stack module yield, with 42-45% reduction in stack cost as yield varies from 60% to 100%. Also shown is the baseline case approximate stack module yield for 10kWe systems that is assumed in Figure 6.6(a).

Figures 6.9(b) and (d) show the installation costs for a 10kWe backup power system again at 1000 and 50,000 systems per year, respectively. Balance of plant costs are a fixed cost added to stack cost. In addition to a 50% corporate markup as before, a 25% further markup is taken for installation and fees which include all other "soft costs" such as permitting. The installation factor is assumed to be lower than the CHP case since the installation is expected to be simpler and incur less overall fees such as project management fees. Overall installed cost is found to be $1970-2700/kWe at 1000 systems per year and $1100-1500/kWe at 50,000 systems per year.

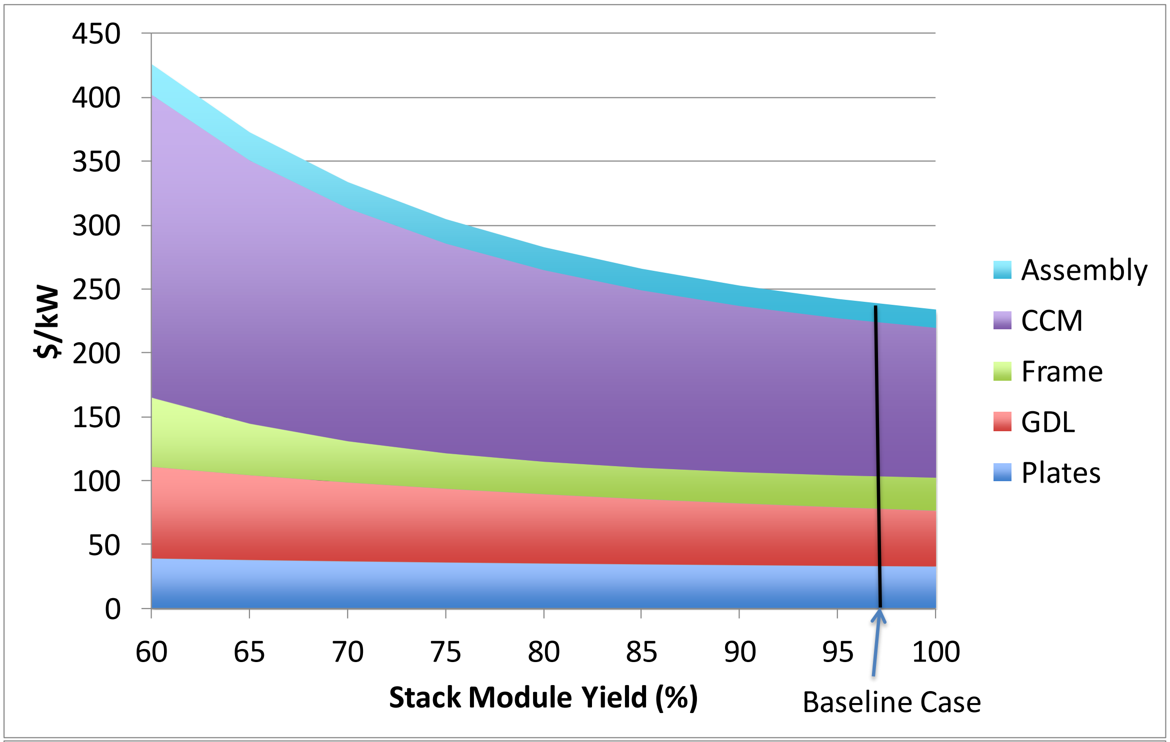
(a)


1000
900
800
700
600
500
400
300
200
100
0
$/kW
60
65
70
75
80
85
90
95
100
Stack Module Yield (%)
Baseline Case
Assembly
CCM
Frame
GDL
Plates

(b)


3000
2500
2000
1500
1000
500
0
$/kW
60
65
70
75
80
85
90
95
100
Stack Module Yield (%)
Install., Fees 25%
Corp. Markup 50%
BOP
Assembly
CCM
Frame
GDL
Plates

(c)



(d)

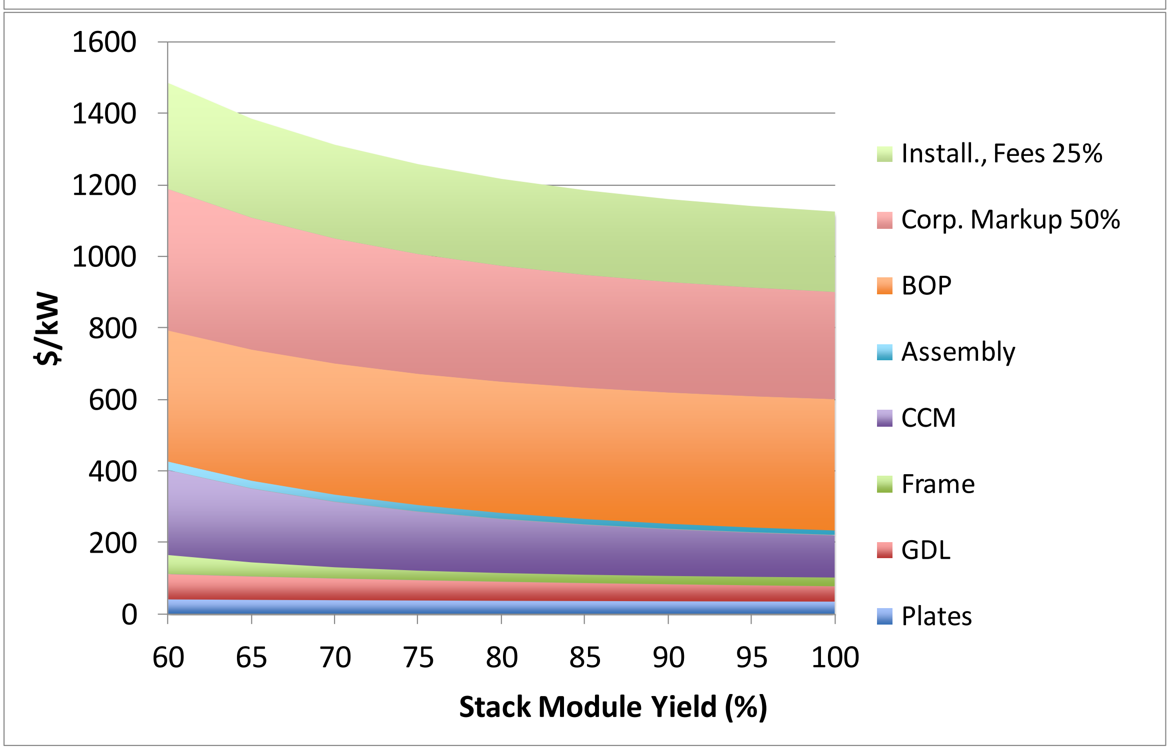


Figure 6.9. (a) Direct cost of fuel cell stack vs. stack module yield for 10kWe backup system,1000 systems per year; (b) Installed cost for 10kWe backup power system, 1000 systems per year; (c) Direct cost of fuel cell stack vs. stack yield for 10kWe backup power system, 50,000 systems per year; (b) Installed cost for 10kWe backup power system, 50,000 systems per year.

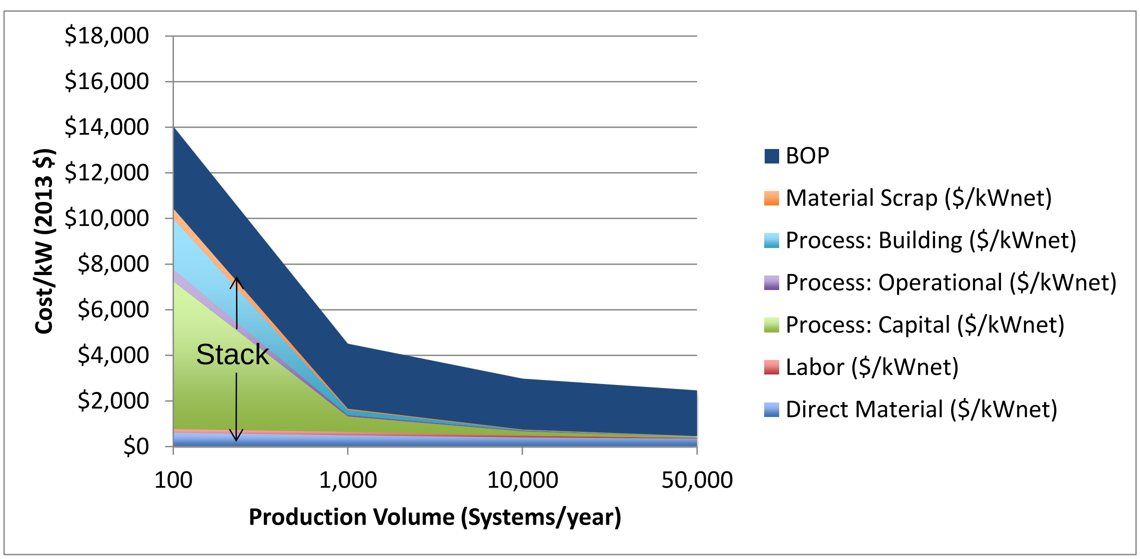
6.5 Low Volume Cost Considerations

At 1 kWe and low volumes, extremely high costs per kWe are derived here. This high cost at low system size and production volume is mainly a result of two assumptions in the analysis: (1) vertical integration has been assumed instead of purchasing parts or contract manufacturing, and (2) the choice of equipment throughout the entire analysis is geared to higher volume manufacturing. Regarding the first point, vertically integrated stack manufacturing (purchasing membrane, carbon paper, and but manufacturing other stack components) is assumed for all production volumes, but at low volume, overall stack costs can be less by purchasing stack components such as metal plates for backup power systems and assembling them in-house. Regarding the second point, at low system sizes and production volumes, the capacity utilization of the manufacturing equipment is low, and therefore, the capital costs per unit produced are high. The DFMA costing in Chapter 4 generally starts with equipment that can produce > 1,000 systems per year (e.g., metal plates, CCM deposition, GDL). The team did not further optimize the manufacturing process for low power, low capacity parts (e.g., 1kWe, 100 systems per year).

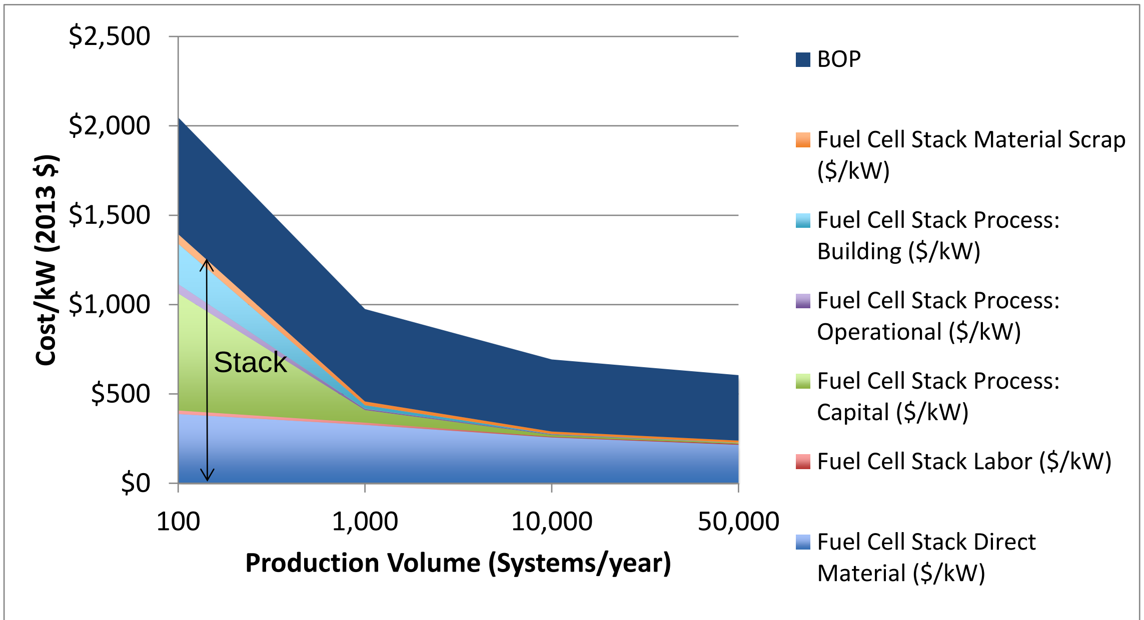
6.6 Backup Power Direct Costs with Make vs Buy Metal Plate Option

As an example of a make vs buy option at lower volumes, fuel cell direct costs for BU power with make vs buy option exercised for metal plates are shown in Figure 6.10. Here, purchased metal plates are selected over in-house manufacturing whenever the cost of purchased plates is lower than that for in-house manufacturing. Compared to Figure 6.6 and Table 6.5 above, at 100 and 1000 systems per year it is more cost effective to purchase metal plates for 1kW and 10kW system sizes, and costs are seen to be reduced by purchasing metal plates for 1kWe, 10kWe and 50 kWe system sizes at lower volumes. .

(a)1 kWe



(b) 10 kWe



(c) 50 kWe

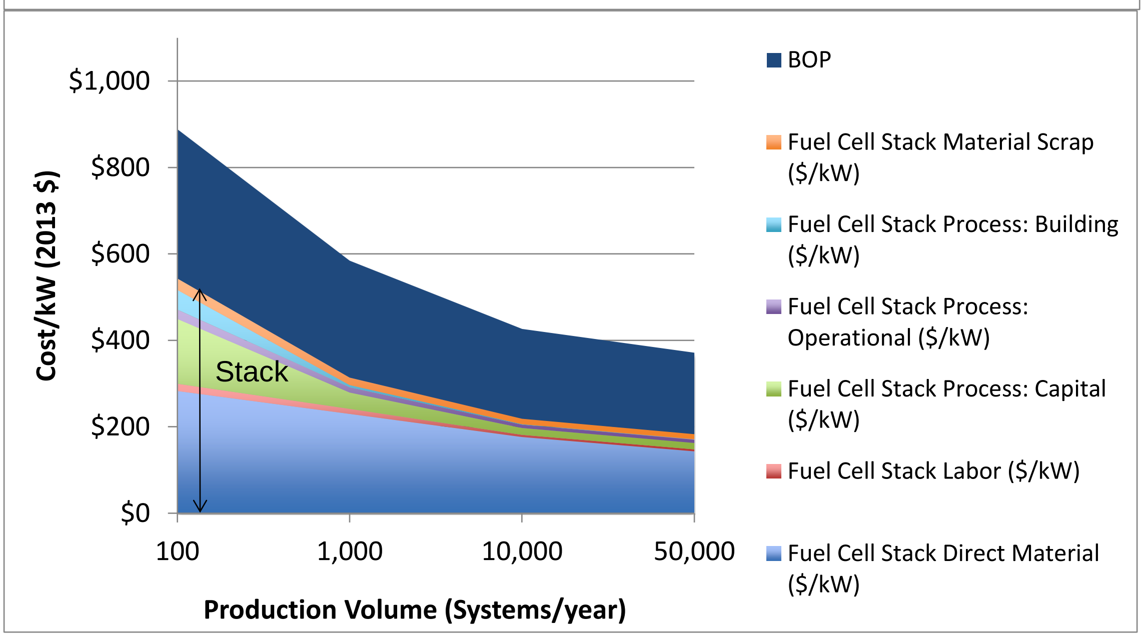


Figure 6.10. Fuel cell direct cost for BU power with make vs buy option exercised for metal plates. Compared to Figure 6.6 above, costs at 100 and 1000 systems per year are reduced by purchasing metal plates for 1kWe, 10kWe and 50 kWe system sizes.

7 Total Cost of Ownership Modeling of CHP Fuel Cell Systems

Modeling the "total cost of ownership" (TCO) of fuel cell systems involves considering capital costs, fuel costs, operating costs, maintenance costs, "end of life" valuation of recoverable components and/or materials, valuation of externalities and comparisons with a baseline or other comparison scenarios. When externalities are included in TCO analysis, both "private" and "total social" costs can be considered to examine the extent to which they diverge and there are un-priced impacts of project implementation. These divergences can create market imperfections that lead to sub-optimal social outcomes, but in ways that are potentially correctible with appropriate public policies (e.g., applying prices to air and water discharges that create pollution).

TCO analysis also critically depends on the assumed duty cycle of operation of the equipment, resulting in the system "capacity factor" or utilization factor.[9] For some systems this is relatively clear – e.g., back-up systems can be expected to operate occasionally for brief durations. However, for grid-connected CHP systems this is far less clear. The optimal (most economic) duty cycle for any given CHP installation depends on several complex factors, including site variables, prevailing utility rates and "standby charges,"[10] and site requirements. Various types of tools and analyses can help to address these key TCO considerations. In this chapter, we present the key components of the TCO model including life cycle cost modeling (LCC) and life cycle impact assessment modeling (LCIA), taking as an input the installed system costs presented in the previous chapter.

A rolled up summary of the model is described in the final section on "TCO Modeling" for several commercial building types in six different cities including Phoenix, Minneapolis, Chicago, New York City, Houston, and San Diego. These cities were chosen to represent several climate zones within the United States and to sample regions of the U.S. with differing mixes of grid-supplied electricity. Comparisons for FC CHP systems are to a "baseline" case of grid based electricity and conventional fuel-based heating systems (e.g. gas-fired water heaters and boiler systems). An LCC, LCIA, or TCO comparison with other technologies such as fossil fuel-fired or biomass-based CHP systems was not in the scope of this work but could be explored in future work.

7.1 Life Cycle Assessment (LCA) Model

According to the Environment Protection Agency (EPA, 2014a), life cycle assessment (LCA) can be defined as a technique to assess the environmental aspects and potential impacts associated with a product, process, or service, by studying and analyzing the following:

- Inventory of relevant energy and material inputs and environmental releases
- Potential environmental impacts associated with identified inputs and releases

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[9] In this report, system availability is the percentage of hours in the year that the FCS is available for operation. For example, the system may not be available some hours due to scheduled maintenance. The system utilization is then defined as the percentage of kWhe produced by the fuel cell system out of the total kWhe of potential output at the nameplate power rating of the system and for the available hours of operation.

[10] Standby rates are charges levied by utilities when a distributed generation system, such as an on-site CHPsystem, experiences a scheduled or emergency outage, and then must rely on power purchased from the grid. These charges are generally composed of two elements: energy charges, in $/kWh, which reflect the actual energy provided to the CHP system; and demand charges, in $/kW, which attempt to recover the costs to the utility of providing capacity to meet the peak demand of the facility using the CHP system. Source: ACEEE, http://www.aceee.org/topics/standby-rates, accessed 5/29/14.

The LCA101 document published by EPA, entitled "Life Cycle Assessment: Principles and Practice," provides an introductory overview of Life Cycle Assessment and describes the general uses and major components of LCA.

A typical LCA is made up from four stages including (Rooijen, 2006; Baratto, and Diwekar, 2005):

- Goal and scope definition
- Inventory analysis
- Impact assessment
- Interpretation

In this chapter an LCA model is developed to analyze include energy, greenhouse gas emissions (GHG) and cost analysis associated with adoption of fuel cell systems in some commercial buildings within United States. LCA contains detailed analysis starting from pre-manufacturing and going to manufacturing, use and maintenance, and end-of-life phases (Figure 7.1). LCA also can include another phase that accounts for the impacts associated with fuel extraction and processing.

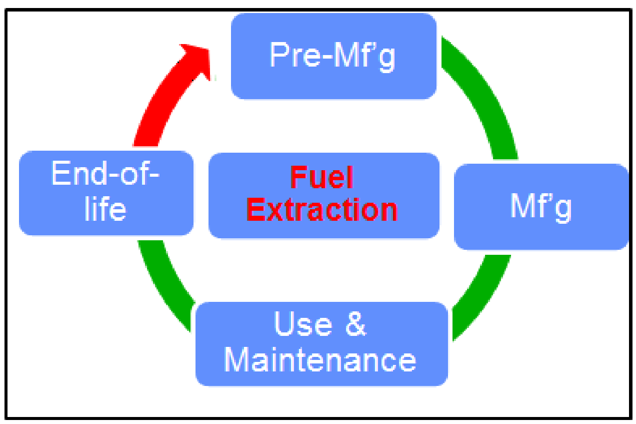


Figure 7.1. Life cycle assessment loop showing different lifetime phases

The objectives of this model are to (1) provide a LCA model for a representative LT PEM fuel cell system and to (2) provide a use-phase model of life-cycle costs of ownership including environmental assessments. Section 7.1.1 below discusses the use-phase model since it is the dominant phase for a FCS, while detailed analyses for other LCA phases are included in Appendix F.

7.1.1 Use-phase Model

Use-phase is defined as the operational phase of the fuel cell system when it is functioning in the field as a backup, stationary power, or CHP system. Use-phase is the most demanding phase among LCA phases in terms of energy and cost and has the greatest GHG impact among all phases. Fig. 7.2 below shows the sequence of steps in developing the use-phase model. The current use-phase model is developed for a CHP system operating on reformate fuel produced from natural gas input fuel, with the reforming process is assumed to be onsite. GHG emission analysis is based on the emissions associated with the reforming process and does not include fuel extraction and transportation.

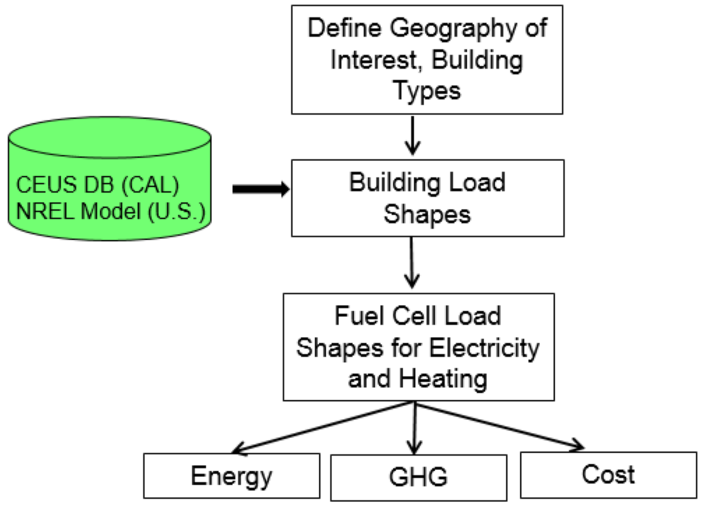


Figure 7.2. Flow chart showing methodology used in developing the use-phase model.

Inventory tables for the use-phase model includes the following information:

- Prices of electricity and natural gas (NG). Electricity prices for peak/off-peak and demand charges as well as NG prices for several locations in U.S. have been compiled and stored in the model based on 2009-2013 EIA data and a national database of utility rates[11].
- Natural gas input required for both fuel cell and any NG required for boilers (if required).
- The emissions produced in the reforming process.
- Non-cooling electricity, electricity powered-cooling, water heating and space heating load shapes for several locations and commercial building types in U.S. have been collected using modeled data from National Renewable Energy Lab (Deru et. al, 2011) and stored in the model as a basis for electrical and heating demand calculations.
- The maintenance and replacement schedule for system components and parts that need to be replaced/refurbished during the system's lifetime (e.g. reformer, startup/battery and air compressor). Operation and maintenance (O&M) costs for fuel cell systems are usually correlated to the generated power by fuel system and expressed in ($/kWh). This value is calculated from the expected costs associated with replacing/refurbishing some fuel cell parts/subsystems. Note that this O&M cost is different from the scheduled annual preventive maintenance as the latter is necessary to check if the system is functioning according to expectations and typically determined by the contract between customers and fuel cell vendor (exact value depends on the size of the system). O&M cost calculations and corresponding parameters used in developing this cost component are included in Appendix F.
- Displaced boiler, water heating, or space heating equipment is not included, under the assumption that the FCS does not have 100% availability. For example, planned or unplanned outages may reduce FCS availability to 90-95% and a conventional heating is assumed to still be required for those times when the FCS is unavailable. System designs with redundant FC modules could improve overall system availability with a higher capital cost penalty, but were not included in this analysis.

[11] http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm and http://en.openei.org/wiki/Utility_Rate_Database, accessed on September 1, 2014.

Table 7.1 below summarizes key parameters used in developing use-phase model and methodology used in collecting data.

Parameter	Description
Building Types	Small hotels, hospitals, and small offices
Locations	Six different locations from different climate zones in the US were chosen for analysis. These locations are: Phoenix (AZ), San Diego (CA), Chicago (IL), Minneapolis (MN), New York City (NY), and Houston (TX)
Load Shapes	Electricity load, cooling load, space heating load and hot water load derived from NREL database for commercial building types[12]. Representative samples for 3 different days (weekday, weekend and peak-day) were tabulated for each month and then used to estimate monthly energy usages.
Fuel Cell System Size	Building dependent: • 10kWe or 50 kWe FCS for small hotels • 250kWe or 1MWe (4 x 250kW) FCS for large hospitals • 5kWe or 10kWe for small office buildings
Waste Heat Usage	Waste heat can be used for: • Space heating and hot water • Hot water only
Supplementary Energy sources	Purchased electricity from the grid if total electrical and cooling demand exceeds fuel cell capacity. Fuel-based conventional heating based conventional heating if the total space heating and water heating demand exceeds FC output at any given time.
Electricity Cost	State dependent (See Appendix F)
Installed cost	\$3900/kW for 10kW systems, \$2900/kW for 50kW systems and \$2,200/kW for 250kW systems.[13]
O&M cost	\$0.03/kWh
Scheduled maintenance cost	FC system size dependent
Natural gas price	State-specific average from 2008-2013 (See Appendix F)
FC System availability	96%
Lifetime of System	15 years

Table 7.1. Key parameters used in developing use-phase model for reformate CHP systems.

Figure 7.3 below shows the logic used in developing the use-phase model for a 50kW fuel cell system. This model has four inputs: electricity demand excluding cooling loads, electricity demand solely for space cooling using traditional electrically-driven vapor-compression air conditioners,

[12] The electricity load here refers to non-cooling load and the cooling load in kWh is split out explicitly.
[13] There is a small difference in capital costs for each system size depending on whether it is providing water heating only or both water and space heating. However, this cost delta is less than 5% of total installed costs, and the higher cost value was taken for all cases.

hot water heating demand, and space heating demand as a function of time, as recorded in daily load curves for three different days per month (weekday, weekend and peak day). These load shapes were collected from an NREL modeling simulation (Deru et al., 2011). Appendix F contains some examples of these load shapes. The operating mode of this system will follow the total electricity load (sum of 'non-cooling electricity load' and 'electricity for cooling load', so that the fuel cell system will cover all of the electrical demand at any time when total electricity demand less than or equal to 50kWe; however, if the total demand exceeds fuel cell capacity (i.e. total electricity loads >50kWe) then the system will cover the 50 kWe maximum level and the remaining will be purchased directly from the grid. Similar logic is used for heating demand.

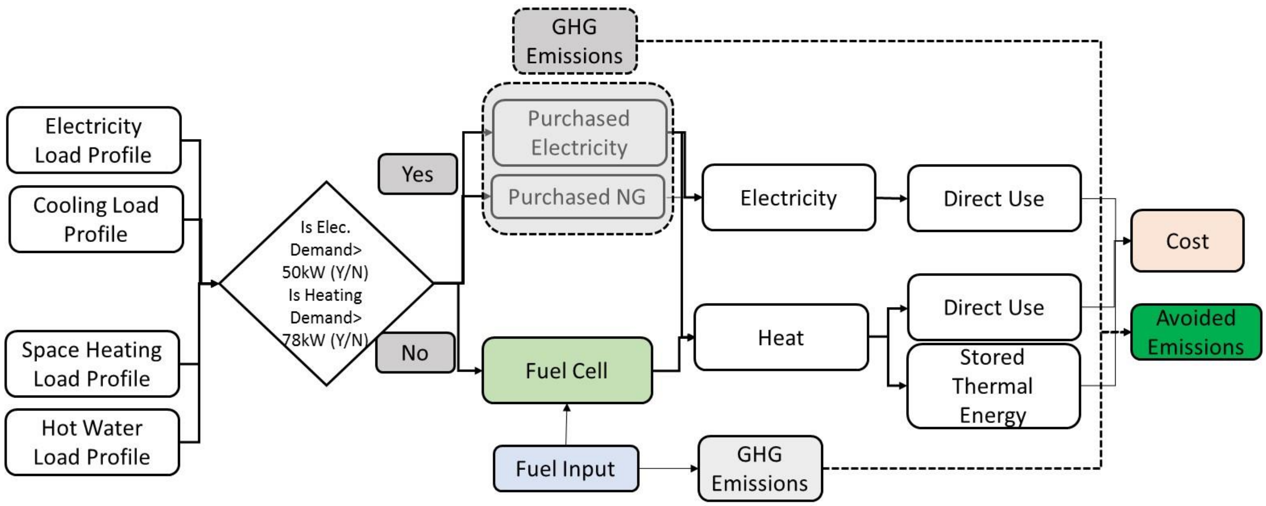


Fig. 7.3. Flow chart and logic used to model 50kW CHP system with reformate fuel.

Previous studies have analyzed the ability of a stationary LT PEM fuel cell system to thermally integrate with buildings based on the heat supply temperature from the fuel cell system, the space heating supply temperature, and the supply temperature for building service water heating systems (Colella et. al.; 2012; Colella, 2003b). For example, space heating supply temperature can be estimated as ~82°C for large U.S. office buildings using hydronic fluid loops and as ~23°C for small U.S. office buildings using air circulation loops. The supply temperature for building service water heating systems can be estimated as ~60°C for both small and large U.S. office buildings using hydronic fluid loops (Colella and Srivastava, 2012). Recent field trials of about a dozen high temperature PEM fuel cell systems installed in commercial buildings showed an average heat supply temperature from the fuel cell system to the building of ~48.4°C (Dillon and Colella, 2014). LT PEM fuel cell system supply temperatures are generally expected to be lower than HT PEM fuel cell system supply temperatures. Given the low supply temperatures of LT and HT PEM fuel cell systems, these systems may be better matched to serving space heating supply at ~23°C for small U.S. office buildings using air circulation loops and, to a lesser extent, building service water heating systems at ~60°C for U.S. office buildings using hydronic fluid loops. To evaluate different design options, this analysis considered using the fuel cell systems to supply either hot water only; or both space heating and hot water.

This initial case study analysis allows one to explore the option of integrating fuel cells into buildings (1) where the building space heating supply temperature is low enough to be served by the LT PEM fuel cell system (similar to the small U.S. commercial building case described above) and (2) where the building space heating supply temperature is clearly not enough to be served by the LT PEM fuel cell system (similar to the large U.S. commercial building case described above).

7.1.2 Results and Discussion

This section presents results from the small hotel building type in five cities (Phoenix, Houston, Minneapolis, Chicago and New York[14]). This building type has more relative heating demand than other building types and is thus expected to be more favorable for CHP. Note also that Phoenix and Minneapolis represent two extremes of the electricity grid: in Phoenix there is a relatively low carbon intensity and Minneapolis has a relatively high carbon intensity with more coal power in the grid mix.

Key assumptions and model outputs for the small hotel sector are summarized in Tables 7.2-7.6. A CHP system in general achieves higher efficiency if there is a high utilization of both electrical and heat output of the system. In commercial buildings, the heating load is typically lower than the electrical load and higher overall system efficiency can be obtained by sizing the system to accommodate the heating load. However, from the previous chapter we have seen that smaller sized systems have higher installed costs in $/kW. A range of fuel cell sizes is chosen to explore the tradeoffs between FC capital cost and overall efficiency. FCS sizes were taken to be 10kW or 50 kW for small hotels and use-phase costs and total cost analysis is described below. The hospital and small office building cases are included in Appendix F.

Parameter	Phoenix, AZ	Minneapolis, MN	Chicago, IL	NYC, NY	Houston, TX	Unit
Building Type	**Small Hotel**					
FC System Size	**10, 50**					kW
FC Power Utilization (10kW)	100%	100%	100%	100%	100%	%
FC Power Utilization (50kW)	90.9%	82.1%	82.2%	74.9%	86.2%	%
FC Heat Utilization space and water heating; water heating only[15] (10kW)	77.4%; 59.4%	100%; 98.2%	100%; 91.9%	100%; 89.6%	64.1%; 64.1%	%
FC Heat Utilization space and water heating; water heating only (50kW)	15.3%; 11.7%	46.0%; 19.4%	38.9%; 18.15%	38.4%; 17.7%	12.7%; 12.7%	%
Displaced Electricity by FC (10kW)	84,096	84,096	84,096	84,096	84,096	kWh/yr
Heat produced by FC (10kW)	124,409	124,409	124,409	124,409	124,409	kWh/yr
Displaced Electricity by FC (50kW)	382,253	345,368	345,791	314,930	362,313	kWh/yr

[14] Buildings in California were taken from a separate database (CEUS) that the non-California cities and did not include the small hotel building type. The California database includes other building types studied here such as hospitals and small offices.
[15] Note that "FC Heat Utilization" is relative to the thermal efficiency of the CHP system given in Table 2.3. 100% FC heat utilization means that the full thermal efficiency of the system is realized.

Heat produced by FC (50kW)	565,468	501,840	502,765	454,903	532,839	kWh/yr
Max. space heating displaced by FC	23,307	174,743	135,869	135,869	0	kWh/yr
Max. water heating displaced by FC	76,954	127,112	118,971	116,075	83,071	kWh/yr
Capital costs of FC including installation cost	3,900 for 10kW 2,900 for 50kW					$/kW
Electricity price	Variable by time	Variable by time	Variable by time	Variable by time	Variable by time	$/kWh
Demand Charge ($ / Peak kW per month)	4.05	3.30	5.69	17.95	12.39	$/kW
NG cost	0.0357	0.0258	0.0292	0.0331	0.0263	$/kWh
Scheduled maintenance cost ‡	1,000	1,000	1,000	1,000	1,000	$/yr
O&M cost	0.030	0.030	0.030	0.030	0.030	$/kWh
FC system availability‡‡	96%	96%	96%	96%	96%	%
Lifetime of system	15	15	15	15	15	Yr
Interest rate	5%	5%	5%	5%	5%	%

‡ From CETEEM model (Lipman et al., 2004).
‡‡ In this analysis the CHP system was assumed to have a 96% availability factor and three outages during the year. One outage is assumed to be a planned maintenance outage and two are assumed to be unplanned forced outages.

Table. 7.2. Assumptions for cost and environmental impact model for small hotel case.

As shown in previous studies, in general, as the in-use heat utilization increases, the economics and positive environmental impacts of CHP fuel cell systems also rise (Colella et al., 2010). For the small hotel case, as shown in Table 7.2, the overall heat recovery varies from 60-100% for the 10kW case to only 10-40% in the 50kW case, relative to the maximum technically feasible level.

As shown in the tables below, in general the fuel cell cases have considerable additional costs compared to the conventional alternative. However, for the FCS supplying both water heating and space heating the, overall cost of the FC case is within 10% of the No FC case in (a) Minneapolis at 50kW system size and (b) Minneapolis, Phoenix and Chicago for the 10kW case (Tables 7.3 and 7.5). For a FCS supplying water heating only, Minneapolis and Chicago are within 10% of the No FC Case for the 10kW system size only (Tables 7.4 and 7.6). This indicates that there may be a niche application for FCS for small hotels in Minneapolis due to a favorable spark spread and sufficient heating demand.[16]

[16] Spark spread is defined as follows: SS = Price of Electricity - [(Price of Gas) * (Heat Rate)] = $/MWh - [($/MMBtu) * (MMBtu / MWh)], or equivalently, the theoretical gross margin of a gas-fired power plant from selling a unit of electricity. Heat rate is often taken as 2.0 by convention for gas-fired plants. CHP systems powered by natural gas are more economically favorable in regions with large spark spread.

Output results from use-phase model for small hotel (50 kW FC system)										
Output	Phoenix, AZ		Minneapolis,		Chicago, IL		NYC, NY		Houston, TX	
	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell
FC System Utilization		90.9%		82.1%		82.2%		74.9%		86.2%
Total Electricity Demand (kWh/yr)	576,668		419,590		424,147		369,661		497,656	
Total Space Heating Demand (kWh/yr)	23,307		174,743		135,869		135,869		0	
Total Water Heating Demand (kWh/yr)	76,954		127,112		118,971		116,075		83,071	
Annual Generated Power by FC (kWh/yr)		382253		345368		345791		314930		362313
Annual Generated Heat by FC (kWh/yr)		565468		501840		502765		454903		532839
Capital Cost ($/yr)		13970		13970		13970		13970		13970
O&M Cost ($/yr)		11468		10361		10374		9448		10869
Scheduled Maintenance ($/yr)		1000		1000		1000		1000		1000
Fuel Cost- FCS only ($/yr)		42227		27285		30998		31885		29421
Residual Fuel ($/yr)	3574	0	7780	84	7450	9	8351	9	2185	0
Electricity Energy Cost ($/yr)	47305	15360	45374	6679	32104	4889	8798	990	15427	3728
Electricity Demand Charge ($/kWh)	5445	3635	3422	1937	6021	3460	16959	8882	15490	9422
Monthly Charge	150	150	131	131	348	348	1241	1241	295	295
Total Cost ($/yr) FC supplies both space heating and Hot water	56473	87809	56707	61447	45923	65047	35349	67424	33397	68706

Table 7.3. Output results from use-phase model for small hotel (50 kW FC system) with FCS providing water heating and space heating.

Output results from use-phase model for small hotel (50 kW FC system)										
Output	**Phoenix, AZ**		**Minneapolis,**		**Chicago, IL**		**NYC, NY**		**Houston, TX**	
	No Fuel Cell	**Fuel Cell**	**No Fuel Cell**	**Fuel Cell**	**No Fuel Cell**	**Fuel Cell**	**No Fuel Cell**	**Fuel Cell**	**No Fuel Cell**	**Fuel Cell**
FC System Utilization		90.9%		82.1%		82.2%		74.9%		86.2%
Total Electricity Demand (kWh/yr)	576,668		419,590		424,147		369,661		497,656	
Total Space Heating Demand (kWh/yr)	23,307		174,743		135,869		135,869		0	
Total Water Heating Demand (kWh/yr)	76,954		127,112		118,971		116,075		83,071	
Annual Generated Power by FC (kWh/yr)		382253		345368		345791		314930		362313
Annual Generated Heat by FC (kWh/yr)		565468		501840		502765		454903		532839
Capital Cost ($/yr)		13970		13970		13970		13970		13970
O&M Cost ($/yr)		11468		10361		10374		9448		10869
Scheduled Maintenance ($/yr)		1000		1000		1000		1000		1000
Fuel Cost- FCS only ($/yr)		42227		27285		30998		31885		29421
Residual Fuel ($/yr)	3574	831	7780	4504	7450	3972	8351	4504	2185	0
Electricity Energy Cost ($/yr)	47305	15360	45374	6679	32104	4889	8798	990	15427	3728
Electricity Demand Charge ($/kWh)	5445	3635	3422	1937	6021	3460	16959	8882	15490	9422
Electricity Fixed Monthly Charge ($/yr)	150	150	131	131	348	348	1241	1241	295	295
Total Cost ($/yr) FC supplies Hot water only	56473	88640	56707	65867	45923	69010	35349	71919	33397	68706

Table 7.4. Output results from use-phase model for small hotel (50 kW FC system) with FCS providing water heating only.

Output results from use-phase model for small hotel (10 kW FC system)										
Output	**Phoenix, AZ**		**Minneapolis,**		**Chicago, IL**		**NYC, NY**		**Houston, TX**	
	No Fuel Cell	**Fuel Cell**	**No Fuel Cell**	**Fuel Cell**	**No Fuel Cell**	**Fuel Cell**	**No Fuel Cell**	**Fuel Cell**	**No Fuel Cell**	**Fuel Cell**
FC System Utilization		100%		100%		100%		100%		100%
Total Electricity Demand (kWh/yr)	576668		419590		424147		369661		497656	
Total Space Heating Demand (kWh/yr)	23,307		174,743		135,869		135,869		0	
Total Water Heating Demand (kWh/yr)	76,954		127,112		118,971		116,075		83071	
Annual Generated Power by FC (kWh)		84,096		84,096		84,096		84,096		84,096
Annual Generated Heat by FC (kWh)		124,409		124,409		124,409		124,409		124,409
Capital Cost ($/yr)		3,757		3,757		3,757		3,757		3,757
O&M Cost ($/yr)		2523		2523		2523		2523		2523
Scheduled Maintenance ($/yr)		500		500		500		500		500
Fuel Cost- FCS only ($/yr)		8994		6501		7374		8363		6635
Residual Fuel ($/yr)	3574	554	7780	4698	7450	4000	8351	4452	2185	211
Electricity Energy Cost ($/yr)	47305	40333	45374	35998	32104	25495	8798	6713	15427	12712
Electricity Demand Charge ($/kWh)	5445	5093	3422	3125	6021	5508	16959	15344	15490	14321
Electricity Fixed Monthly Charge ($/yr)	150	150	131	131	348	348	1241	1241	295	295
FC supplies both space heating and Hot water	56473	61904	56707	57233	45923	49506	35349	42893	33397	40954

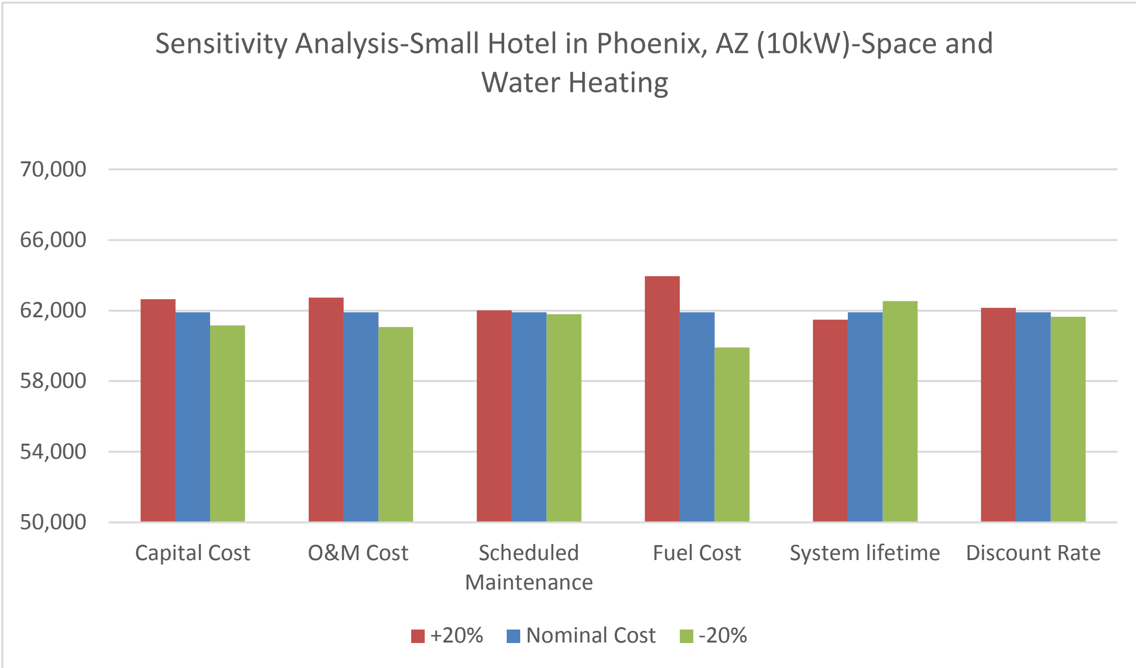
Table 7.5. Output results from use-phase model for small hotel (10 kW FC system) with FCS providing water heating and space heating.

Output results from use-phase model for small hotel (10 kW FC system)										
Output	Phoenix, AZ		Minneapolis,		Chicago, IL		NYC, NY		Houston, TX	
	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell
FC System Utilization		100%		100%		100%		100%		100%
Total Electricity Demand (kWh/yr)	576668		419590		424147		369661		497656	
Total Space Heating Demand (kWh/yr)	23,307		174,743		135,869		135,869		0	
Total Water Heating Demand (kWh/yr)	76,954		127,112		118,971		116,075		83071	
Annual Generated Power by FC (kWh)		84,096		84,096		84,096		84,096		84,096
Annual Generated Heat by FC (kWh)		124,409		124,409		124,409		124,409		124,409
Capital Cost ($/yr)		3757		3757		3757		3757		3757
O&M Cost ($/yr)		2523		2523		2523		2523		2523
Scheduled Maintenance ($/yr)		500		500		500		500		500
Fuel Cost- FCS only ($/yr)		8994		6501		7374		8363		6635
Residual Fuel ($/yr)	3574	1068	7780	5344	7450	4777	8351	5353	2185	211
Electricity Energy Cost ($/yr)	47305	40333	45374	35998	32104	25495	8798	6713	15427	12712
Electricity Demand Charge ($/kWh)	5445	5093	3422	3125	6021	5508	16959	15344	15490	14321
Electricity Fixed Monthly Charge ($/yr)	150	150	131	131	348	348	1241	1241	295	295
Cost ($/yr) FC supplies Hot water only	56473	62419	56707	57880	45923	50283	35349	43794	33397	40954

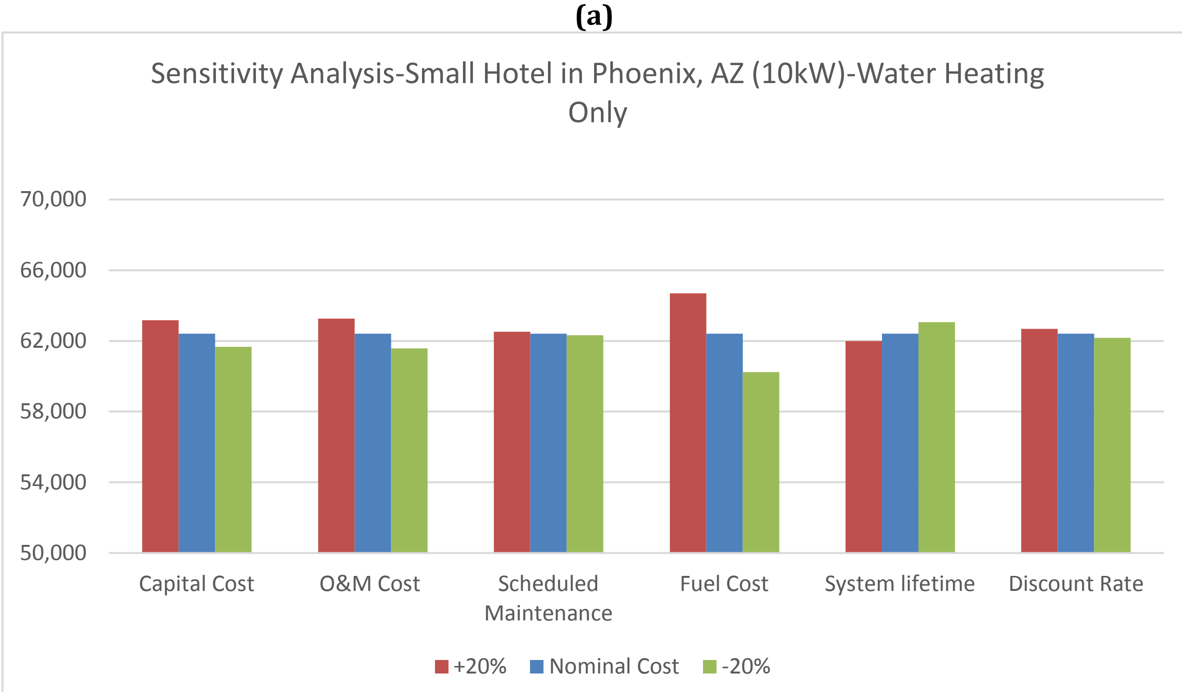
Table 7.6. Output results from use-phase model for small hotel (10 kW FC system) with FCS providing water heating only.

7.1.3. Sensitivity analysis for use phase

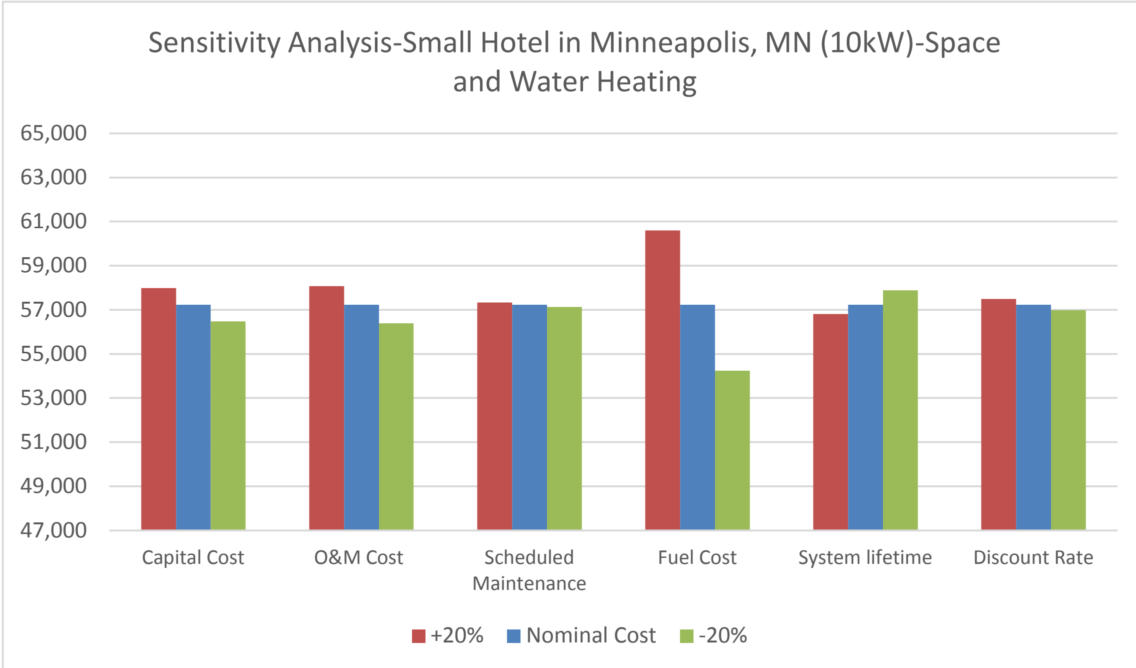
Sensitivity analysis for use phase model was done for a 10 kW fuel cell system used in small hotels in Phoenix and Minneapolis. This section focuses on the cost analysis while next section will focus on emissions assciated with the use phase. The impact on the annual cost in ($) is calculated for a ±20% change in the sensitivity parameter being varied (Fig. 7.4).


Sensitivity Analysis-Small Hotel in Phoenix, AZ (10kW)-Space and Water Heating
70,000
66,000
62,000
58,000
54,000
50,000
Capital Cost
O&M Cost
Scheduled Maintenance
Fuel Cost
System lifetime
Discount Rate
+20%
Nominal Cost
-20%

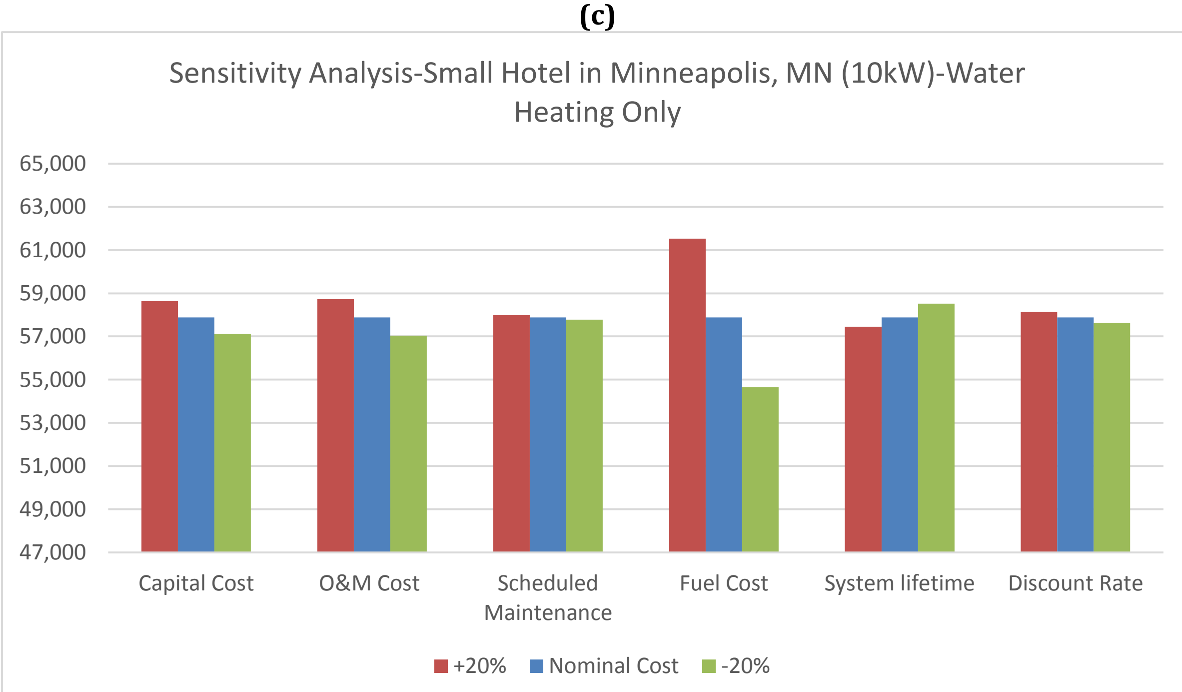
(a)


Sensitivity Analysis-Small Hotel in Phoenix, AZ (10kW)-Water Heating Only
70,000
66,000
62,000
58,000
54,000
50,000
Capital Cost
O&M Cost
Scheduled Maintenance
Fuel Cost
System lifetime
Discount Rate
+20%
Nominal Cost
-20%

(b)



(c)



(d)

Figure 7.4. Sensitivity analysis for the 10kW fuel cell case installed in small hotel in Phoenix and Minneapolis centered around total annual cost. (a) Waste heat from the fuel cell system is utilized for space and water heating (Phoenix); (b) waste heat from the fuel cell system is utilized for water heating only (Phoenix); (c) waste heat from the fuel cell system is utilized for space and water heating (Minneapolis); (d) waste heat from the fuel cell system is utilized for water heating only (Minneapolis). (Note: the following O&M cost values have been utilized: 3₵/kWh for nominal case; 2₵/kWh for lower bound; 4₵/kWh for upper bound).

As can be seen from these charts, fuel costs have the highest cost senstivity within the range examined, followed by capital and O&M costs. The variability in assumed discount rate and scheduled maintanance have lower impact within the +/- 20% range of input values examined.

7.1.4 Conclusions for Use-Phase Model

Overall LCA analysis showed that the fuel cell CHP system use-phase has a high environmental impact relative to the other LCA phases and is responsible for 90% of the fuel cell system life cycle's total environmental impact. This is mainly due to the emissions caused by the steam reforming process with natural gas as a fuel input. Since the 'use and maintenance' phase accounts for a major portion of environmental impact of fuel cell systems, a realistic use-phase model was developed which can analyze energy, and overall costs for several commercial buildings. This model takes modeled load shapes for a given building and calculates generated power (electricity and heat), and FCS capital, operational, and fuel costs.

The use-phase model shows that adopting a FC system as an alternative energy system can be a cost competitive power source in some building types and locations (e.g., small hotels in Minneapolis) where the spark spread is relatively high.

In the next section, the environmental impacts of fuel cell systems in different locations across the U.S. are explored. Although the cost of having the FCS is higher than the case of no fuel cell, we will see that adopting CHP fuel cell systems in some areas in the U.S. (e.g., Chicago) can save a large amount of GHG emissions where grid electricity has high carbon intensity due to a relatively large fraction of coal-based electricity.

7.2 Life Cycle Impact Assessment Modeling (LCIA)

7.2.1 General Approach of LCIA

For the LCIA project element we developed a model to quantify the environmental and human health impacts and/or benefits attributable to the use of fuel cell systems in commercial buildings. The model provides spatial resolution at the state level for electricity generation impacts and at the county level for on-site fuel consumption. The motivation for the development and application of this model is the need to assess the cost of health and environmental externalities associated with fuel cells. The use of fuel cells can impose impacts that arise from the manufacturing of the cells, the extraction of raw materials for manufacturing, fuel cell operation, and the production of energy for manufacturing, transportation, and servicing of the cell. However, the use of fuel cells will also offset the production of electricity in the region where the cells supply power. This offset can have health benefits that will depend on the sources of electricity in a region and the impacts associated with that electricity production.

The approach is the following. A fuel cell system in a given building displaces some fraction of building electricity demand that otherwise would be purchased from the grid and some fraction of heating demand fuel, as specified by the user of the model. Valuation of health and environmental externalities for grid-based electricity and onsite fuel consumption are calculated according to the inputs in Table 7.7 below. Externality valuation in $/MWhe or $/MWh(thermal energy) for a particular pollutant are the product of the marginal emission factor (MEF) in tons/MWh and the marginal benefit of abatement (MBA) in $/ton. As noted in the table, displaced emissions from the electricity grid are assumed to be emitted from a smokestack (or "stack-height level") and displaced emissions from onsite fuel are assumed to be emitted at ground level. For electricity-production emissions, we utilize MEFs from Siler-Evans et al. (2012) at the NERC region-level and MBA estimates at the state level based on an earlier study by Muller and Mendelsohn (2007), while for onsite fuel, MEFs utilize EPA values and MBA estimates are again taken from Muller and Mendelsohn (2007) at the county level.

This approach provides a greater degree of spatial resolution compared to taking national averages for MBA values and a comparison of this treatment versus the use of national averages will be addressed in future work. Further work can also model more localized MEFs for the electricity system, coupled with finer resolution for MBA values. At the temporal level, this work also utilizes MEF factors at the monthly level for electricity and MBA factors at the annual level. Further work could explore providing a greater degree of temporal resolution for both of these factors, but is beyond the scope of this study.

We utilize commercial building surveys to estimate the mix of heating fuel types by region that is displaced by the FCS. Externalities to be valued include morbidity, mortality, impaired visibility, recreational disruptions, material damages, agricultural and timber damages, and global warming. Details for computing average electricity intensity and the mix of heating fuel types by region are described in Appendix F.

Type	Item	Units	Assumed source of emissions	Spatial Regime	Temporal Regime	Reference
Electricity	MEF	Tons/MWh	Stack-height level	NERC Regions[17]	Monthly	Siler-Evans (2012)
Electricity	MBA	$/Ton		State level	Annual	Muller and Mendelsohn (2007)
Fuel	MEF	Tons/MWh	Ground level	Site level	Annual	EPA, Various
Fuel	MBA	$/Ton		County level	Annual	Muller and Mendelsohn (2007)

Table 7.7. Inputs for the calculation of externality valuations for grid-purchased electricity and for onsite fuel consumption. Tons here refers to the quantity of a particular pollutant such as SO_2. Damages from a marginal unit of electricity or fuel is the product of MEF and MBA. (MEF = marginal emission factor; MBA = marginal benefit of abatement).

Electricity and Fuel Emission Factors
In our model, stationary fuel cells provide electricity and heat to commercial buildings in different cities in the United States. Electricity from fuel cells displaces energy and emissions from local electricity grids, comprised of conventional and renewable generators. Over long periods of time (on the order of decades), a large reduction in demand for grid electricity may lead to the retirement of conventional generators. In this study, we only consider short-term displacement and measure this displacement using regional marginal emission factors. Marginal emission factors (MEFs) express the avoided carbon dioxide ($CO_{2\text{-equivalent}}$), sulfur dioxide (SO_2), and nitrogen oxides (NOx), emissions from displaced marginal generators. It is difficult to know exactly which

[17] See http://www.nerc.com/AboutNERC/keyplayers/Pages/Regional-Entities.aspx for a map of the eight NERC regions in North America.

generators are operating at the margin, but the set of generators that will be deployed to meet electricity demand during high demand periods (commonly called peaker plants) can be estimated using dispatch models and historical regressions.

Peaker plants are typically the most expensive or dirtiest plants to operate, such as natural gas-turbines and older coal- and natural gas-fired power plants. Siler-Evans et al. (2012) developed a method for calculating MEFs for eight North American Electric Reliability Corporation (NERC) regions in the United States using historical data from the EPA Continuous Emissions Monitoring System (CEMS). CEMS provides hourly data on CO_2, SO_2, and NOx emissions up to the year 2011 from fossil-fueled generators with a nameplate capacity greater than or equal to 25 MW. This method was applied in a separate study quantifying the displaced emissions from wind and solar adoption in Emissions and Generation Resource Integrated Database (eGRID) sub-regions (Siler-Evans et al. 2013). These regions are on the same spatial scale as power control areas, which estimate the control area over which power plants provide energy to consumers.

The approach here is to use MEFs for greenhouse gases GHG (CO_2, CH_4, and N_2O), NOx, and SOx. We did not find MEFs for direct particulate matter emissions (PM10 and PM2.5). A significant fraction of PM from electricity generation comes from reactions of SOx and NOx in the atmosphere. These emissions are challenging to estimate but can be included to an increasing degree with better modeling techniques and capabilities as described below. The PM emission values shown below are approximations, to be refined as more data are obtained on especially the marginal PM2.5 and PM10 emissions from electricity generation.

Regional MEFs for grid-based electricity are shown in Table 7.8. MEFs for onsite combusted fuels are also shown (EIA, 2011 and 2013) and further discussed in Appendix F. Commercial building surveys were utilized to estimate the mix of heating fuel types by region that is displaced by the FCS. Results of this analysis are shown in Figures 7.5 and 7.6. Details of this analysis are provided in Appendix F.

	tCO_2/kWh	tCH_4/kWh	tN_2O/kWh	tNO_x/kWh	tSO_x/kWh	*tPM_{10}/kWh*	*$tPM_{2.5}$/kWh*
Electricity (Chicago)	7.31E-04			9.4E-07	3.3E-06		
Electricity, (Houston)	5.27E-04			3.2E-07	4.0E-07		
Electricity (Minneapolis)	8.34E-04			1.09E-06	2.11E-06		
Electricity (New York City)	4.89E-04			3.2E-07	5.5E-07		
Electricity (Phoenix)	4.86E-04			3.2E-07	1.80E-07		
Electricity (San Diego)	4.86E-04			3.2E-07	1.80E-07		
Natural Gas	1.81E-04	1.71E-08	3.41E-10	1.51E-07	9.21E-10	*1.16E-08*	
Fuel Oil	2.50E-04	1.02E-08	2.05E-09	3.44E-07	1.73E-06	*8.88E-08*	*4.98E-08*
Propane	2.10E-04	6.82E-12	3.41E-10				

Table 7.8: Regional marginal emission factors for electricity and emission factors for heating fuels. CO_2 represents CO_2 equivalents if values for CH_4 and N_2O are not listed. (Note that kWh are used as heating fuel units here for natural gas, fuel oil and propane).

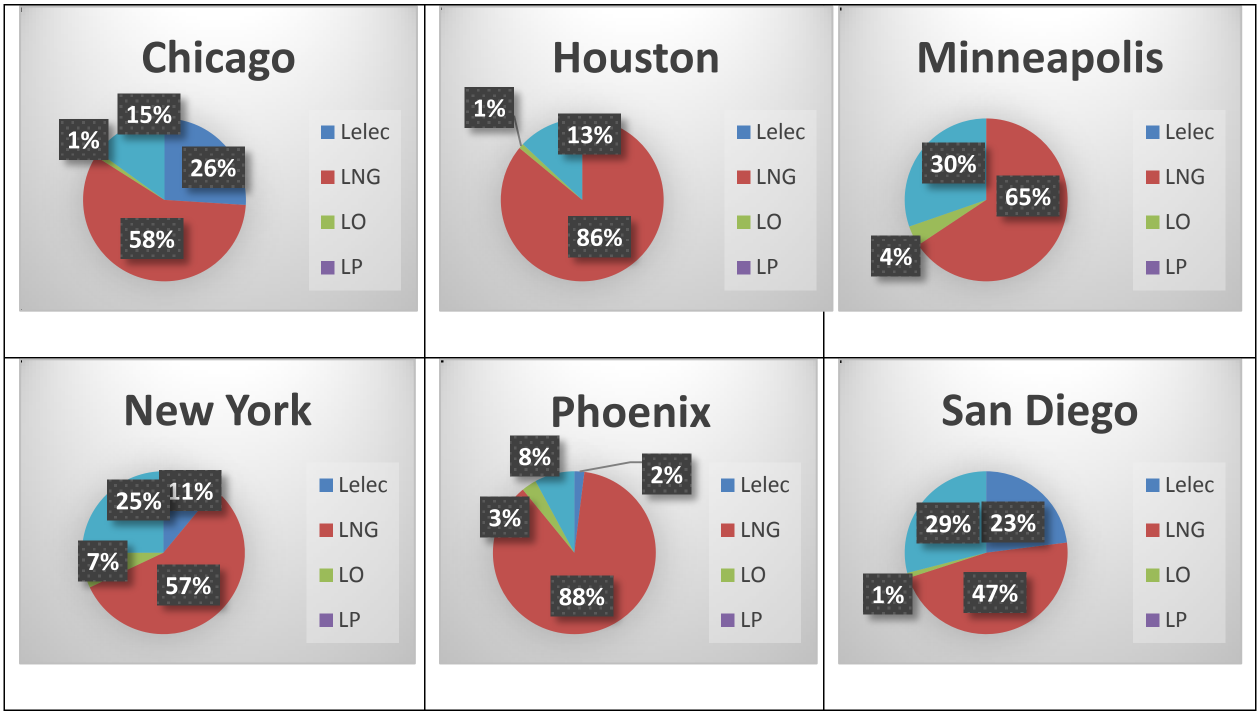


Fig. 7.5. The representative fraction of heat provided by electricity (elec), natural gas (ng), fuel oil (o), propane (p), and district heating (dh) in large hospitals. In this analysis the same fraction is used for both water heating and space heating.

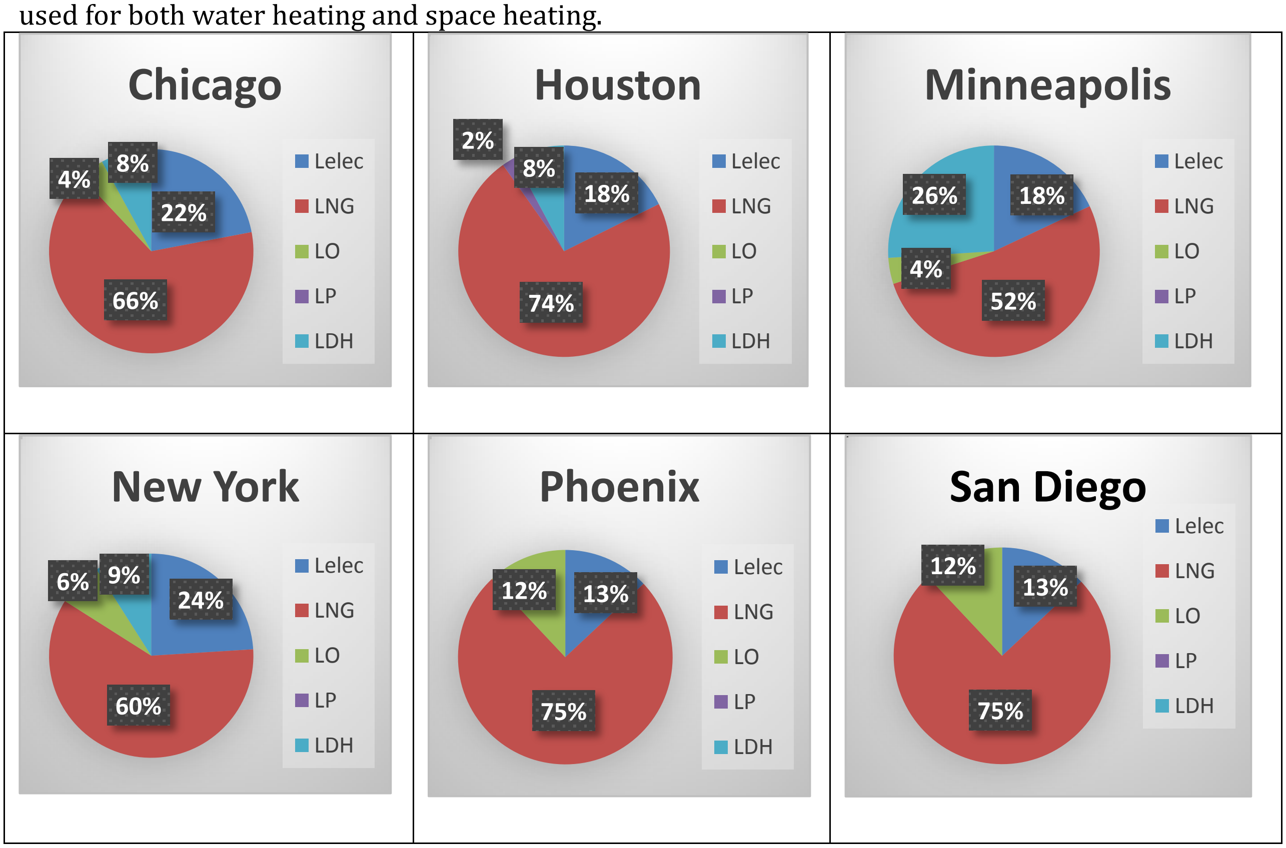


Fig. 7.6. The representative fraction of heat provided by electricity (elec), natural gas (ng), fuel oil (o), propane (p), and district heating (dh) in small hotel. In this analysis the same fraction is used for both water heating and space heating.

APEEP Damage Factors

The benefit of reducing emissions through FCS adoption can be monetized using conversion factors that express marginal benefit of abatement. These factors estimate the damage that a unit of emitted pollutant will cause if released in a specific location, thus explaining their alternative name “damage factors”.

In this work, we choose a set of damage factors described and applied in the Air Pollution Emission Experiments and Policy Analysis Model (APEEP). Alternatively other studies could be used for damage factors and will be added for sensitivity analysis in future work.

APEEP monetizes human health and environmental damages associated with SO_2, volatile organic compounds (VOC), NO_X, ammonia (NH_3), fine particulate $PM_{2.5}$, and coarse particulate PM_{10} emissions from power plants[18] (Muller and Mendelsohn 2007). This integrated assessment calculated a baseline level of damage using pollution levels in 2002. Using APEEP, we introduced one additional metric ton of pollutant from a specific source and determined the change in national damages. This process was repeated for each pollutant at about 10,000 sources, generating a set of marginal damages that are more reliable than an approach based on national averages of damages. In this process, atmospheric chemistry models and air -transport models were used to estimate downwind primary and secondary pollution doses.

For example, SO_2 forms $PM_{2.5}$ (sulfate), and NO is converted to NO_2, which reacts with VOC to form ozone (O_3) and $PM_{2.5}$ (nitrate). Once the emissions and the resulting pollutants are calculated, human exposures are estimated from a database of county-level receptor populations (humans, materials, crops, timber etc.). Damage factors were calculated for “ground level”: (less than 250 meters off the ground), “medium high” (<500 m), and “tall-smoke stack” sources (>500 m). Concentration-response models are used to convert exposure to physical responses such as morbidity, mortality, visibility impairment, reduced recreation, lower agricultural and timber yields, and material degradation. Finally, economic models convert these physical responses to dollar values. In this study, we assumed the value of a statistical life to be $6 million and use a discount rate of three percent (Muller and Mendelsohn 2007). The implication of these values is that morbidity and mortality are valued more when they occur in younger people than in older people. The total damage from a pollutant emission from a given source is estimated by multiplying the pollutant damage factor with the mass of emitted pollutant.

Marginal benefit of abatement or damage factors are shown in Tables 7.9 and 7.10 for ground level and stack-height level emissions, respectively, for the six regions of the U.S. studied here.

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[18] The subscript on PM indicates the greatest particle diameter in micrometers that is captured in the particle measurement.

City	County	State	Ammonia	Nitrogen Oxides	Sulfur Dioxide	Volatile Organic Compounds	Particulate Matter	Particulate Matter
			$/ton NH_3	$/ton NO_x	$/ton SO_2	$/ton VOC	$/ton $PM_{2.5}$	$/ton PM_{10}
Chicago	Cook	IL	563438	1276	15867	12168	116779	17067
Houston	Harris	TX	9020	6076	19750	4542	44673	5286
Minneapolis	Hennepin	MN	45731	11455	21055	5547	48195	12818
New York	New York	NY	51193	9448	45595	20343	195469	28300
Phoenix	Maricopa	AZ	3676	3889	7416	1927	18400	2797
San Diego	San Diego	CA	90776	328	55254	7323	68162	12392

Table 7.9. Marginal benefit of abatement for ground level emissions in dollars per metric ton for the six counties in this study (in 2014 dollars). Statistical life value of $6 million is assumed. Muller and Mendelsohn (2007)

State	Ammonia	Nitrogen Oxides	Sulfur Dioxide	Volatile Organic Compounds	Particulate Matter	Particulate Matter
	$/ton NH3	$/ton NOx	$/ton SO_2	$/ton VOC	$/ton $PM_{2.5}$	$/ton PM_{10}
Arizona	1531	1127	2781	334	3463	469
California	10068	747	6167	1014	10776	1689
Illinois	16114	2382	6879	1190	11785	1213
Minnesota	2832	2280	6308	717	6963	853
New York	12315	981	7150	1868	19838	2024
Texas	1274	1659	2763	472	4843	594

Table 7.10. Marginal benefit of abatement for stack height level-emissions in dollars per ton (in 2014 dollars) for the six states in this study. (Points sources with height >250 m and <500 m and statistical life value of $6 million). Muller and Mendelsohn (2007)

Emissions from Fuel Cells

Direct EFs reported in recent literature on fuel cells allowed us to determine reasonable EF for CO_2, CH_4, N_2O, CO, NO_X, SO_X, PM_{10} and VOC (Table 7.11). All values are from Colella 2012 or are derived from this reference. Direct EFs reported in recent literature on fuel cells allowed us to determine reasonable estimates of EFs for CO_2, CH_4, N_2O, CO, NO_X, SO_X, PM_{10} and VOC (Table 7.11). All values are from Colella 2012 or are derived from results reported elsewhere in this report.

Pollutant	Emissions in tons/kWhe
CO_2	5.43E-04
NO_x	7.5-09
SO_x	negligible
PM_{10}	negligible
VOC	negligible
CH_4	5.6E-07
CO	1.9E-08
N_2O	6.5E-08

Table 7.11. Fuel cell emission factors in metric tons per kWh for a LT PEM FC CHP system with reformate and natural gas fuel input (based on Colella 2012).

Fuel cell emissions were modeled as ground level emissions and were converted to damages using APEEP county ground level damage factors. CO_2, CH_4, and N_2O were converted to CO_2eq using 100 year GWP factors of 1, 21, and 310, respectively[19].

The total masses of emissions emitted from the fuel cell over a year were calculated by multiplying each EF by the power (P) provided by the fuel cell in our scenarios. Emissions from the fuel cell were modeled as ground level emissions and were converted to damages using APEEP county-specific ground level conversion factors shown in Table 7.11. CO_2, CH_4, and N_2O were converted to GWP using characterization factors of 1, 21, and 310, respectively.
Greenhouse gas emissions were converted to CO_2eq using a 100 year global warming potential and monetized by assuming a social cost of carbon (SCC), of \$44/tCO_2eq. Values for the social cost of carbon have been compiled by the Interagency Working Group on Social Cost of Carbon (White House 2013), for use in regulatory analysis. As a base value for additional examination we use an intermediate value of \$37/tCO_2 (\$2007) and adjusted for inflation to get ~\$44/tCO_2 as an approximate value of the current social cost of carbon.

A detailed description of the calculation of displaced emissions for grid based electricity and onsite fuel is provided in Appendix F.

7.2.5 LCIA Results

Environmental and human health impacts (or benefits) from the adoption of FCS vary widely among locations due to differences in building and fuel cell operation, nearby population, and regional conditions affecting the transport and transformation of pollutants. The amount of power and heat provided by a FCS to hospitals and small hotels were determined based on building- and city-specific load shapes as discussed in the previous sections. A pollutant emitted in an urban environment is likely to result in higher damages than if it was emitted in a rural environment. Thus, the monetized value of mitigating pollution emissions is typically higher when city-specific data is used as opposed to national average data. Tables 7.12-7.15 below summarize the per building impacts of utilizing a fuel cell CHP system in small hotels in five U.S. cities.

19 http://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html, accessed September 25, 2009.

For small hotels with a 50kW FC system, Minneapolis and Chicago realize the largest GHG savings (Tables 7.12 and 7.13). These two Midwestern cities have about three to five cents per kWhe savings from reduced externalities. Phoenix has greater emissions with the FCS than without it since the carbon intensity for its grid electricity (Table 7.8) is assumed to be lower than that for a reformer-based FCS (Table 7.11).

LCIA Results for small hotel (50 kW FC system) – Water and Space Heating					
Output	**Phoenix**	**Minneapolis**	**Chicago**	**New York City**	**Houston**
Annual Generated Power by FC (kWh)	382,253	345,368	345,791	314,930	362,313
Annual Generated Heat by FC (kWh)	565,468	501,840	502,765	454,903	532,839
Avoided GHG [tCO2e/y]	-11.0	167.3	127.8	17.4	2.3
Avoided NOx [tNOx/y]	0.142	0.465	0.406	0.135	0.125
Avoided SOx [tSOx/y]	0.092	0.865	1.339	0.232	0.145
Avoided PM10 [t/y]	*0.0019*	*0.0028*	*0.0029*	*0.0022*	*0.00071*
Avoided PM2.5 [t/y]	*0.00059*	*0.00053*	*0.00053*	*0.00078*	*0.0000*
GHG credit at $44/ton CO2 ($/kWhe)	-0.0013	0.021	0.016	0.002	0.0003
Health, Environmental Savings ($/kWhe)	0.0015	0.020	0.030	0.010	0.0018

Table.7.12. Monetized marginal environmental and human health impacts of FCS operation scenarios for a 50kW FC system in a small hotel compared to grid-based electricity and conventional heating. The FCS system is assumed to offset water heating and space heating.

LCIA Results for small hotel (50 kW FC system) – Water Heating Only					
Output	**Phoenix**	**Minneapolis**	**Chicago**	**New York City**	**Houston**
Annual Generated Power by FC (kWh)	382,253	345,368	345,791	314,930	362,313
Annual Generated Heat by FC (kWh)	565,468	501,840	502,765	454,903	532,839
Avoided GHG [tCO2e/y]	-16.3	122.3	88.5	1.4	2.3
Avoided NOx [tNOx/y]	0.137	0.414	0.363	0.123	0.125
Avoided SOx [tSOx/y]	0.086	0.786	1.232	0.202	0.145
Avoided PM10 [t/y]	*0.0015*	*0.0012*	*0.0014*	*0.0015*	*0.00071*
Avoided PM2.5 [t/y]	*0.00045*	*0.00022*	*0.00025*	*0.00039*	*0.0000*
GHG credit at $44/ton CO_2 ($/kWhe)	-0.0019	0.016	0.011	0.000	0.0003
Health, Environmental Savings ($/kWhe)	0.0013	0.018	0.027	0.007	0.0018

Table.7.13. Monetized marginal environmental and human health impacts of FCS operation scenarios for a 50kW FC system in a small hotel compared to grid-based electricity and conventional heating. The FCS system is assumed to only offset water heating.

For the 10kW fuel cell system, more waste heat is utilized and the GHG savings is positive for all five cities. Minneapolis and Chicago in this case realize about five to seven cents per kWhe savings from externalities (Tables 7.14 and 7.15).

LCIA Results for small hotel (10 kW FC system) – Water and Space Heating					
Output	**Phoenix**	**Minneapolis**	**Chicago**	**New York City**	**Houston**
Annual Generated Power by FC (kWh)	84,096	84,096	84,096	84,096	84,096
Annual Generated Heat by FC (kWh)	124,409	124,409	124,409	124,409	124,409
Avoided GHG [tCO2e/y]	15.6	53.8	49.3	22.4	14.9
Avoided NOx [tNOx/y]	0.047	0.128	0.119	0.050	0.041
Avoided SOx [tSOx/y]	0.038	0.233	0.375	0.077	0.040
Avoided PM10 [t/y]	*0.0019*	*0.0011*	*0.0014*	*0.0016*	*0.00071*
Avoided PM2.5 [t/y]	*0.00059*	*0.00022*	*0.00026*	*0.00042*	*0.0000*
GHG credit at $44/ton CO2 ($/kWhe)	0.0081	0.028	0.026	0.012	0.0078
Health, Environmental Savings ($/kWhe)	0.0037	0.024	0.035	0.017	0.0026

Table.7.14. Monetized marginal environmental and human health impacts of FCS operation scenarios for a 10kW FC system in a small hotel compared to grid-based electricity and conventional heating. The FCS system is assumed to offset water heating and space heating.

LCIA Results for small hotel (10 kW FC system) – Water Heating Only					
Output	**Phoenix**	**Minneapolis**	**Chicago**	**New York City**	**Houston**
Annual Generated Power by FC (kWh)	84,096	84,096	84,096	84,096	84,096
Annual Generated Heat by FC (kWh)	124,409	124,409	124,409	124,409	124,409
Avoided GHG [tCO2e/y]	10	54	48	21	15
Avoided NOx [tNOx/y]	0.042	0.128	0.117	0.049	0.041
Avoided SOx [tSOx/y]	0.033	0.233	0.371	0.075	0.040
Avoided PM10 [t/y]	*0.0015*	*0.0011*	*0.0014*	*0.0015*	*0.0007*
Avoided PM2.5 [t/y]	*0.0005*	*0.0002*	*0.0002*	*0.0004*	-
GHG credit at $44/ton CO_2 ($/kWhe)	0.0053	0.0282	0.0250	0.0111	0.0078
Health, Environmental Savings ($/kWhe)	0.0030	0.0238	0.0350	0.0158	0.0026

Table.7.15. Monetized marginal environmental and human health impacts of FCS operation scenarios for a 10kW FC system in a small hotel compared to grid-based electricity and conventional heating. The FCS system is assumed to only offset water heating.

7.3 Total Cost of Ownership Modeling Results

In Figure 7.7 we illustrate an approach for comparing fuel cell total cost of ownership with grid based electricity and conventional heating. A fuel cell CHP system will typically increase the cost of electricity but provide some savings by offsetting heating energy requirements. The cost of fuel cell electricity in this case is taken to be the "levelized cost of electricity" or the levelized cost in $/kWh for the fuel cell system taking into account capital costs, operations and maintenance (O&M), fuel, and capital replacement costs (inverter, stack replacement, etc.) only. In this work we credit saving from heating fuel savings, carbon credits from net system savings of CO2eq, and net avoided environmental and health-based externalities to the fuel cell system cost of electricity and call this quantity "cost of electricity with total cost of ownership savings." This allows comparison of fuel cell cost of electricity with TCO credits or "total cost of electricity" to the reference grid electricity cost ($/kWh).

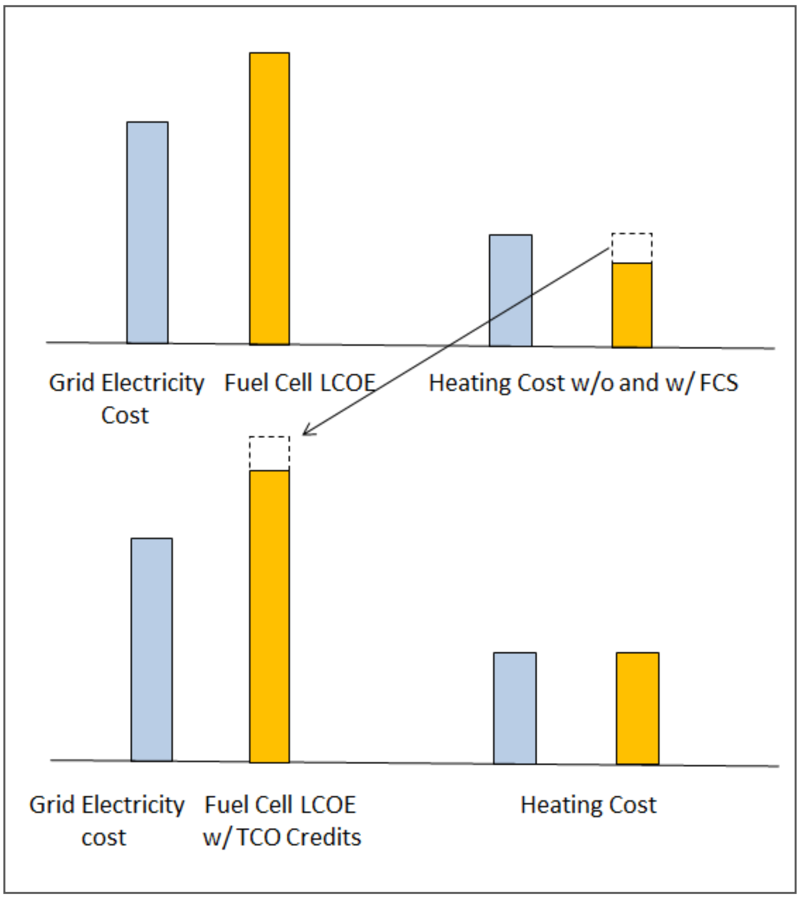


Figure 7.7. Cost of energy service for FC CHP and conventional electricity and heating systems. A fuel cell CHP system will typically increase the levelized cost of electricity (upper left two bars). But if waste heat is utilized, the cost of heating is reduced (upper right two bars). In this treatment, all non-electricity credits (heating fuel savings, carbon credits, societal health and environmental benefits) are applied to an LCOE with TCO credits or a "total cost of electricity" (lower left two bars).

Results for the small hotel case in five U.S. cities are shown below and presented for other building types in Appendix F. These tables represent a synthesis of the use-phase and LCIA modeling above.

Output results from use-phase model for small hotel (50 kW FC system)										
Output	**Phoenix, AZ**		**Minneapolis, MN**		**Chicago, IL**		**NYC, NY**		**Houston, TX**	
	No FCS	**Fuel Cell**	**No FCS**	**Fuel Cell**	**No FCS**	**Fuel Cell**	**No FCS**	**Fuel Cell**	**No FCS**	**Fuel Cell**
Total Electricity Demand (kWh/yr)	576,668	576,668	419,590	419,590	424,147	424,147	369,661	369,661	497,656	497,656
Total Space Heating Demand (kWh/yr)	23,307		174,743		135,869		135,869		0	
Total Water Heating Demand (kWh/yr)	76,954		127,112		118,971		116,075		83,071	
Annual Generated Power by FC (kWh)		382253		345368		345791		314930		362313
Annual Generated Heat by FC (kWh)		565468		501840		502765		454903		532839
FC fraction of Electricity Demand		66%		82%		82%		85%		73%
Capital Cost ($/yr)		13,970		13,970		13,970		13,970		13,970
O&M Cost ($/yr)		11,468		10,361		10,374		9,448		10,869
Scheduled Maintenance ($/yr)		1000		1000		1000		1,000		1,000
Fuel Cost for Fuel Cell ($/yr)		42227		27282		30995		3.19E+04		29422
Fuel Cost for Conv. Heating ($/yr)	3574	0	7779	84	7449	9	8352	8.89E+00	2185	0
Purchased Electricity Energy Cost ($/yr)	47305	15360	45374	6679	32104	4889	8798	9.90E+02	15427	3728
Demand Charge ($/yr)	5445	3635	3422	1937	6021	3460	16959	8882	15490	9422
Fixed Charge, Electricity ($/yr)	150	150	131	131	348	348	1241	1241	295	295
Total Electricity Cost ($/yr)	5.29E+04	87809	4.89E+04	61360	3.85E+04	65035	2.70E+04	67418	3.12E+04	6.87E+04
Total Cost of Electricity ($/kWh)	0.092	0.152	0.117	0.146	0.091	0.153	0.073	0.182	0.063	0.138
Purchased Electricity Cost ($/kWh)	0.092	0.098	0.117	0.118	0.091	0.111	0.073	0.203	0.063	0.099
LCOE of FC power ($/kWh)		**0.180**		**0.152**		**0.163**		**0.179**		**0.153**
Fuel savings from conventional heating ($/yr)		3574		7695		7440		8343		2185
Fuel savings per kWh($/kWh)		0.009		0.022		0.022		0.026		0.006
LCOE of FC power with fuel savings ($/kWh)		**0.170**		**0.130**		**0.141**		**0.152**		**0.146**
GHG credit at $44/ton CO_2 ($/kWh)		-0.0013		0.021		0.016		0.002		0.0003
Health, Environmental Savings ($/kWh)		0.0015		0.020		0.030		0.010		0.0018
LCOE with TCO Savings for Fuel Cell Power ($/kWh)		**0.170**		**0.088**		**0.095**		**0.140**		**0.144**
LCOE with TCO Savings for FC and Purchased Power, ($/kWh)		0.146		0.094		0.098		0.149		0.132

Table 7.16. Levelized cost of electricity with total cost of ownership savings for small hotels and 50kW FC systems providing hot water and space heating compared to grid-based cost of electricity.

Output results from use-phase model for small hotel (50 kW FC system)										
Output	Phoenix, AZ		Minneapolis, MN		Chicago, IL		NYC, NY		Houston, TX	
	No FCS	Fuel Cell	No FCS	Fuel Cell	No FCS	Fuel Cell	No FCS	Fuel Cell	No FCS	Fuel Cell
Total Electricity Demand (kWh/yr)	576,668	576,668	419,590	419,590	424,147	424,147	369,661	369,661	497,656	497,656
Total Space Heating Demand (kWh/yr)	23,307		174,743		135,869		135,869		0	
Total Water Heating Demand (kWh/yr)	76,954		127,112		118,971		116,075		83,071	
Annual Generated Power by FC (kWh)		382253		345368		345791		314930		362313
Annual Generated Heat by FC (kWh)		565468		501840		502765		454903		532839
FC fraction of Electricity Demand		66%		82%		82%		85%		73%
Capital Cost ($/yr)		13,970		13,970		13,970		13,970		13,970
O&M Cost ($/yr)		11,468		10,361		10,374		9,448		10,869
Scheduled Maintenance ($/yr)		1000		1000		1000		1,000		1,000
Fuel Cost for Fuel Cell ($/yr)		42227		27285		30998		31885		29421
Fuel Cost for Conv. Heating ($/yr)	3574	831	7780	4504	7450	3972	8351	4504	2185	0
Purchased Electricity Energy Cost ($/yr)	47305	15360	45374	6679	32104	4889	8798	990	15427	3728
Demand Charge ($/yr)	5445	3635	3422	1937	6021	3460	16959	8882	15490	9422
Fixed Charge, Electricity ($/yr)	150	150	131	131	348	348	1241	1241	295	295
Total Electricity Cost ($/yr)	52899	87809	48927	61363	38473	65038	26998	67415	31213	68706
Total Cost of Electricity ($/kWh)	0.092	0.152	0.117	0.146	0.091	0.153	0.073	0.182	0.063	0.138
Purchased Electricity Cost ($/kWh)	0.092	0.098	0.117	0.118	0.091	0.111	0.073	0.203	0.063	0.099
LCOE of FC power ($/kWh)		**0.180**		**0.152**		**0.163**		**0.179**		**0.153**
Fuel savings from conventional heating ($/yr)		2743		3276		3478		3847		2185
Fuel savings per kWh($/kWh)		0.007		0.009		0.010		0.012		0.006
LCOE of FC power with fuel savings ($/kWh)		**0.172**		**0.143**		**0.153**		**0.167**		**0.146**
GHG credit at $44/ton CO_2 ($/kWh)		-0.002		0.016		0.011		0.000		0.000
Health, Environmental Savings ($/kWh)		0.001		0.018		0.027		0.007		0.002
LCOE with TCO Savings for Fuel Cell Power ($/kWh)		**0.173**		**0.110**		**0.114**		**0.159**		**0.144**
LCOE with TCO Savings for FC and Purchased Power, ($/kWh)		0.148		0.111		0.114		0.166		0.132

Table 7.17. Levelized cost of electricity with total cost of ownership savings for small hotels and 50kW FC systems providing only hot water compared to grid-based cost of electricity.

In the paragraphs below, we provide a detailed evaluation for the results provided in Table 7.16. Other cases reflected in Tables. 7.17, 7.18, and 7.19 are discussed in terms of their deviation from the Table 7.16 base case.

We first consider all costs are from the use-phase and LCIA analysis above. Use-phase total costs are re-framed in this section in terms of levelized cost of electricity (LCOE), LCOE with fuel savings, and LCOE with fuel savings and externality valuation, all normalized to kWhe. Total cost of electricity (or purchased electricity cost) for the no FC case is taken to be the all-in cost of grid supplied electricity per kWh (sum of the annual energy cost, demand charges and any fixed charges divided by the building's annual electricity demand in kWh). This does not include the cost of heating fuels.

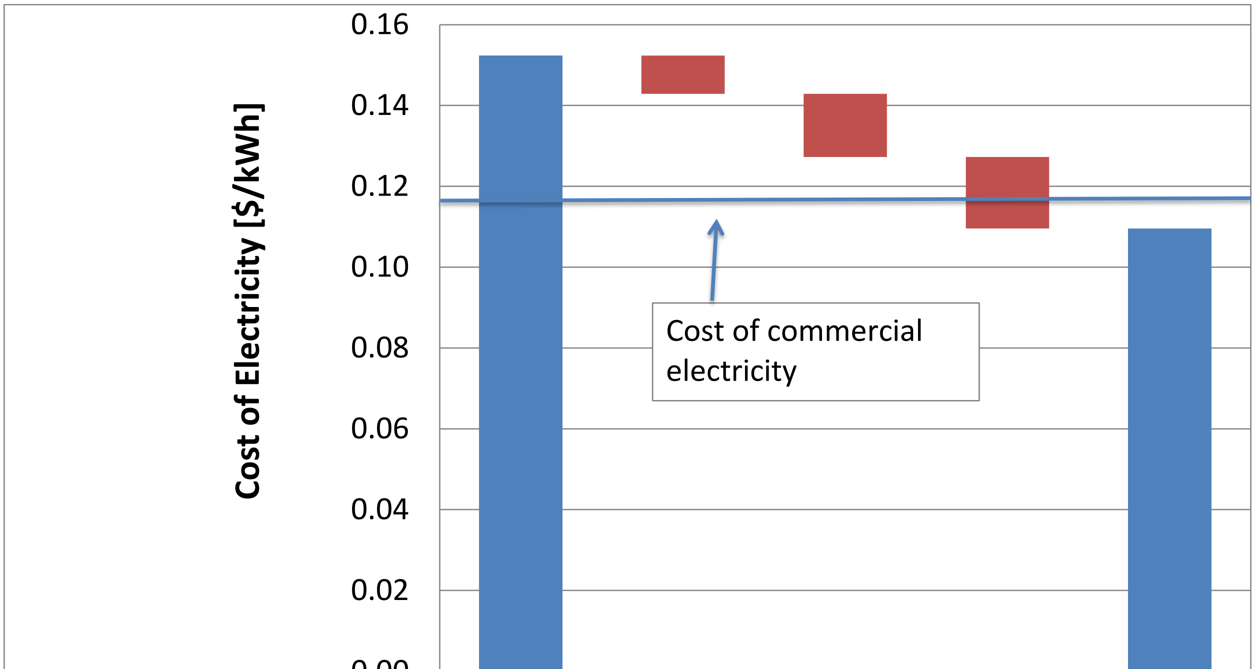
Total cost of electricity in the FC case includes all fuel cell capital and operational costs plus any purchased electricity costs, divided by the building's annual electricity demand in kWh. It does not include the cost of purchased fuel for conventional heating. Purchased cost electricity in the FC case includes grid-based electricity energy, demand and fixed charges, and is normalized to the amount of electricity purchased from the grid.

Similarly for fuel cells, the LCOE of FC power is taken to be the FC capital cost, O&M cost, scheduled maintenance costs and fuel costs for fuel cell system (FCS) operation, divided by the amount of annual electricity provided by the fuel cell system FCS. The LCOE of FC power in this definition includes all the fuel purchased for FCS operation, but none of the fuel purchased for conventional heating that augment the FCS waste heat utilization.

The LCOE of FC power is then credited with the fuel savings from the reduction in fuel required for conventional heating as illustrated in Figure 7.7, again normalized to annual electricity output of the FCS in kWh. GHG credits and health and environmental savings resulting from FCS operation derived in the preceding section are similarly normalized over the annual electricity output of the FCS.

An "LCOE with total cost of ownership savings (TCO) for FC Power" is calculated by subtracting the heating savings, GHG credit, and health and environmental savings. By contrast, an "LCOE with TCO savings for FC and purchased power" is the combination of purchased electricity cost in ($/kWh) and LCOE with TCO savings for FC power only, weighted by the relative fraction of demand from purchased electricity vs. FCS produced electricity.

For small hotels with 50kW FC systems (Table 7.17), Minneapolis and Chicago have the highest TCO savings for FC power among the five cities as they are in regions with higher carbon-intensity grid-based electricity. Minneapolis also has relatively lower natural gas fuel prices which is favorable for the LCOE of FC power. Considering the case of offset water heating only, TCO savings reduce the LCOE of FC power by 28% in Minneapolis (from $0.152/kWh to $0.11/kWh, shown in Table 7.17 and Figure 7.8) and by 30% in Chicago ($0.163/kWh to $0.114/kWh). Considering now both fuel cell electricity and purchased electricity, Minneapolis has a starting total cost of electricity with the FCS of $0.146/kWh which is higher than the commercial cost of electricity ($0.117) but then adding heating savings, GHG and health and environmental credits brings the LCOE with TCO savings for FC and Purchased Power $0.111/kWh, or below the cost of commercial electricity. These results are also plotted in Figure 7.9 below.



	Levelized Cost of Electricity	Heating Savings	GHG Credit at $44/ton CO2	Environ-mental and Health Savings	Cost of Electricity with TCO Savings
Savings ($/kWh)		0.009	0.016	0.018	
Cost of Electricity ($/kWh)	0.152	0.143	0.127	0.110	0.110

Figure 7.8. Levelized cost of electricity for a 50kW fuel cell CHP system in a small hotel in Minneapolis with offset water heating only. Water heating from the FCS contributes 6% savings and the GHG and health externality savings provide 22% savings.

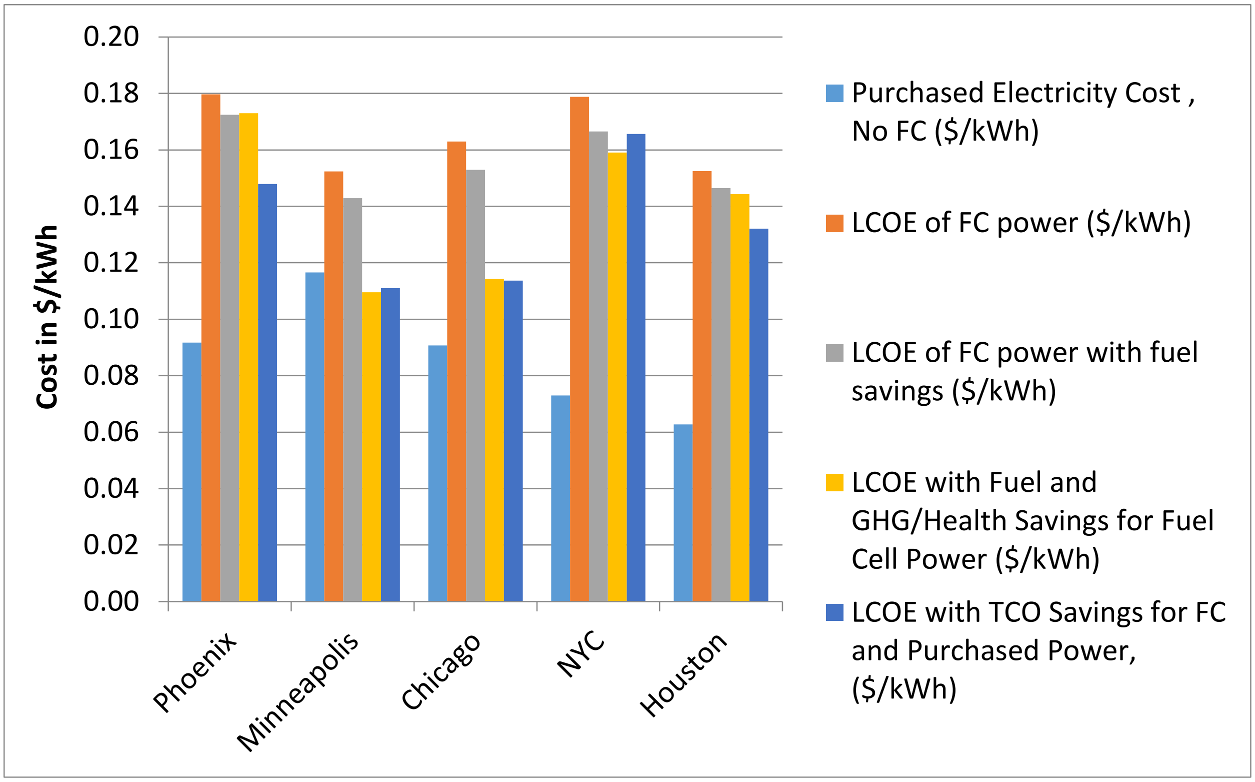


Figure 7.9. Levelized cost of electricity for a small hotel for the No Fuel Cell case (first bar for each city) compared to the case of a 50kW fuel cell CHP system and grid electricity (subsequent bars for each city).

Output results from use-phase model for small hotel (10 kW FC system)										
Output	**Phoenix, AZ**		**Minneapolis, MN**		**Chicago, IL**		**NYC, NY**		**Houston, TX**	
	No FCS	**Fuel Cell**	**No FCS**	**Fuel Cell**	**No FCS**	**Fuel Cell**	**No FCS**	**Fuel Cell**	**No FCS**	**Fuel Cell**
Total Electricity Demand (kWh/yr)	576,668	576,668	419,590	419,590	424,147	424,147	369,661	369,661	497,656	497,656
Total Space Heating Demand (kWh/yr)	23,307		174,743		135,869		135,869		0	
Total Water Heating Demand (kWh/yr)	76,954		127,112		118,971		116,075		83,071	
Annual Generated Power by FC (kWh)		84,096		84,096		84,096		84,096		84,096
FC fraction of Electricity Demand		15%		20%		20%		23%		17%
Annual Generated Heat by FC (kWh)		124409		124409		124409		124409		124409
Capital Cost ($/yr)		3757		3757		3757		3757		3757
O&M Cost ($/yr)		2523		2523		2523		2523		2523
Scheduled Maintenance ($/yr)		500		500		500		500		500
Fuel Cost for Fuel Cell ($/yr)		8994		6501		7374		8363		6635
Fuel Cost for Conv. Heating ($/yr)	3574	554	7779	4698	7449	4000	8352	4452	2185	211
Purchased Electricity Energy Cost	47305	40333	45374	35998	32104	25495	8798	6713	15427	12712
Demand Charge ($/yr)	5445	5093	3422	3125	6021	5508	16959	15344	15490	14321
Fixed Charge, Electricity ($/yr)	150	150	131	131	348	348	1241	1241	295	295
Total Electrictiy Cost ($/yr)	52899	61350	48927	52535	38473	45506	26998	38441	31213	40744
Total Cost of Electricity ($/kWh)	0.092	0.106	0.117	0.125	0.091	0.107	0.073	0.104	0.063	0.082
Purchased Electricity Cost ($/kWh)	0.092	0.093	0.117	0.117	0.091	0.092	0.073	0.082	0.063	0.066
LCOE of FC power ($/kWh)		**0.188**		**0.158**		**0.168**		**0.180**		**0.160**
Fuel savings from conventional heating ($/yr)		3021		3081		3449		3900		1974
Fuel savings per kWh ($/kWh)		0.036		0.037		0.041		0.046		0.023
LCOE of FC power with fuel savings ($/kWh)		**0.152**		**0.121**		**0.127**		**0.134**		**0.136**
GHG credit at $44/ton CO_2 ($/kWh)		0.008		0.028		0.026		0.012		0.008
Health, Environmental Savings ($/kWh)		0.004		0.024		0.035		0.017		0.003
LCOE with TCO Savings for Fuel Cell Power ($/kWh)		**0.140**		**0.069**		**0.066**		**0.105**		**0.126**
LCOE with TCO Savings for FC and Purchased Power, ($/kWh)		0.099		0.107		0.087		0.087		0.076

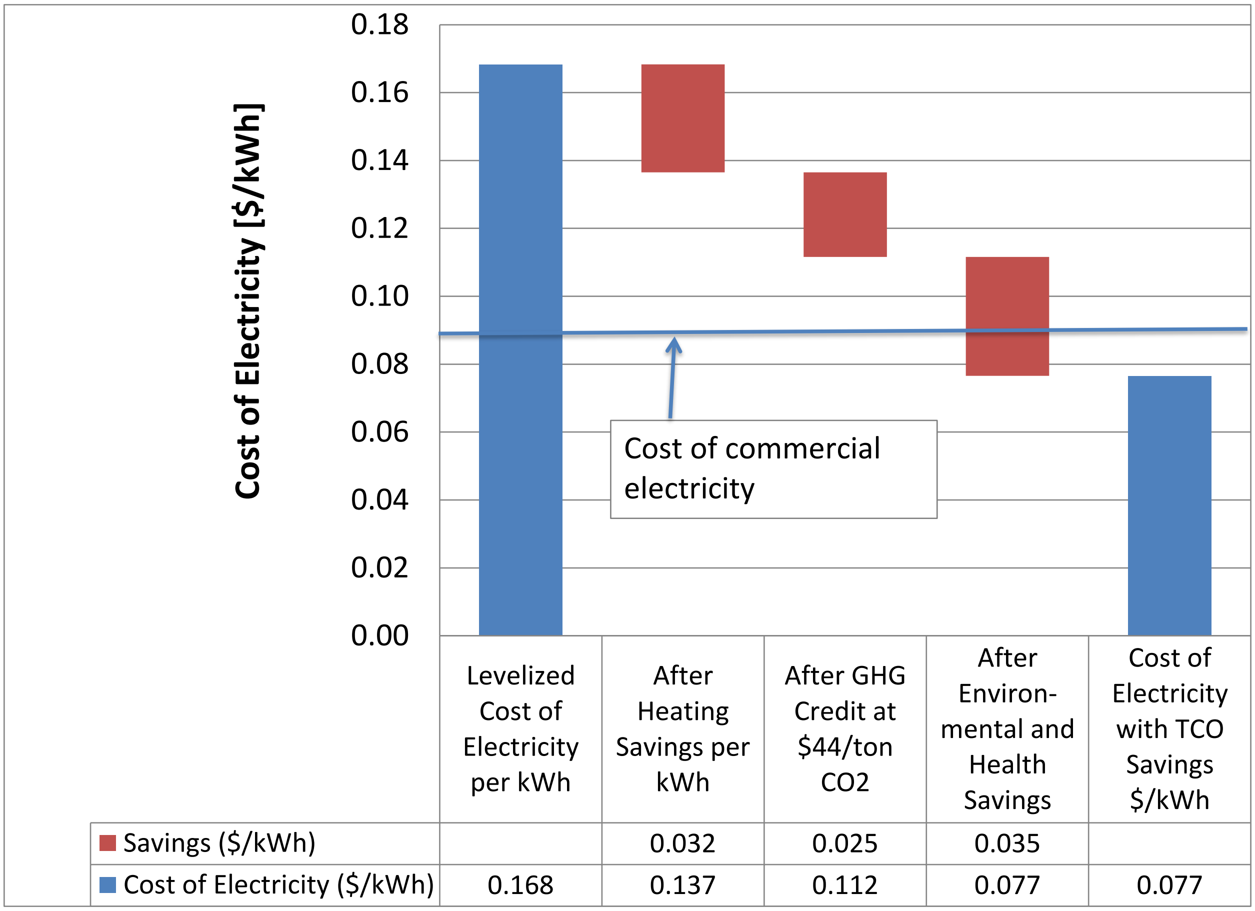
Table 7.18. Levelized cost of electricity with total cost of ownership savings for small hotels and 10kW FC systems providing hot water and space heating compared to grid-based cost of electricity.

Output results from use-phase model for small hotel (10 kW FC system)										
Output	Phoenix, AZ		Minneapolis, MN		Chicago, IL		NYC, NY		Houston, TX	
	No FCS	Fuel Cell	No FCS	Fuel Cell	No FCS	Fuel Cell	No FCS	Fuel Cell	No FCS	Fuel Cell
Total Electricity Demand (kWh/yr)	576,668	576,668	419,590	419,590	424,147	424,147	369,661	369,661	497,656	497,656
Total Space Heating Demand (kWh/yr)	23,307		174,743		135,869		135,869		0	
Total Water Heating Demand (kWh/yr)	76,954		127,112		118,971		116,075		83,071	
Annual Generated Power by FC (kWh)		84,096		84,096		84,096		84,096		84,096
FC fraction of Electricity Demand		15%		20%		20%		23%		17%
Annual Generated Heat by FC (kWh)		124409		124409		124409		124409		129,593
Capital Cost ($/yr)		3757		3757		3757		3757		3757
O&M Cost ($/yr)		2523		2523		2523		2523		2523
Scheduled Maintenance ($/yr)		500		500		500		500		500
Fuel Cost for Fuel Cell ($/yr)		8994		6501		7374		8363		6635
Fuel Cost for Conv. Heating ($/yr)	3574	1068	7779	5344	7449	4777	8352	5353	2185	211
Purchased Electricity Energy Cost ($/yr)	47305	40333	45374	35998	32104	25495	8798	6713	15427	12712
Demand Charge ($/yr)	5445	5093	3422	3125	6021	5508	16959	15344	15490	14321
Fixed Charge, Electricity ($/yr)	150	150	131	131	348	348	1241	1241	295	295
Total Electrictiy Cost ($/yr)	52899	61350	48927	52535	38473	45506	26998	38441	31213	40744
Total Cost of Electricity ($/kWh)	0.092	0.106	0.117	0.125	0.091	0.107	0.073	0.104	0.063	0.082
Purchased Electricity Cost ($/kWh)	0.092	0.093	0.117	0.117	0.091	0.092	0.073	0.082	0.063	0.066
LCOE of FC power ($/kWh)		**0.188**		**0.158**		**0.168**		**0.180**		**0.160**
Fuel savings from conventional heating ($/yr)		2506		2434		2671		2999		1974
Fuel savings per kWh ($/kWh)		0.030		0.029		0.032		0.036		0.023
LCOE of FC power with fuel savings ($/kWh)		**0.158**		**0.129**		**0.137**		**0.144**		**0.136**
GHG credit at $44/ton CO_2 ($/kWh)		0.005		0.028		0.025		0.011		0.008
Health, Environmental Savings ($/kWh)		0.003		0.024		0.035		0.016		0.003
LCOE with TCO Savings for Fuel Cell Power ($/kWh)		**0.149**		**0.077**		**0.077**		**0.117**		**0.126**
LCOE with TCO Savings for FC and Purchased Power, ($/kWh)		0.101		0.109		0.089		0.090		0.076

Table 7.19. Levelized cost of electricity with total cost of ownership savings for small hotels and 10kW FC systems providing hot water compared to grid-based cost of electricity.

For small hotels with 10kW FC systems and offset water heating (Table 7.19), Minneapolis and Chicago realize about 55% TCO savings to the LCOE for fuel cell power with all of the TCO values added. The number is much higher than the 50kW case since a much larger fraction of FCS heat is utilized. However, in this case the FCS only provides about 20% of the building's total electricity demand leaving the facility mainly reliant on grid power.

The case of Chicago is depicted in Figure 7.10 below. Overall, the LCOE with TCO savings for FC and Purchased Power is lower than the Total Cost of Electricity in Minneapolis and Chicago than the other cities ($0.108/kWh vs. $0.117/kWh in Minneapolis and $0.089/kWh vs. $0.091/kWh in Chicago). The results in Table 7.19 for all cities are shown graphically in Figure 7.11 below.



	Levelized Cost of Electricity per kWh	After Heating Savings per kWh	After GHG Credit at $44/ton CO2	After Environ-mental and Health Savings	Cost of Electricity with TCO Savings $/kWh
Savings ($/kWh)		0.032	0.025	0.035	
Cost of Electricity ($/kWh)	0.168	0.137	0.112	0.077	0.077

Figure 7.10. Levelized cost of electricity for a 10kW fuel cell CHP system in a small hotel in Chicago with offset water heating only. Water heating from the FCS contributes 19% savings per kWh and the GHG and health externality savings provide 36% savings.

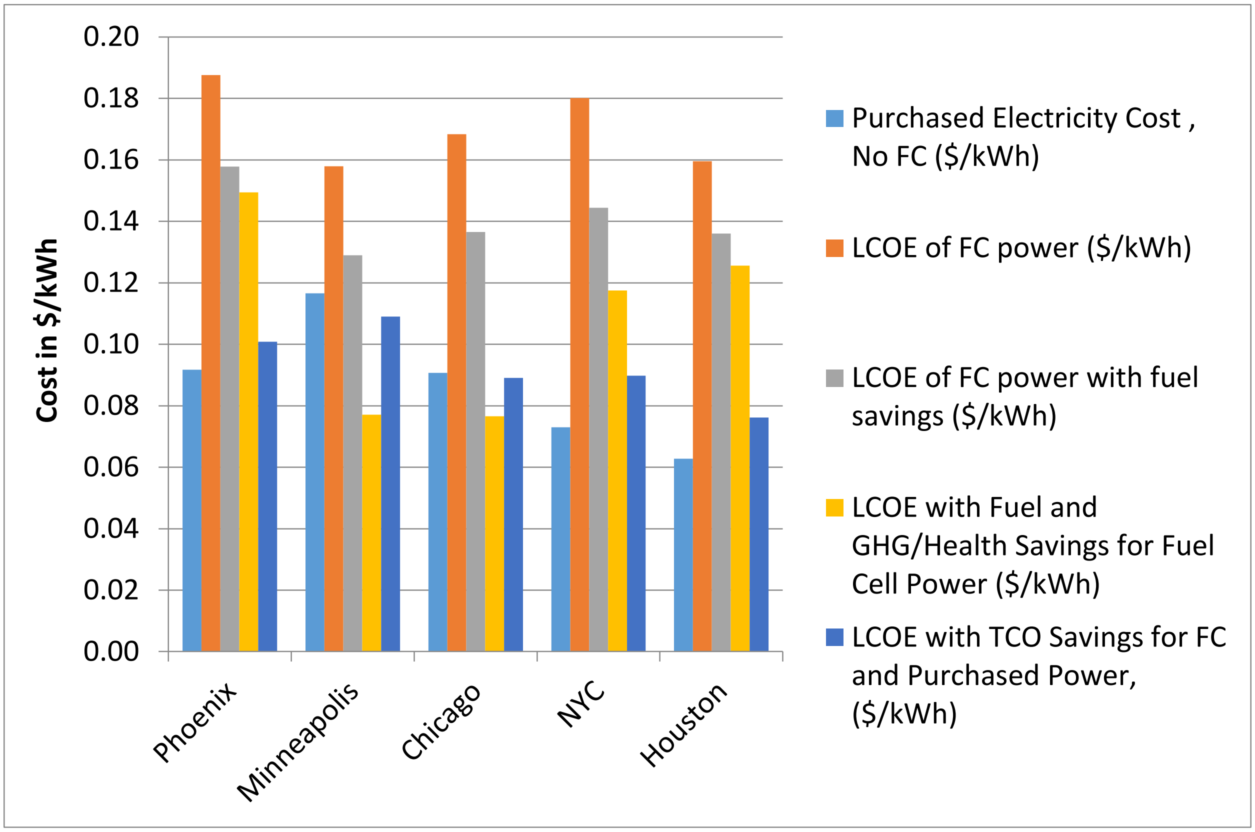


Figure 7.11. Levelized cost of electricity for a small hotel for the No Fuel Cell case (first bar for each city) compared to the case of a 10kW fuel cell CHP system and grid electricity (subsequent bars for each city).

8 Conclusions

Bottom-up DFMA costing analysis for fuel cell stack components in this work shows that, for stationary applications, LT PEM fuel cell stacks alone can approach a direct manufacturing cost of $200 per kWe of net electrical power at high production volumes (e.g. 100kW CHP systems at 50,000 systems per year). Overall system costs including corporate markups and installation costs are estimated to be about $1800/kWe ($1600/kWe) for 100kW (250kW) CHP systems at 50,000 systems per year, and about $1100/kWe for 10kWe backup power systems at 50,000 systems per year.

All fuel cell stack components (CCM, GDL, framed MEA, plates and stack assembly are assumed to be manufactured in-house with high throughput processes and high yield (>95%) assumed for all modules at high manufacturing volumes. Nearly fully automated roll-to-roll processing is modeled for the critical catalyst coated membrane and for the GDL. The assumed yield rates are a key uncertain variable in estimating fuel cell stack manufacturing costs. While it was not in the scope of this work to do a detailed yield feasibility analysis, well established methodologies exist for improving yield using similar process modules in other industries, and learning-by-doing and improvements in yield inspection, detection, and process control are implicitly assumed. Most system balance of plant components were assumed to be purchased from suppliers as they are generally available as commercial products.

Balance of plant costs including the fuel processor make up about 65-75% of total direct costs for 100 kWe CHP systems across the range of production volumes and are thus a key opportunity for further cost reduction. The BOP has a lower rate of decrease in cost as a function of volume as the fuel cell stack in part because it is made up of largely commodity components and does not benefit in the same way from increased economies of scale as the fuel cell stack. This result is also influenced by the different methodologies applied to stack vs. BOP costing: a DFMA analysis was applied to the stack, whereas BOP costs were estimated based on purchased components and vendor price quotes.

The cost of electricity with TCO credits for a fuel cell CHP system has been demonstrated for buildings in six U.S. cities. This approach incorporates the impacts of offset heating demand by the FCS, carbon credits, and environmental and health externalities into a total levelized cost of electricity ($/kWh). This LCOE with total cost of ownership credits can then be compared with the baseline cost of grid electricity. This analysis combines a fuel cell system use-phase model with a life-cycle integrated assessment model of environmental and health externalities. Total cost of electricity is dependent on the carbon intensity of electricity and heating fuel that a FC system is displacing, and thus highly geography dependent.

For the subset of buildings considered here (small hotels, hospitals, and office buildings), overall TCO costs of fuel cell CHP systems relative to grid power only exceed prevailing power rates at the system sizes and production volumes studied, except in regions of the country with higher carbon intensity grid electricity. Including total cost of ownership credits can bring the levelized cost of electricity below the cost of electricity purchased from the grid in Minneapolis and Chicago. Health and environmental externalities can provide large savings if electricity or heating with a high environmental impact are being displaced.

Overall, this type of total cost of ownership analysis quantification is important to identify key opportunities for direct cost reduction, to fully value the costs and benefits of fuel cell systems in stationary applications, and to provide a more comprehensive context for future potential policies.

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Appendix A: Functional Specifications

Parameter	CHP Reformate Fuel System, 1 kWe	CHP Reformate Fuel System, 50 kWe	CHP Reformate Fuel System, 250 kWe	Unit
Gross system power	1.3	63.3	308.8	kWe
Net system power	1	50	250	kWe
Electrical output	110V AC	480V AC	480V AC	Volts AC or DC
DC/AC inverter efficiency	93	93	93	%
Waste heat grade	65	65	65	Temp. °C
Reformer Efficiency	75	75	75	%
Fuel utilization, overall	95	95	95	%
Net electrical efficiency	31.3	32.0	33.0	% LHV
Thermal efficiency	49.0	50.0	52.0	% LHV
Total efficiency	80.0	82.0	85.0	Elect.+thermal (%)
Stack power	1.3	10.5	9.4	kWe
Total plate area	363	363	363	cm2
CCM coated area	259.2	259.2	259.2	cm2
Single cell active area	220.3	220.3	220.3	cm2
Gross cell inactive area	38.8	38.8	38.8	%
Cell amps	109	110.8	111.4	A
Current density	049	0.503	0.506	A/cm2
Reference voltage	0.70	0.70	0.70	V
Power density	0.346	0.352	0.354	W/cm2
Single cell power	76.2	77.5	78.0	W
Cells per stack	17	136	120	Cells
Stacks per system	1	6	33	Stacks
Parasitic Loss	0.22	9.5	40.0	kWe

Table A.1. Functional specifications for CHP fuel cell system with reformate fuel for 1Kw, 50kW and 250kW system sizes.

Appendix B: DFMA Analysis Techniques

This section discusses economic analysis used in developing DFMA costing model. This model was adopted from ASHRAE handbook (See Haberl 1994 for more details). Below are the definitions of terms used in developing economic equations:

- $\mathbf{C_e}$= cost of energy to operate the system for one period
- $\mathbf{C_f}$= floorspace (building) cost
- $\mathbf{C_{labor}}$ =labor rate per hour
- $\mathbf{C_{s,assess}}$= initial assessed system value
- $\mathbf{C_{s,salvage}}$= system salvage value at the end of its useful life in constant dollars
- $\mathbf{C_{s\ init}}$ = initial system cost
- $\mathbf{C_y}$= annualized system cost in constant dollars
- $\mathbf{D_{k,sl}}$ or $\mathbf{D_{k,SD}}$ = amount of depreciation at the end of period k depending on the type of depreciation schedule used, where D_{ksl} is the straight line depreciation method and D_{kSD} represents the sum-of-digits depreciation method in constant dollars
- **F**= future value of a sum of money
- $\mathbf{i_m P_k}$ = interest charge at the end of period k
- $i' = (i_d - j)/1+j)$ = effective discount rate adjusted for energy inflation;, sometimes called the real discount rate
- $i'' = (i_d - j_e)/1+ j_e)$ = effective discount rate adjusted for energy inflation j_e
- **I**= annual insurance costs
- **ITC**= investment tax credit for energy efficiency improvements, if applicable
- j= general inflation rate per period
- $\mathbf{j_d}$= discount rate
- j_{br} = building depreciation rate
- j_e = general energy inflation rate per period
- $\mathbf{j_m}$ = average mortgage rate (real rate + general inflation rate)
- k= end if period(s) in which replacement(s), repair(s), depreciation, or interest is calculated
- M= periodic maintenance cost
- n= number of period(s) under consideration
- P= a sum of money at the present time, *i.e.,* its present value
- P_k= outstanding principle of the loan for C-s,init at the end of period k in current dollars
- R_k= net replacement(s), repair cost(s), or disposals at the end of period k in constant dollars
- T_{inc}= (state tax rate + federal tax rate) -(state tax rate X federal tax rate) where tax rates are based on the last dollar earned, i. *e.,* the marginal rates
- T_{prop} = property tax rate
- T_{br} = salvage value of the building

For any proposed capital investment, the capital and interest costs, salvage costs, replacement costs, energy costs, taxes, maintenance costs, insurance costs, interest deductions, depreciation allowances, and other factors must be weighed against the value of the services provided by the system.

Single Payment

Present value or present worth is a common method for analyzing the impact of a future payment on the value of money at the present time. The primary underlying principle is that all monies (those paid now and in the future) should be evaluated according to their present purchasing power. This approach is known as discounting. The future value F of a present sum of money P over n periods with compound interest rate i can be calculated as following:

$$F = p(1 + i)^n$$

The present value or present worth P or a future sum of money F is given by:

$$P = {}^{F}\!/_{(1 + i)^n} = F \times PWF(i, n)$$

where PWF(i,n) the worth factor, is defined by:

$$PWF(i, n) = {}^{1}\!/_{(1 + i)^n}$$

Accounting for Varying Inflation Rates

Inflation is another important economic parameter which accounts for the rise in costs of a commodity over time. Inflation must often be accounted for in an economic evaluation. One way to account for this is to use effective interest rates that account for varying rates of inflation.
The effective interest rate i', sometimes called the real rate, accounts for the general inflation rate $\boldsymbol{j}$ and the discount rate j_d , and can be expressed as follows (Haberl 1994).):

$$i' = \frac{1+j_d}{1+j} - 1 = \frac{j_d - j}{1+j}$$

However, this expression can be adapted to account for energy inflation by considering the general discount rate $j_d$and the energy inflation rate ***je,*** thus:

$$i'' = \frac{1+j_d}{1+j_e} - 1 = \frac{j_d - j_e}{1+j_e}$$

When considering the effects of varying inflation rates, the above discount equations can be revised to get the following equation for the future value *F,* using constant currency of an invested sum *P* with a discount rate j_d under inflation $\boldsymbol{j}$ during *n* periods:

$$F = P[\frac{1 + j_d}{1 + j}]^n = P(1 + i')^n$$

The present worth *P,* in constant dollars, of a future sum of money *F* with discount rate j_d under inflation rate $\boldsymbol{j}$ during $\boldsymbol{n}$ periods is then expressed as:

$$P = F/[\frac{1 + j_d}{1 + j}]^n$$

In constant currency, the present worth P of a sum of money *F* can be expressed with an effective interest rate i', which is adjusted for inflation by:

$$P = {}^{F}\!/_{(1 + i')^n} = F \times PWF(i', n)$$

where the effective present worth factor is given by:

$$PWF(i', n) = {}^{1}\!/_{(1 + i')^n}$$

Recovering Capital as a Series of Payments

Another important economic concept is the recovery of capital as a series of uniform payments or what so called - the capital recovery factor (CRF). CRF is commonly used to describe periodic uniform mortgage or loan payments and defined *S* as the ratio of the periodic payment to the total sum being repaid. The discounted sum *S* of such an annual series of payments ***Pann*** invested over ***n*** periods with interest rate ***i*** is given by:

$$S = P_{ann}[1 + (1 + i)^{-n}/i$$

$$P_{ann} = (S \times i)/[1 + (1+i)^{-n}/i$$
$$CRF(i,n) = \frac{i}{[1-(1+i)^{-n}]} = \frac{i(1+i)^n}{(1+i)^n - 1}$$

Table B.1 below summarizes some of the mathematical formulas used in calculating these cost components.

$(CRF_{i,init} - ITC)CRF(i',n)$	Capital and Interest
$(C_{s,slv}PWF(i',n)CRF(i',n)(1-T_{salv})$	Salvage Value
$\sum_{k=1}^{n}[R_k PWF(i',k)]\, CRF(i',n)(\,1-T_{inc})$	Replacement or Disposal
$C_e[\frac{CRF(i',n)}{CRF(i'',n)}](1-T_{inc})$	Operating Energy
$\mathrm{C_{br}} = CRF_m \times c_{fs} \times a_{br}$	Building Cost
$C_{s,assess}T_{prop}(1-T_{inc})$	Property Tax
$M(1-T_{inc})$	Maintenance
$I(1-T_{inc})$	Insurance
$T_{inc}\sum_{k=1}^{n}[j_m P_{k-1} PWF(i_d,k)]\, CRF(i',n)$	Interest Tax Deduction
$T_{inc}\sum_{k=1}^{n} D_k PWF(i_d,k)]\, CRF(i',n)$	Depreciation
$P_k = (C_{i,init} - ITC)\left[(1+j_m)^{k-1} + \frac{(1+j_m)^{k-1}-1}{(1+j_m)^{-n}-1}\right]$	Principle P_k during year K at market mortgage rate i_m

Table B.1. Cost components and their corresponding mathematical formulas

Discount Rate

The discount rate is expected to have a range of parameters depending on several financial factors including the "investment risk" reflected in the respective cost of equity and debt for a manufacturing company and the company's debt to equity ratio. The impact of the financial crisis is assumed to be neutral with respect to pre-financial crises numbers with a tradeoff in lower risk free rates and increased risk premiums. For the fuel cell industry, the weighted average cost of capital is expected to be in the range of 10-15%[20]. The lower value may be applicable to a supplier of component parts which have unit manufacturing processes which are shared with many other industries e.g., metal stamping or injection molding for bipolar plates. Here however, we adopt the upper range of discount rate based on the assumption that there is a vertically integrated manufacturing concern, industry inputs and an overall leaning to be conservative in overall cost assumptions. Also note that the discount rate, along with several other key global parameters was varied for sensitivity analysis.

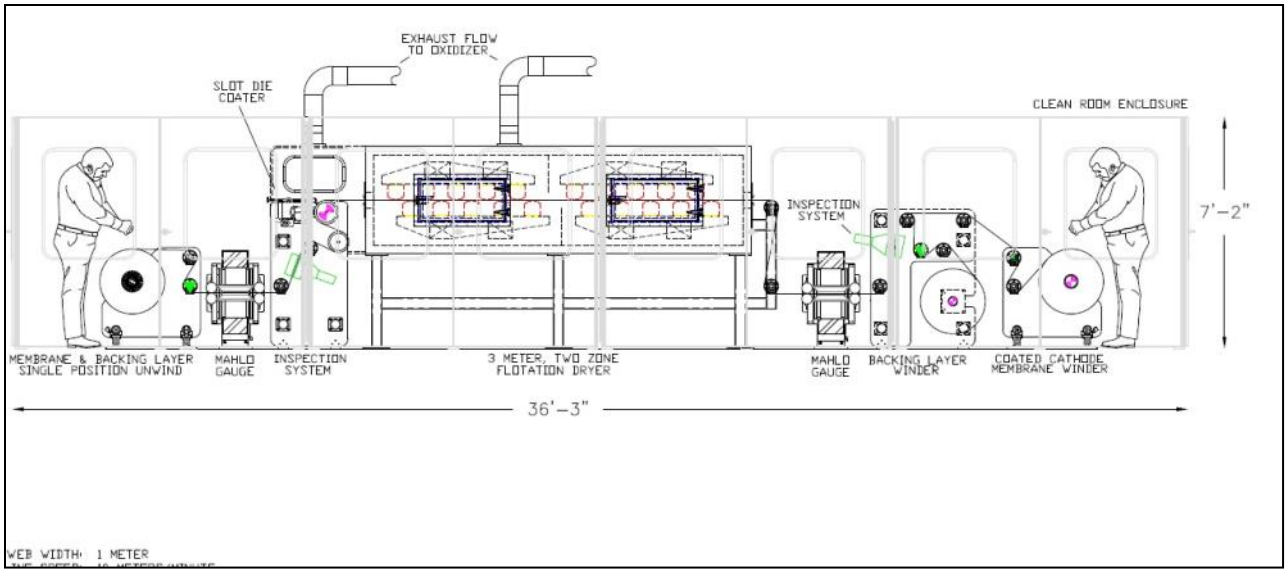
[20] See for example http://www.wikiwealth.com/wacc-analysis:fcel which provides an analysis for Fuel Cell Energy's weighted average cost of capital (WACC).

Appendix C: DFMA Analyses for Stack Component Costing

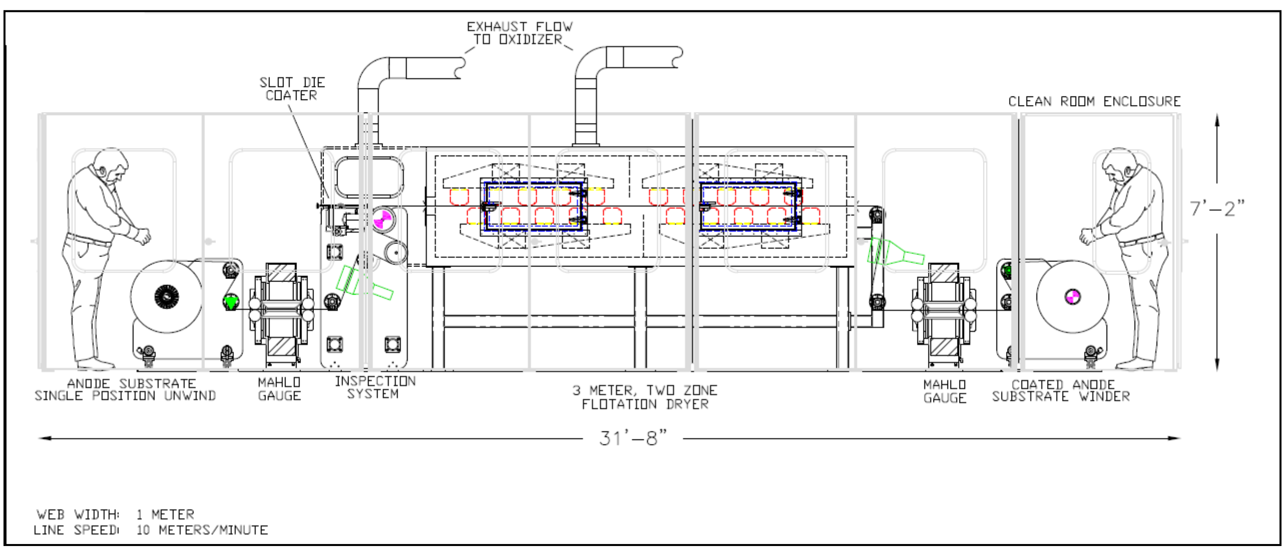
Catalyst Coated Membrane

Slot-die coating line layout from Conquip

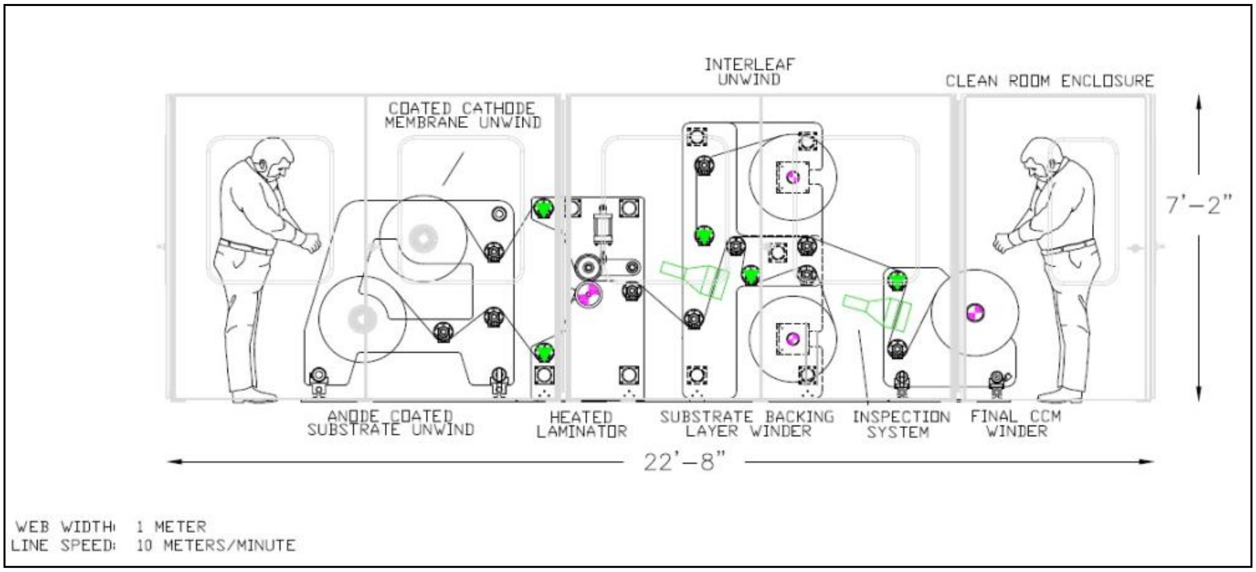
Figure C.1 shows side view diagrams of one detailed equipment configuration from web line vendor Conquip Inc.



(a) Cathode line



(b) Anode line



(c) Final product

Figure C.1. Slot-die coating line (source: Conquip Inc.) showing another manufacturing implementation and required tooling elements: (a) Cathode line; (b) Anode line; and (c) Final product

Equipment	**Qty**	**Potential Supplier**	**Total Section Cost (X1000)**
Slot Die	1	Coating Tech Slot Dies	$48
Slot-die station	1	ConQuip, Inc.	$400
Oxidizer	1	Tann Corp	$200
Enclosure for Class 1,000 Clean Room	1	ConQuip, Inc.	$75
IR Oven	1	Radiant	$180
Mixing System	1	Ross	60
Solution Delivery System	1	Moyno	$42
Inspection System	2	Mahlo America	$200
Vision System	2	Wintress Engineering	$150
Substrate Unwind	1	ConQuip, Inc.	$65
Coated Substrate Winder	1	ConQuip, Inc.	$65

Backing Layer Winder	1	ConQuip, Inc.	$40
Installation	1	ConQuip, Inc.	$130

Table C.1. Required equipment for decal transfer coating system (slot-die coater) Cathode Coating Station

Equipment	**Qty**	**Potential Supplier**	**Total Section Cost (X1000)**
Slot Die	1	Coating Tech Slot Dies	$48
Slot-die station	1	ConQuip, Inc.	$400
Oxidizer	1	Tann Corp	$200
Enclosure for Class 1,000 Clean Room	1	ConQuip, Inc.	$75
IR Oven	1	Radiant	$180
Mixing System	1	Ross	$60
Solution Delivery System	1	Moyno	$42
Inspection System	2	Mahlo America	$200
Vision System	2	Wintress Engineering	$150
Substrate Unwind	1	ConQuip, Inc.	$65
Coated Substrate Winder	1	ConQuip, Inc.	$65
Installation	1	ConQuip, Inc.	$130

Table C. 2. Required equipment for decal transfer coating system (slot-die coater) Anode Coating Station

Equipment	Qty	Potential Supplier	Total Section Cost (X1000)
Enclosure for Class 1,000 Clean Room	1	ConQuip, Inc.	$75
Coated Substrate Unwinder	1	ConQuip, Inc.	$65
Coated Membrane Unwinder	1	ConQuip, Inc.	$65
Laminator with Heated Rubber Roll Station	1	ConQuip, Inc.	$70
Substrate Unwind	1	ConQuip, Inc.	$40
Interleaf Winder	1	ConQuip, Inc.	$40
Final CCM Rewind	1	ConQuip, Inc.	$65
Vision System	2	Wintress Engineering	$150
Installation	1	ConQuip, Inc.	$130

Table C.3. Required equipment for decal transfer coating system (slot-die coater) Final Product Station

Machine Rate calculations for CCM coating line

Mixing and Pumping Unit:

Some important assumptions for mixing and pumping are:

- Assumes Class 1000 clean room
- Assumes ultrasonic mixer and precise pump
- Maintenance factor per James et al. (2010)
- Power consumption (4kW)
- Machine footprint based on web width and line length and assumed clean room.

Size (kW)	100			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Maintenance Factor	0.1	0.1	0.1	0.1
Power Consumption (kW)	4	4	4	4
Machine footprint (m2)	8.4	8.4	8.4	16.8
Initial Capital ($)	2.04E+05	2.04E+05	2.04E+05	4.08E+05
Initial System Cost ($)	2.24E+05	2.24E+05	2.24E+05	4.49E+05
Depreciation ($/yr)	1.33E+04	1.33E+04	1.33E+04	2.67E+04
Amortized Capital ($/yr)	3.31E+04	3.31E+04	3.31E+04	6.62E+04

Auxiliary Costs ($/yr)	0	0	0	0
Maintenance Costs ($/yr)	3008.94	3008.94	3008.94	6017.89
Salvage Value ($/yr)	368.45	368.45	368.45	736.89
Energy Costs ($/yr)	27.22	268.62	2656.77	6574.55
Property Tax ($/yr)	1126.08	1126.08	1126.08	2252.16
Building Costs ($/yr)	10167.79	10167.79	10167.79	20335.58
Interest Tax Deduction ($/yr)	0	0	0	0
Depreciation Deduction ($/yr)	0	0	0	0
Machine Rate ($/hr)	**1654.13**	**168.47**	**17.89**	**29.29**
- Capital ($/hr)	1150.44	116.57	11.79	19.05
- Operational ($/hr)	106.72	11.67	2.04	3.66
- Building ($/hr)	396.97	40.22	4.07	6.57

Table C.4. Machine rates for mixing and pumping unit

Quality Control Unit:

Some important assumptions for control module are:

- Two vision systems from Wintress Engineering and thickness measurement system from Mahlo America to ensure uniform deposition and thickness of the coated layers and final CCM
- Maintenance factor per James et al., (2010)
- Power consumption (15kW)
- Machine footprint based on web width and line length and assumed Class 1000 clean room

Size (kW)	**100**			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Maintenance Factor	0.1	0.1	0.1	0.1
Power Consumption (kW)	15	15	15	15
Machine footprint (m2)	5.6	5.6	5.6	11.2
Initial Capital ($)	3.00E+05	3.00E+05	3.00E+05	1.70E+06
Initial System Cost ($)	3.30E+05	3.30E+05	3.30E+05	1.87E+06
Depreciation ($/yr)	1.96E+04	1.96E+04	1.96E+04	1.11E+05
Amortized Capital ($/yr)	4.87E+04	4.87E+04	4.87E+04	2.76E+05
Auxiliary Costs ($/yr)	0	0	0	0
Maintenance Costs ($/yr)	4.42E+03	4.42E+03	4.42E+03	2.51E+04
Salvage Value ($/yr)	5.42E+02	5.42E+02	5.42E+02	3.07E+03
Energy Costs ($/yr)	1.53E+02	1.51E+03	1.49E+04	3.70E+04
Property Tax ($/yr)	1.66E+03	1.66E+03	1.66E+03	9.38E+03
Building Costs ($/yr)	6.78E+03	6.78E+03	6.78E+03	1.36E+04

Interest Tax Deduction ($/yr)	0	0	0	0
Depreciation Deduction ($/yr)	0	0	0	0
Machine Rate ($/hr)	**2.15E+03**	**2.23E+02**	**2.73E+01**	**1.04E+02**
- Capital ($/hr)	1.69E+03	1.71E+02	1.73E+01	7.94E+01
- Operational ($/hr)	1.61E+02	2.11E+01	6.97E+00	1.81E+01
- Building ($/hr)	2.96E+02	3.00E+01	3.04E+00	6.68E+00

Table C.5. Machine rates for Quality Control Module

Wind & Unwind Tensioners:

- Assume motorized to feed and control the web tension
- Manual load and unload of web
- Power consumption (10kW)
- Machine footprint based on web width and line length and assumed Class 1000 clean room

Size (kW)	**100**			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Maintenance Factor	0.1	0.1	0.1	0.1
Power Consumption (kW)	10	10	10	10
Machine footprint (m2)	19.6	19.6	19.6	39.2
Initial Capital ($)	1.33E+02	1.33E+02	1.33E+02	1.29E+06
Initial System Cost ($)	1.47E+02	1.47E+02	1.47E+02	1.42E+06
Depreciation ($/yr)	8.71E+00	8.71E+00	8.71E+00	8.43E+04
Amortized Capital ($/yr)	2.16E+01	2.16E+01	2.16E+01	2.09E+05
Auxiliary Costs ($/yr)	0	0	0	0
Maintenance Costs ($/yr)	1.97	1.97	1.97	19027.14
Salvage Value ($/yr)	0.24	0.24	0.24	2329.87
Energy Costs ($/yr)	68.05	671.54	6641.93	16436.37
Property Tax ($/yr)	0.74	0.74	0.74	7120.80
Building Costs ($/yr)	2.37E+04	2.37E+04	2.37E+04	4.74E+04
Interest Tax Deduction ($/yr)	0	0	0	0
Depreciation Deduction ($/yr)	0	0	0	0
Machine Rate ($/hr)	**837.15**	**86.98**	**10.94**	**86.44**
- Capital ($/hr)	0.75	0.08	0.01	60.23
- Operational ($/hr)	2.46	2.40	2.39	10.32
- Building ($/hr)	833.94	84.50	8.54	15.88

Table C. 6. Machine rates for Wind/Unwind Tensioners

CCM Cost summary by fuel cell size

System Size (kW)	1			
Production Volume (Sys/yr)	100	1,000	10,000	50,000
Direct Material ($/m²)	743.36	605.23	521.39	468.77
Labor ($/m²)	1.59	0.50	0.41	0.40
Process: Capital ($/m²)	3689.50	389.45	39.35	7.95
Process: Operational ($/m²)	339.77	35.99	3.77	0.88
Process: Building ($/m²)	1608.36	169.77	17.16	3.47
Material Scrap ($/m²)	651.25	35.77	2.53	-1.23
Total ($/m²)	**7033.81**	**1236.70**	**584.60**	**480.24**

Table C. 7. CCM Cost analysis for 1kW CHP reformate fuel system

System Size (kW)	50			
Production Volume (Sys/yr)	100	1,000	10,000	50,000
Direct Material ($/m²)	543.38	468.80	401.68	356.24
Labor ($/m²)	0.40	0.40	0.39	0.20
Process: Capital ($/m²)	81.89	8.27	0.84	0.54
Process: Operational ($/m²)	7.67	0.91	0.22	0.12
Process: Building ($/m²)	35.70	3.61	0.36	0.11
Material Scrap ($/m²)	6.16	-1.22	-2.40	-1.66
Total ($/m²)	**675.19**	**480.77**	**401.10**	**355.55**

Table C. 8. CCM Cost analysis for 50kW CHP reformate fuel system

System Size (kW)	250			
Production Volume (Sys/yr)	100	1,000	10,000	50,000
Direct Material ($/m²)	491.10	422.33	358.46	317.85
Labor ($/m²)	0.40	0.39	0.20	0.20
Process: Capital ($/m²)	17.07	1.72	0.55	0.55
Process: Operational ($/m²)	1.71	0.30	0.12	0.12
Process: Building ($/m²)	7.44	0.75	0.12	0.12
Material Scrap ($/m²)	-0.11	-1.95	-1.63	-2.04
Total ($/m²)	**517.62**	**423.55**	**357.82**	**316.80**

Table C.9. CCM Cost analysis for 250kW CHP reformate fuel system

System Size (kW)	1			
Production Volume (Syst./yr)	100	1,000	10,000	50,000
Direct Material ($/kWe)	327.55	266.69	229.74	206.56
Labor ($/kWe)	0.70	0.22	0.18	0.17
Process: Capital ($/kWe)	1625.74	171.61	17.34	3.50
Process: Operational ($/kWe)	149.71	15.86	1.66	0.39
Process: Building ($/kWe)	708.71	74.81	7.56	1.53
Material Scrap ($/kWe)	286.97	15.76	1.12	-0.54
Total ($/kWe)	**3099.38**	**544.94**	**257.60**	**211.61**

Table C.10. CCM Cost analysis for 1kW CHP reformate fuel system in ($/kWe)

System Size (kW)	10			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/kWe)	259.24	223.40	192.57	172.17
Labor ($/kWe)	0.21	0.17	0.17	0.17
Process: Capital ($/kWe)	171.61	17.34	1.75	0.35
Process: Operational ($/kWe)	15.85	1.66	0.22	0.09
Process: Building ($/kWe)	74.81	7.56	0.76	0.15
Material Scrap ($/kWe)	15.73	1.13	-0.85	-1.02
Total ($/kWe)	**537.45**	**251.26**	**194.63**	**171.92**

Table C.11. CCM Cost analysis for 10kW CHP reformate fuel system in ($/kWe)

System Size (kW)	50			
Production Volume (Sys/yr)	100	1,000	10,000	50,000
Direct Material ($/kWe)	230.14	198.55	170.13	150.88
Labor ($/kWe)	0.17	0.17	0.17	0.08
Process: Capital ($/kWe)	34.68	3.50	0.35	0.23
Process: Operational ($/kWe)	3.25	0.38	0.09	0.05
Process: Building ($/kWe)	15.12	1.53	0.15	0.05
Material Scrap ($/kWe)	2.61	-0.51	-1.02	-0.70
Total ($/kWe)	**285.96**	**203.62**	**169.88**	**150.59**

Table C. 12. CCM Cost analysis for 50kW CHP reformate fuel system in ($/kWe)

System Size (kW)	100			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/kWe)	215.31	185.64	158.53	140.07
Labor ($/kWe)	0.16	0.16	0.16	0.08
Process: Capital ($/kWe)	17.34	1.75	0.18	0.23
Process: Operational ($/kWe)	1.65	0.22	0.08	0.05
Process: Building ($/kWe)	7.56	0.76	0.08	0.05
Material Scrap ($/kWe)	1.15	-0.80	-1.13	-0.75
Total ($/kWe)	**243.18**	**187.74**	**157.90**	**139.73**

Table C.13. CCM Cost analysis for 100kW CHP reformate fuel system in ($/kWe)

System Size (kW)	250			
Production Volume (Sys/yr)	100	1,000	10,000	50,000
Direct Material ($/kWe)	201.63	173.40	147.18	130.50
Labor ($/kWe)	0.16	0.16	0.08	0.08
Process: Capital ($/kWe)	7.01	0.71	0.23	0.23
Process: Operational ($/kWe)	0.70	0.12	0.05	0.05
Process: Building ($/kWe)	3.06	0.31	0.05	0.05
Material Scrap ($/kWe)	-0.05	-0.80	-0.67	-0.84
Total ($/kWe)	**212.52**	**173.90**	**146.91**	**130.07**

Table C.14. CCM Cost analysis for 250kW CHP reformate fuel system in ($/kWe)

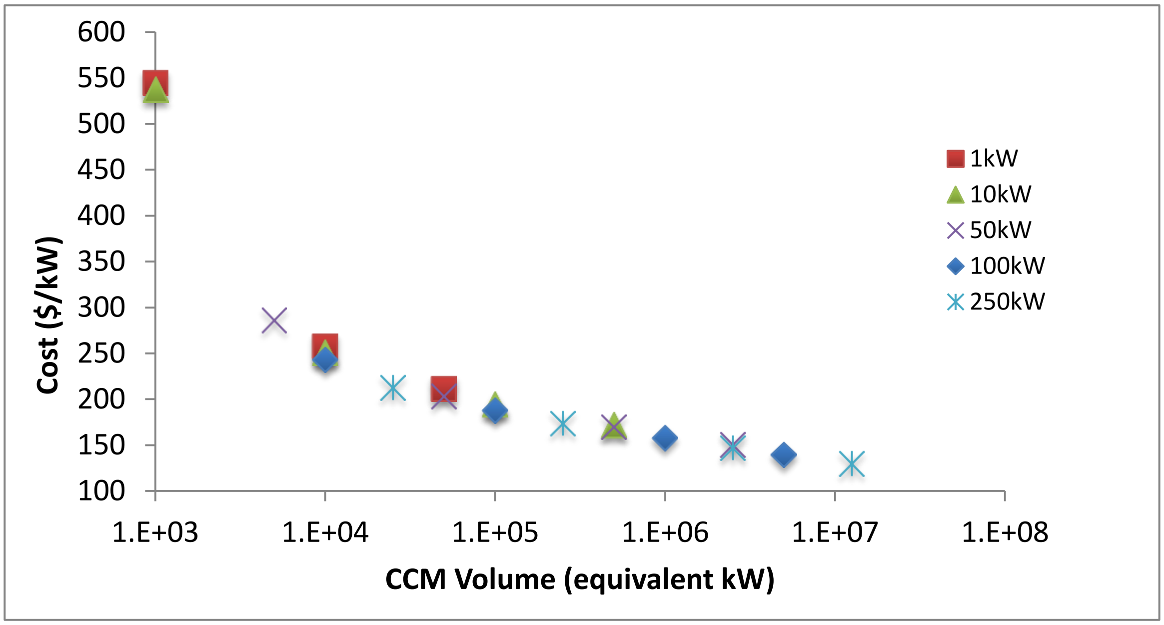
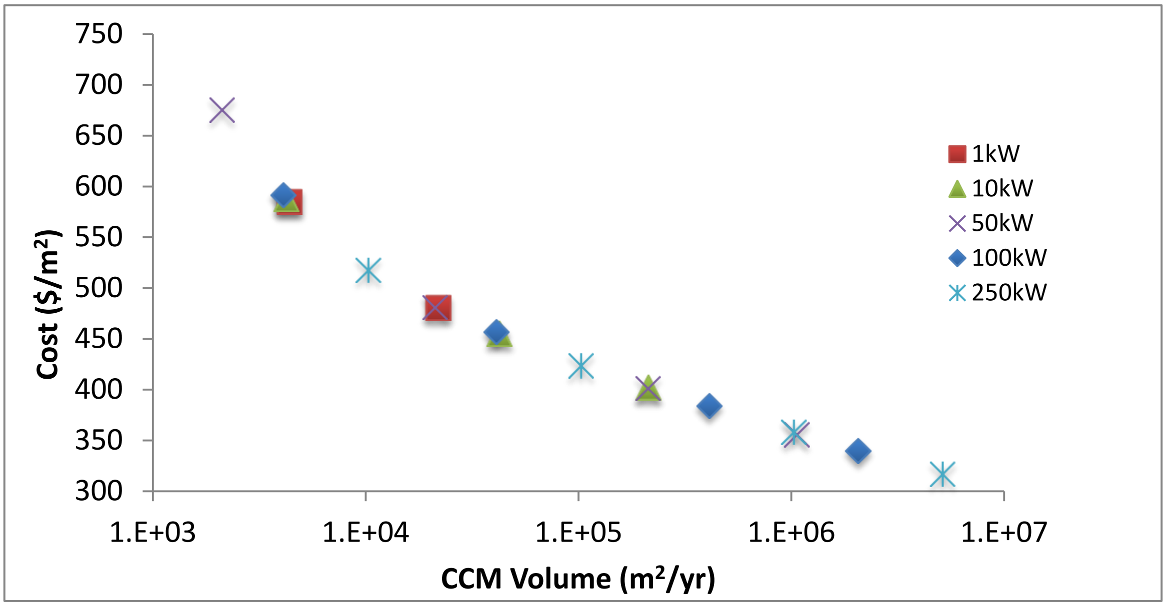


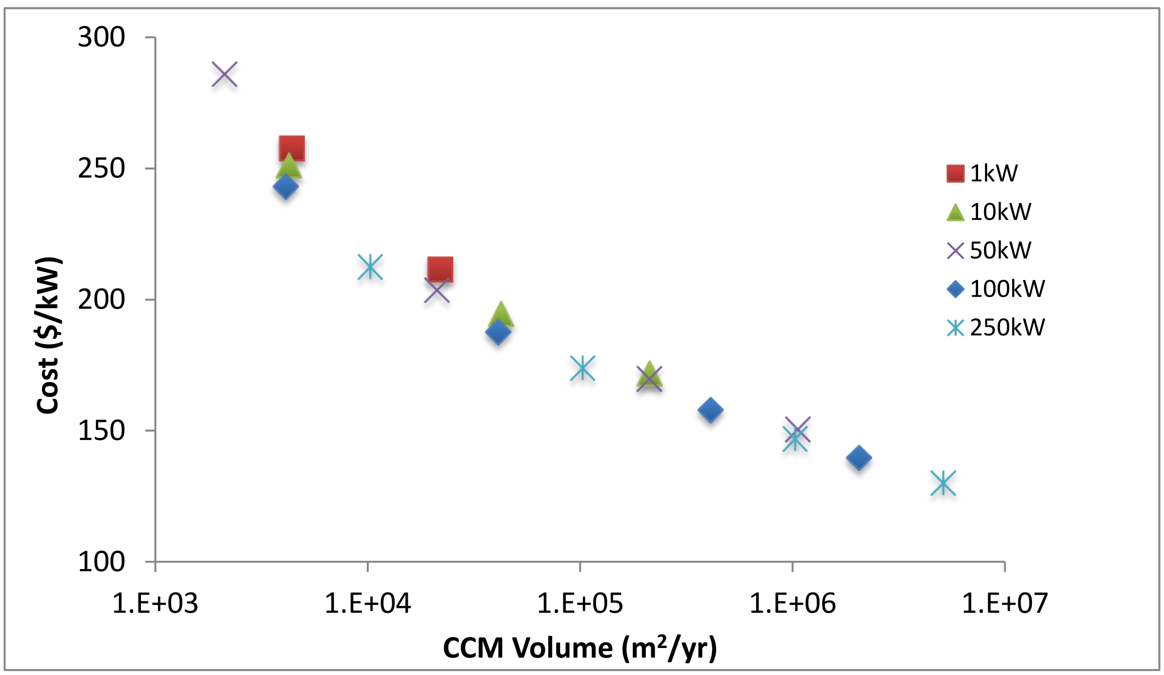
Figure C.2. CCM cost vs. production volume in ($/kWe)

CCM Results- Dual Coating Method (Double Side Coating System)

This approach was considered to quantify the impact of consolidating the CCM manufacturing process by depositing the cathode and anode layers at the same time. This process reduces the number of coating machines from 2 machines per coating line to 1 machine, as well as reducing drying units, and wind and unwind tensioners. Overall capital costs are lowered by about 33% across the board for all system sizes. However, since material costs are dominant above 1000 systems per year for system sizes above 10kW, there is a very little cost reduction for higher volumes. Note that this approach would also require re-engineering of ink materials and/or substrate materials to overcome swelling issues.



(a) cost in $/m² of the coated CCM



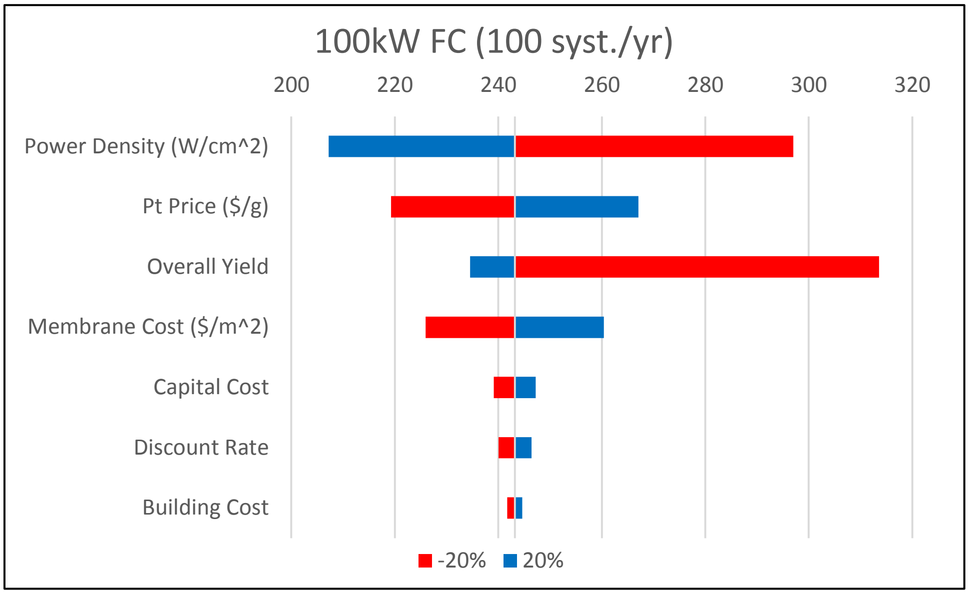
(b) cost in $/kWe of the coated CCM

Figure C.3. CCM cost vs. production volume for CHP reformate fuel cell using dual coating process: (a) cost in ($/m^2) of CCM; and (b) cost in ($/kWe)

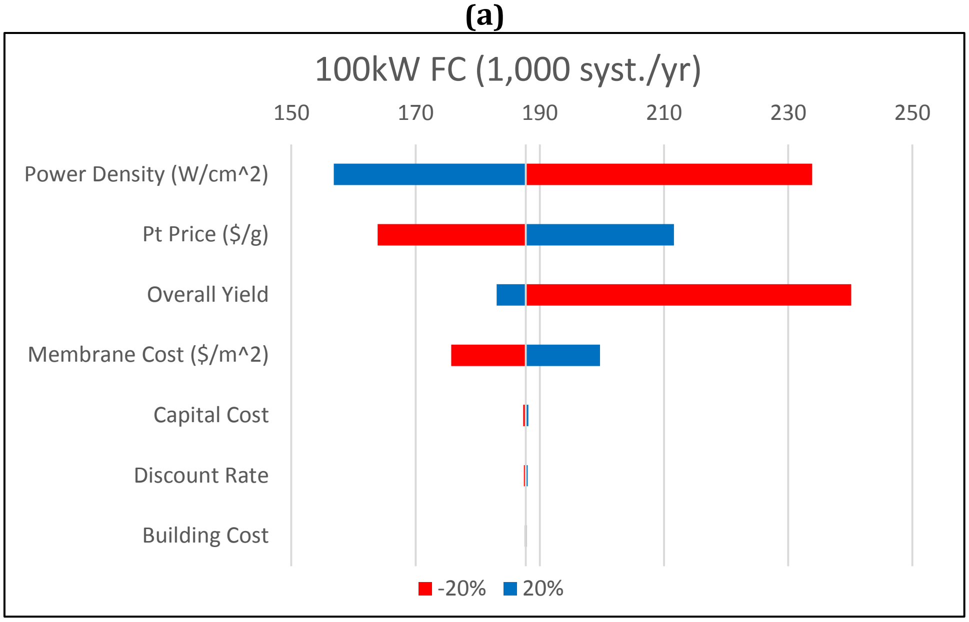
Sensitivity Analysis for CCM

Sensitivity analysis was done for 100kW systems at different production volumes (as shown below). The impact to CCM cost in $/kW for is calculated for a ±20% change in the sensitivity parameter being varied. While power density has the most significant effect on the overall CCM cost, Pt price has also large effect for all production volumes with a ±20% change in Pt prices resulting is a ±7% CCM cost at low volume, and ±18% CCM cost at high volume. Note that the Pt price variation can also be viewed as a proxy for varying Pt loading with the price held fixed.

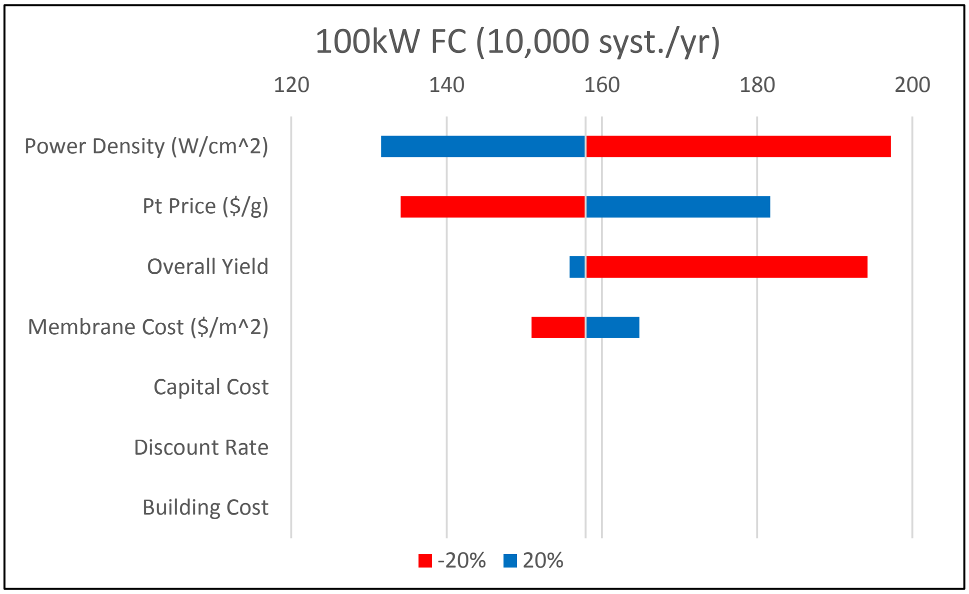
At low volume, membrane cost and overall yield are the next most important factors but membrane cost becomse less important at high volumes because membrane cost is expected to drop with higher volume. Discount rate not a large factor at high volume since material costs dominate. Note that yield becomes less sensitive at high volume for two reasons: (1) overall yield is assumed to be very high at high volume, and (2) material costs dominate at high volume and a significant portion of material costs are recovered from rejected material



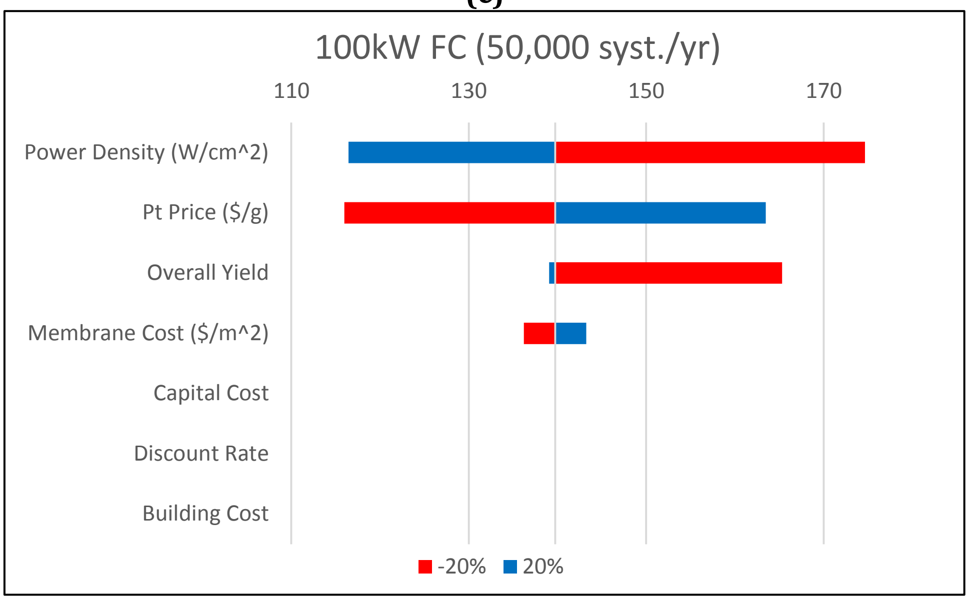
(a)



(b)



(c)



(d)

Figure C.4. CCM sensitivity analysis for 100 kW reformate fuel system expressed in ($/kW) at different annual production rates: (a) 100 systems/yr; (b) 1,000 systems/yr; (c) 10,000 systems /yr; and (d) 50,000 systems/yr.

Gas Diffusion Layer (GDL) Analysis

GDL Manufacturing

U.S. patent US 20090011308 A1, 2009, describes a representative GDL process flow. A GDL substrate, carbon fiber paper in this case, is impregnated in polytetrafluoroethylene (PTFE) solution followed by a drying step. Hydrophobic GDL materials are typically preferred in order to improve transport of product water away from the catalytic sites of the electrode and prevent flooding. Typically, the GDL is treated to increase the hydrophobicity by coating or impregnating with dispersions such as fluoropolymer, e.g, PTFE.

In addition, the upper surface may be finished with a coating that contains a dispersion of carbon particles (e.g. carbon black) and a fluoropolymer, typically to a thickness of 10-40 microns. This "micro-porous layer" (MPL) is found to further enhance water management by reducing the number of injection sites that allow water to diffuse from the catalyst layer to the gas diffusion layer. Furthermore, the carbon particles reduce the contact resistance between the catalyst electrode and the macro-porous layer. Subsequent to this, additional layers may be applied followed by further drying steps as required or necessitated by performance requirements for water management or uniformity. In the embodiment shown below (Fig. C.5) there is just one secondary coating for the MPL).

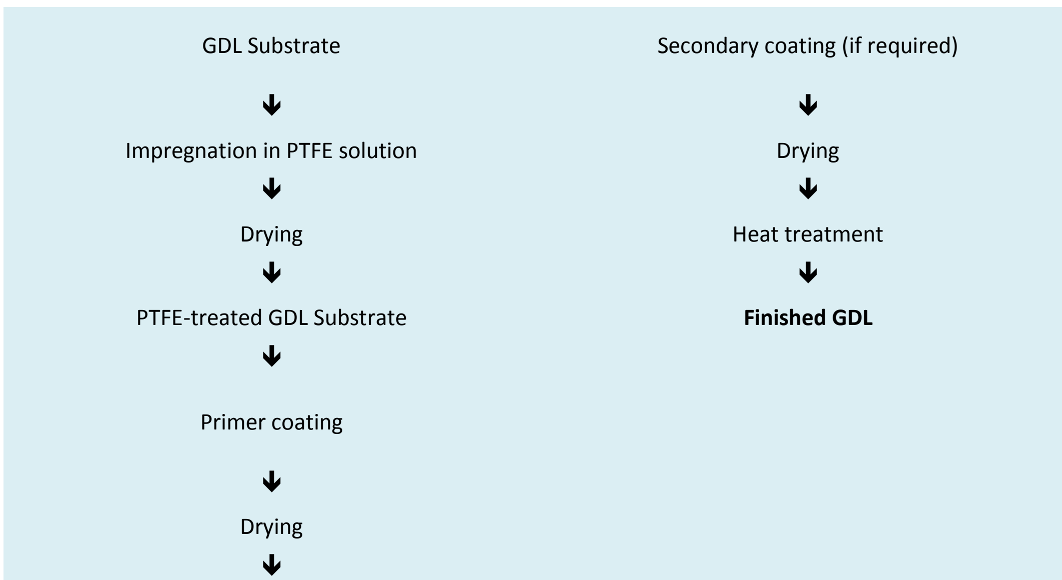


Figure C.5. General GDL process flow from U.S. patent US 20090011308 A1, 2009.

Process Parameters

The logic to determine the number of lines, line utilization, line width, and inspection type in the manufacturing flow is shown below.

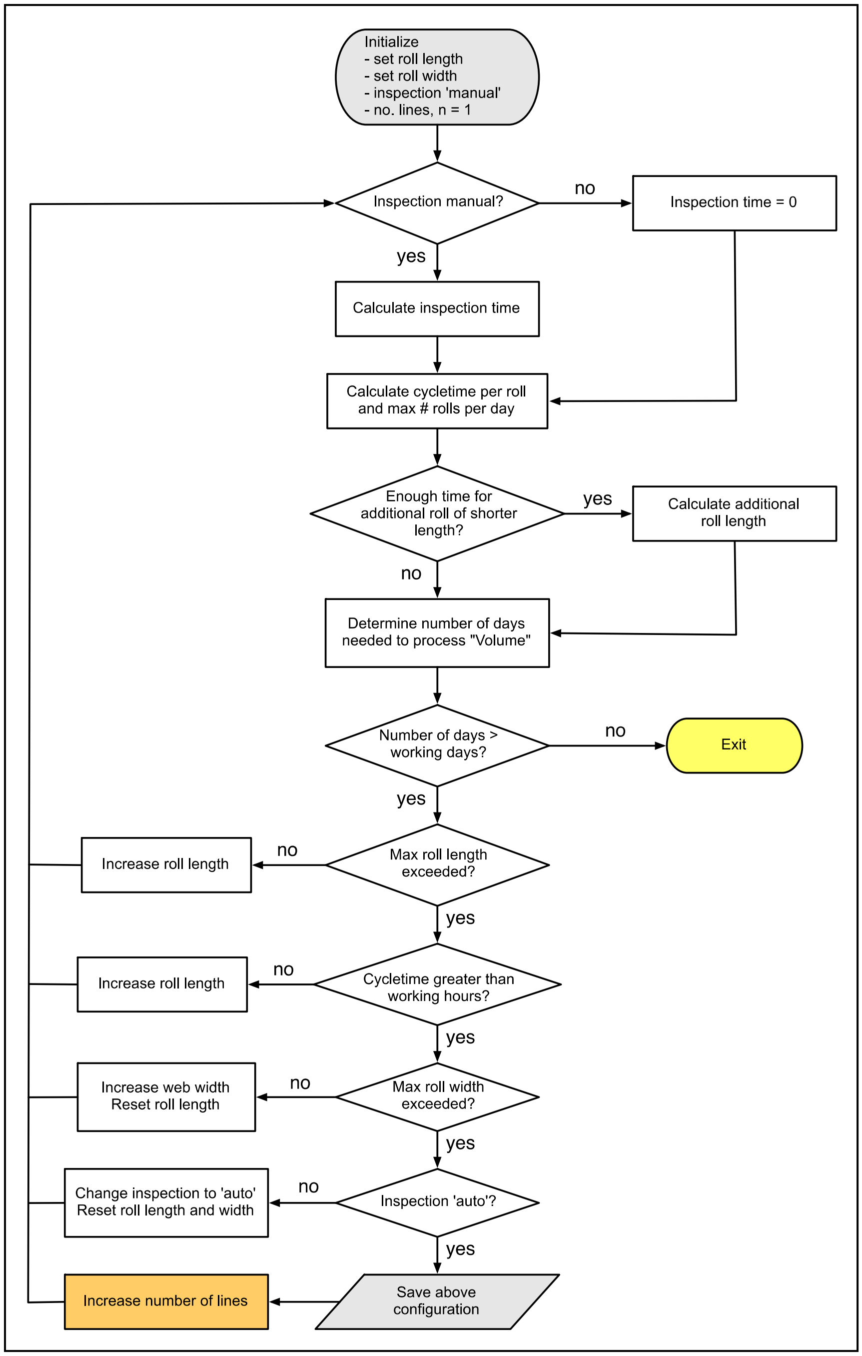


Figure C.6. Logic flow to determine the number of lines, line utilization, line width, and inspection type in the GDL manufacturing flow.

A pictorial depiction of the webline is shown in Figure C.7.

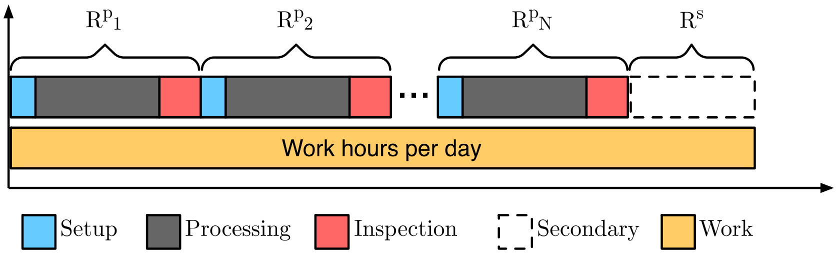


Figure C.7. Pictorial depiction of setup, processing and inspection for N rolls per day in the GDL process.

GDL Module Process Parameter Notes

<u>PTFE Solution Bath:</u>

- Cost analysis only includes the equipment cost and the actual PTFE usage and the energy to heat the bath. DI Water and filtration system are not included.
- Production is capped for each system size and volume; for example, the 1kW system at 100 systems per year is capped at 69.525 meters.
- Initial capital, installation costs (40% of capital cost), dwell time, maintenance factor, and power consumption (493kW) are derived from James et al., 2012.
- Machine footprint is based on web width, line speed, and dwell time.
- Salvage value is the amortized end-of-life value of the tool (counted as income).
- Property tax is proportional to the machine capital.
- Direct building costs are computed using the following: (no. lines) * (tool size [m^2]) * (cost per area [$/$m^2$]) * 2.8, where the 2.8 space correction factor is taken from (Verrey 2006). Cost is amortized with building depreciation and building life (31 years)

<u>Heat Treatment (IR Oven 1 & 2 & 3):</u>

- Assumes drying in atmospheric conditions with the cost associated with exhaust handling and treatment not included

<u>MPL Spray Deposition + Mixer:</u>

- Cost of DI water not included

<u>Wind & Unwind Tensioners:</u>

- Assume motorized unit to feed and control the web tension and manual loading and unloading of web

GDL Costing Model Results

System Size (kW)	1			
Production Volume (Sys/yr)	100	1,000	10,000	50,000
Direct Material ($/m^2)	145.99	119.94	93.90	75.69
Labor ($/m^2)	1.05	1.05	0.94	0.87
Process: Capital ($/m^2)	3199.19	319.92	31.99	6.40
Process: Operational ($/m^2)	228.66	23.00	2.42	0.59
Process: Building ($/m^2)	88.96	8.90	0.89	0.18
Material Scrap ($/m^2)	16.22	13.33	8.47	5.68
Total ($/m^2)	**3680.06**	**486.13**	**138.61**	**89.40**

Table C.15. GDL cost analysis for 1kW CHP system with reformate fuel

System Size (kW)	50			
Production Volume (Sys/yr)	100	1,000	10,000	50,000
Direct Material ($/m^2)	102.18	76.14	50.09	31.89
Labor ($/m^2)	0.98	0.87	0.39	0.36
Process: Capital ($/m^2)	66.57	6.66	0.71	0.57
Process: Operational ($/m^2)	4.89	0.60	0.18	0.54
Process: Building ($/m^2)	1.85	0.19	0.03	0.03
Material Scrap ($/m^2)	9.93	5.74	2.71	1.26
Total ($/m^2)	**186.41**	**90.20**	**54.11**	**34.64**

Table C.16. GDL cost analysis for 50kW CHP system with reformate fuel

System Size (kW)	250			
Production Volume (Sys/yr)	100	1,000	10,000	50,000
Direct Material ($/m^2)	84.33	58.29	32.24	14.04
Labor ($/m^2)	0.90	0.40	0.36	0.34
Process: Capital ($/m^2)	13.73	1.46	0.58	0.47
Process: Operational ($/m^2)	1.11	0.24	0.54	1.93
Process: Building ($/m^2)	0.38	0.07	0.03	0.02
Material Scrap ($/m^2)	6.93	3.54	1.28	0.35
Total ($/m^2)	**107.39**	**63.99**	**35.03**	**17.15**

Table C.17. GDL cost analysis for 250kW CHP system with reformate fuel

Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/kWe)	128.65	105.70	82.75	66.70
Labor ($/kWe)	0.93	0.93	0.83	0.76
Process: Capital ($/kWe)	2,819.38	281.94	28.19	5.64
Process: Operational ($/kWe)	201.51	20.27	2.13	0.52
Process: Building ($/kWe)	78.40	7.84	0.78	0.16
Material Scrap ($/kWe)	14.29	11.74	7.47	5.01
Total ($/kWe)	**3,243.17**	**428.42**	**122.15**	**78.79**

Table C.18 GDL Cost Analysis for 1 kW CHP System with reformate fuel ($/kW)

Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/kWe)	102.88	80.60	58.33	42.75
Labor ($/kWe)	0.90	0.81	0.72	0.33
Process: Capital ($/kWe)	281.94	28.19	2.82	0.60
Process: Operational ($/kWe)	20.26	2.13	0.31	0.16
Process: Building ($/kWe)	7.84	0.78	0.08	0.03
Material Scrap ($/kWe)	11.43	7.30	4.02	2.31
Total ($/kWe)	**425.26**	**119.81**	**66.27**	**46.18**

Table C.19 GDL Cost Analysis for 10 kW CHP System with reformate fuel ($/kW)

Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/kWe)	86.56	64.49	42.43	27.01
Labor ($/kWe)	0.83	0.74	0.33	0.31
Process: Capital ($/kWe)	56.39	5.64	0.60	0.48
Process: Operational ($/kWe)	4.15	0.51	0.15	0.46
Process: Building ($/kWe)	1.57	0.16	0.03	0.02
Material Scrap ($/kWe)	8.41	4.86	2.29	1.06
Total ($/kWe)	**157.90**	**76.40**	**45.84**	**29.34**

Table C.20 GDL Cost Analysis for 50 kW CHP System with reformate fuel ($/kW)

Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/kWe)	77.89	56.46	35.03	20.06
Labor ($/kWe)	0.78	0.69	0.31	0.29
Process: Capital ($/kWe)	28.19	2.82	0.60	0.42
Process: Operational ($/kWe)	2.13	0.30	0.26	0.73
Process: Building ($/kWe)	0.78	0.08	0.03	0.02
Material Scrap ($/kWe)	7.08	3.91	1.68	0.67
Total ($/kWe)	**116.85**	**64.26**	**37.91**	**22.18**

Table C.21 GDL Cost Analysis for 100 kW CHP System with reformate fuel ($/kW)

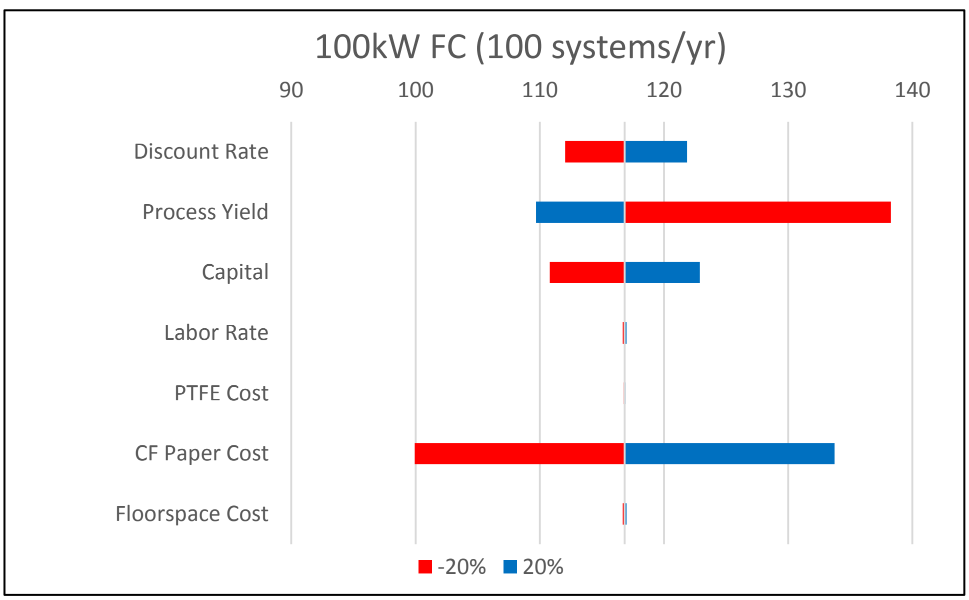
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/kWe)	69.25	47.86	26.47	11.53
Labor ($/kWe)	0.74	0.33	0.30	0.28
Process: Capital ($/kWe)	11.28	1.20	0.48	0.38
Process: Operational ($/kWe)	0.91	0.20	0.44	1.59
Process: Building ($/kWe)	0.31	0.06	0.02	0.02
Material Scrap ($/kWe)	5.69	2.91	1.05	0.29
Total ($/kWe)	**88.19**	**52.55**	**28.77**	**14.08**

Table C.22 GDL Cost Analysis for 250 kW CHP System with reformate fuel ($/kW)

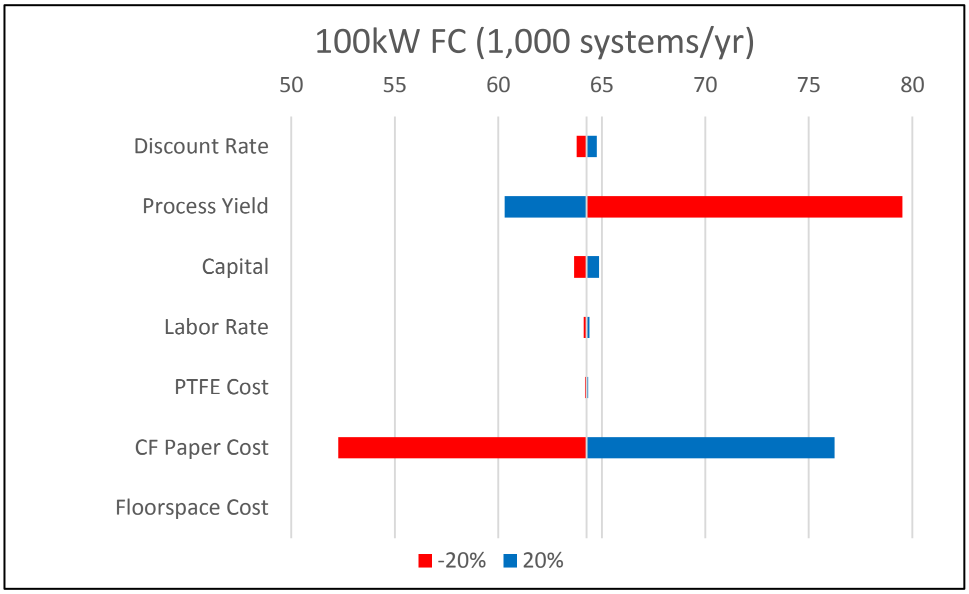
Sensitivity Analysis for GDL Cost

The following sensitivity analysis shows the effect of changing the global parameters on the total cost ($/kWe) of the fuel cell system. The red bars indicate a 20% increase for an individual parameter while the blue bars indicate a 20% decrease. A sensitivity analysis has been completed for the 10 kWe and 100 kWe systems.

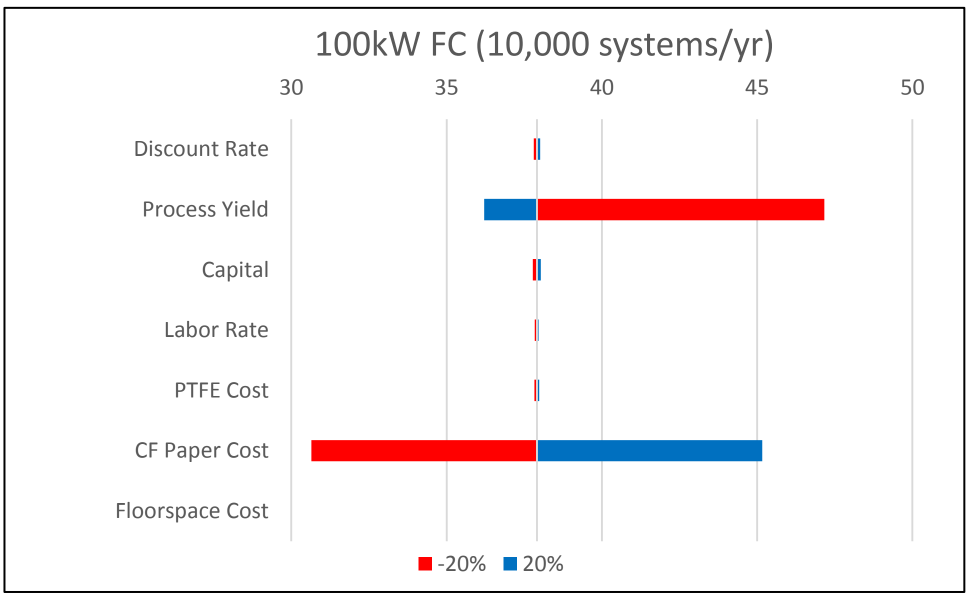
The sensitivity analysis for the 10kW system at 100 annual units shows that the GDL cost is most sensitive to changes in the discount rate, process yield, capital, and CF paper cost at low production rates. At higher quantities (100kW at 50,000 annual units), the process yield and CF paper cost are the most sensitive parameters. This shows that the capital cost is amortized to a smaller relative value at high production volumes. Figure C.8 shows the sensitivity analysis for the 100kW system.



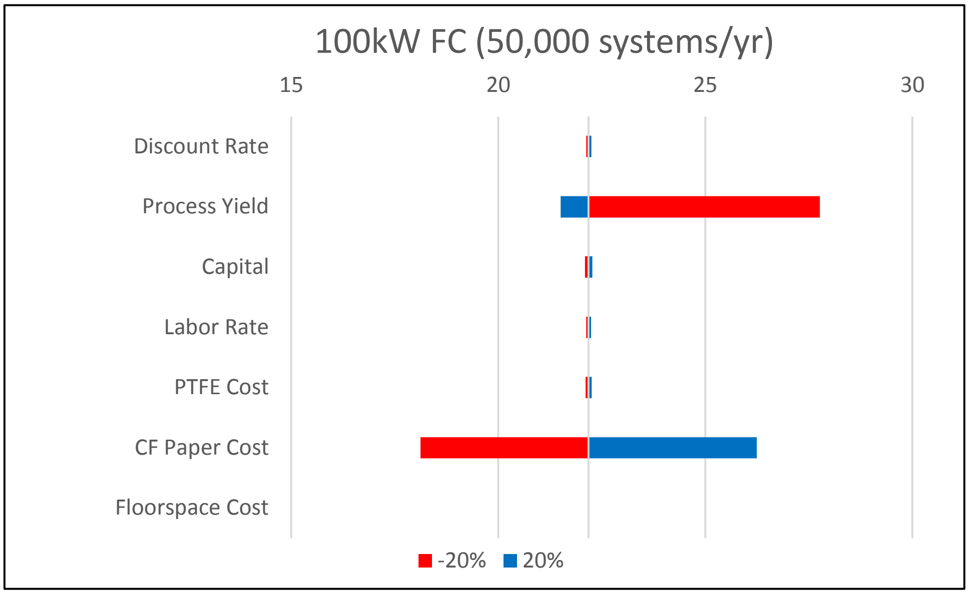
(a)


100kW FC (1,000 systems/yr)
50
55
60
65
70
75
80
Discount Rate
Process Yield
Capital
Labor Rate
PTFE Cost
CF Paper Cost
Floorspace Cost
-20%
20%

(b)


100kW FC (10,000 systems/yr)
30
35
40
45
50
Discount Rate
Process Yield
Capital
Labor Rate
PTFE Cost
CF Paper Cost
Floorspace Cost
-20%
20%

(c)



(d)

Figure C.8. GDL sensitivity analysis in ($/kW) for 100 kWe system (a) 100 systems/yr; (b) 1,000 systems/yr; (c) 10,000 systems/yr; and (d) 50,000 systems/yr.

MEA Frame/Seal

Frame Roll + Cutter:

Size (kW)	**100**			
Volume (Systems/yr)	100	1000	10000	50000
Configuration	B	B	B	B
No. of Tools	1	3	25	123
Cycle time (per MEA)	10	10	10	10
Power Consumption (kW)	7.5	7.5	7.5	7.5
Initial Capital ($)	9.63E+04	2.89E+05	2.41E+06	1.18E+07
Initial System Cost ($)	1.35E+05	4.04E+05	3.37E+06	1.66E+07
Depreciation ($/yr)	6.29E+03	1.89E+04	1.57E+05	7.74E+05
Amortized capital ($/yr)	1.99E+04	5.97E+04	4.97E+05	2.45E+06
Salvage Value ($/yr)	1.74E+02	5.22E+02	4.35E+03	2.14E+04
Property Tax ($/yr)	5.32E+02	1.59E+03	1.33E+04	6.54E+04
Maintenance Cost ($/yr)	1.42E+03	4.26E+03	3.55E+04	1.75E+05
Energy Cost ($/yr)	4.05E+02	3.97E+03	3.97E+04	1.99E+05
Machine Rate ($/hr)	**2.47E+01**	**7.86E+00**	**6.63E+00**	**6.53E+00**
Capital ($/hr)	2.27E+01	6.92E+00	5.77E+00	5.68E+00
Operational ($/hr)	2.04E+00	9.39E-01	8.58E-01	8.51E-01

*Includes cost of the roller load, cutter, and blank punch

Table C.23. Machine rates for frame roll and cutter

Robotic Arm:

Size (kW)	**100**			
Volume (Systems/yr)	100	1000	10000	50000
Configuration	B	B	B	B
No. of Tools	1	3	25	123
Cycle time (per MEA)	15	15	15	15
Power Consumption (kW)	15	15	15	15
Initial Capital ($)	9.10E+04	2.73E+05	2.27E+06	1.12E+07
Initial System Cost ($)	1.27E+05	3.82E+05	3.18E+06	1.57E+07
Depreciation ($/yr)	5.94E+03	1.78E+04	1.49E+05	7.31E+05
Amortized capital ($/yr)	1.88E+04	5.63E+04	4.70E+05	2.31E+06
Salvage Value ($/yr)	1.64E+02	4.93E+02	4.11E+03	2.02E+04
Property Tax ($/yr)	5.02E+02	1.51E+03	1.26E+04	6.18E+04
Maintenance Cost ($/yr)	1.34E+03	4.02E+03	3.35E+04	1.65E+05
Energy Cost ($/yr)	1.21E+03	1.19E+04	1.19E+05	5.96E+05
Machine Rate ($/hr)	**2.43E+01**	**8.36E+00**	**7.19E+00**	**7.10E+00**
Capital ($/hr)	2.14E+01	6.54E+00	5.45E+00	5.36E+00
Operational ($/hr)	2.86E+00	1.82E+00	1.74E+00	1.74E+00

Table C.24. Machine rates for robotic arm

7-axis Arm:

Size (kW)	**100**			
Volume (Systems/yr)	100	1000	10000	50000
Configuration	B	B	B	B
No. of Tools	1	3	25	123
Cycle time (per MEA)	20	20	20	20
Power Consumption (kW)	15	15	15	15
Initial Capital ($)	1.07E+05	3.21E+05	2.68E+06	1.32E+07
Initial System Cost ($)	1.50E+05	4.49E+05	3.75E+06	1.84E+07
Depreciation ($/yr)	6.99E+03	2.10E+04	1.75E+05	8.60E+05
Amortized capital ($/yr)	2.21E+04	6.63E+04	5.52E+05	2.72E+06
Salvage Value ($/yr)	1.93E+02	5.80E+02	4.83E+03	2.38E+04
Property Tax ($/yr)	5.91E+02	1.77E+03	1.48E+04	7.26E+04
Maintenance Cost ($/yr)	1.58E+03	4.73E+03	3.95E+04	1.94E+05
Energy Cost ($/yr)	1.62E+03	1.59E+04	1.59E+05	7.95E+05
Machine Rate ($/hr)	**2.87E+01**	**1.00E+01**	**8.67E+00**	**8.56E+00**

Capital ($/hr)	2.52E+01	7.69E+00	6.41E+00	6.31E+00
Operational ($/hr)	3.58E+00	2.35E+00	2.26E+00	2.25E+00

Table C.25. Machine rates for 7-axis arm

Hot Press (each):

Size (kW)	**100**			
Volume (Systems/yr)	100	1000	10000	50000
Configuration	B	B	B	B
No. of Tools	1	3	25	123
Cycle time (per MEA)	30	30	30	30
Power Consumption (kW)	17.5	17.5	17.5	17.5
Initial Capital ($)	2.14E+05	6.42E+05	5.35E+06	2.63E+07
Initial System Cost ($)	3.00E+05	8.99E+05	7.49E+06	3.69E+07
Depreciation ($/yr)	1.40E+04	4.19E+04	3.50E+05	1.72E+06
Amortized Capital ($/yr)	4.42E+04	1.33E+05	1.10E+06	5.44E+06
Salvage Value ($/yr)	3.87E+02	1.16E+03	9.66E+03	4.75E+04
Property Tax ($/yr)	2.83E+03	2.78E+04	2.78E+05	1.39E+06
Maintenance Cost ($/yr)	3.16E+03	9.47E+03	7.89E+04	3.88E+05
Energy Cost ($/yr)	2.83E+03	2.78E+04	2.78E+05	1.39E+06
Machine Rate ($/hr)	**5.70E+01**	**1.96E+01**	**1.69E+01**	**1.67E+01**
Capital ($/hr)	5.03E+01	1.54E+01	1.28E+01	1.26E+01
Operational ($/hr)	6.70E+00	4.25E+00	4.07E+00	4.06E+00

Table C.26. Machine rates for hot press used in MEA frame/seal manufacturing process

Final Blank Press:

Size (kW)	**100**			
Volume (Systems/yr)	100	1000	10000	50000
Configuration	B	B	B	B
No. of Tools	1	3	25	123
Cycle time (per MEA)	5	5	5	5
Power Consumption (kW)	10	10	10	10
Initial Capital ($)	5.35E+04	1.61E+05	1.34E+06	6.58E+06
Initial System Cost ($)	7.49E+04	2.25E+05	1.87E+06	9.21E+06
Depreciation ($/yr)	3.50E+03	1.05E+04	8.74E+04	4.30E+05
Amortized Capital ($/yr)	1.10E+04	3.31E+04	2.76E+05	1.36E+06
Salvage Value ($/yr)	9.66E+01	2.90E+02	2.42E+03	1.19E+04
Property Tax ($/yr)	2.95E+02	8.86E+02	7.38E+03	3.63E+04
Maintenance Cost ($/yr)	7.89E+02	2.37E+03	1.97E+04	9.71E+04

Energy Cost ($/yr)	2.70E+02	2.65E+03	2.65E+04	1.32E+05
Machine Rate ($/hr)	**1.38E+01**	**4.42E+00**	**3.73E+00**	**3.68E+00**
Capital ($/hr)	1.26E+01	3.85E+00	3.21E+00	3.15E+00
Operational ($/hr)	1.19E+00	5.72E-01	5.27E-01	5.23E-01

Table C.27. Machine rates for final blank press used in MEA frame/seal manufacturing process

MEA Tray Unloader:

Size (kW)	**100**			
Volume (Systems/yr)	100	1000	10000	50000
Configuration	B	B	B	B
No. of Tools	1	3	25	123
Cycle time (per MEA)	2	2	2	2
Power Consumption (kW)	2	2	2	2
Initial Capital ($)	1.61E+04	4.82E+04	4.01E+05	1.97E+06
Initial System Cost ($)	2.25E+04	6.74E+04	5.62E+05	2.76E+06
Depreciation ($/yr)	1.05E+03	3.15E+03	2.62E+04	1.29E+05
Amortized capital ($/yr)	3.31E+03	9.94E+03	8.29E+04	4.08E+05
Salvage Value ($/yr)	2.90E+01	8.70E+01	7.25E+02	3.57E+03
Property Tax ($/yr)	8.86E+01	2.66E+02	2.21E+03	1.09E+04
Maintenance Cost ($/yr)	2.37E+02	7.10E+02	5.92E+03	2.91E+04
Energy Cost ($/yr)	2.16E+01	2.12E+02	2.12E+03	1.06E+04
Machine Rate ($/hr)	**4.06E+00**	**1.26E+00**	**1.05E+00**	**1.04E+00**
Capital ($/hr)	3.78E+00	1.15E+00	9.62E-01	9.46E-01
Operational ($/hr)	2.89E-01	1.05E-01	9.16E-02	9.05E-02

Table C.28. Machine rates for MEA tray unloader

Cost Summary for MEA

Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/Part)	0.53	0.53	0.53	0.53
Labor ($/Part)	0.46	0.45	0.17	0.17
Process: Capital ($/Part)	86.13	8.57	0.97	0.38
Process: Operational ($/Part)	6.09	0.65	0.11	0.07
Process: Building ($/Part)	6.77	0.67	0.07	0.03
Material Scrap ($/Part)	9.79	1.83	0.95	0.86
Total ($/Part)	**109.77**	**12.70**	**2.80**	**2.04**

Table C.29. MEA frame/seal cost analysis for 1kW CHP system with reformate fuel.

Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/Part)	0.53	0.53	0.53	0.53
Labor ($/Part)	0.44	0.17	0.17	0.17
Process: Capital ($/Part)	1.76	0.40	0.26	0.25
Process: Operational ($/Part)	0.17	0.07	0.06	0.06
Process: Building ($/Part)	0.14	0.03	0.02	0.02
Material Scrap ($/Part)	1.04	0.86	0.85	0.84
Total ($/Part)	**4.07**	**2.05**	**1.88**	**1.87**

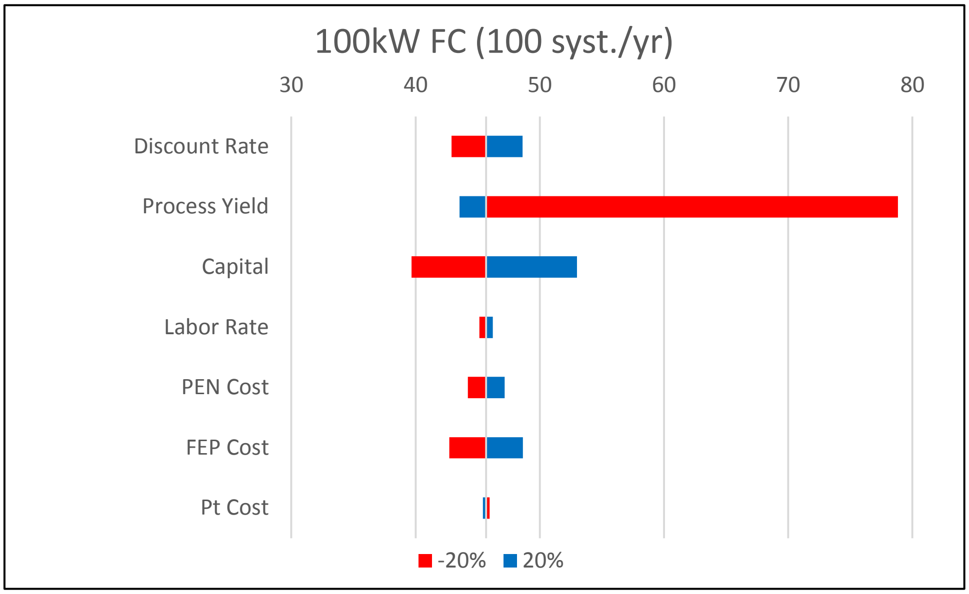
Table C.30. MEA frame/seal cost analysis for 50kW CHP system with reformate fuel.

Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/Part)	0.53	0.53	0.53	0.53
Labor ($/Part)	0.17	0.17	0.17	0.17
Process: Capital ($/Part)	0.41	0.29	0.25	0.25
Process: Operational ($/Part)	0.07	0.06	0.06	0.06
Process: Building ($/Part)	0.03	0.02	0.02	0.02
Material Scrap ($/Part)	0.88	0.85	0.84	0.84
Total ($/Part)	**2.10**	**1.91**	**1.87**	**1.86**

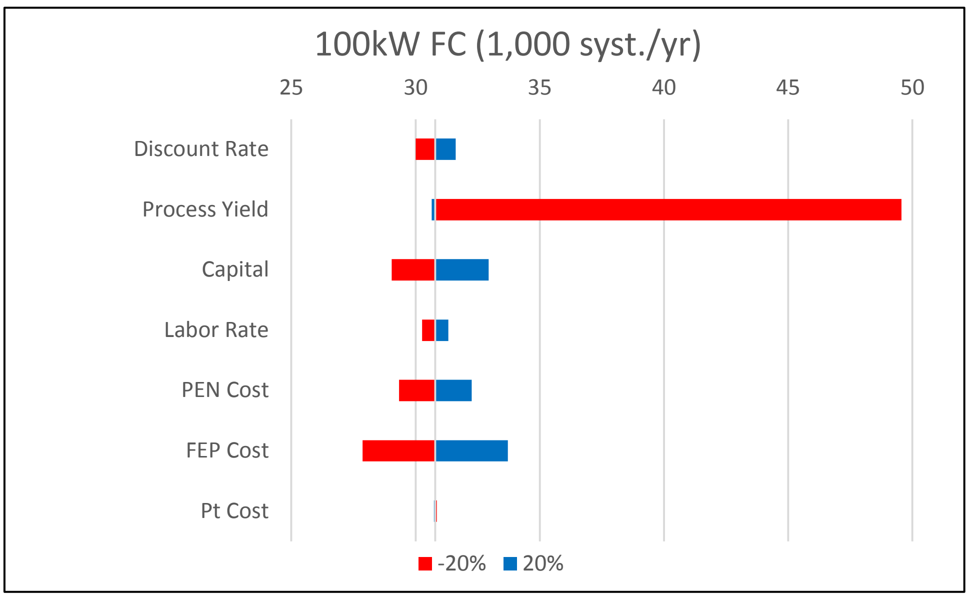
Table C.31. MEA frame/seal cost analysis for 250kW CHP system with reformate fuel.

Sensitivity Analysis for MEA Frame/Seal

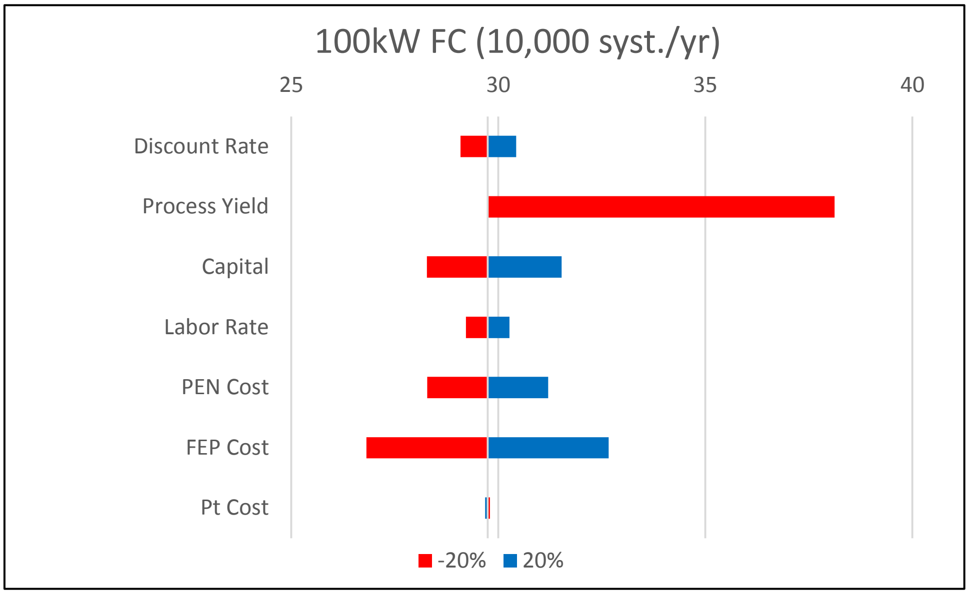
Sensitivity analysis for a 100kW CHP system is shown below. At low volume, the process yield is by far the most sensitive parameter. The positive increase (+20%) of the process yield is not as sensitive as the negative (-20%) since yield is capped to a maximum of 100% and therefore a full 20% increase is not observed. At high volume, both the process yield and material costs are the most sensitive factors.


100kW FC (100 syst./yr)
30
40
50
60
70
80
Discount Rate
Process Yield
Capital
Labor Rate
PEN Cost
FEP Cost
Pt Cost
-20%
20%

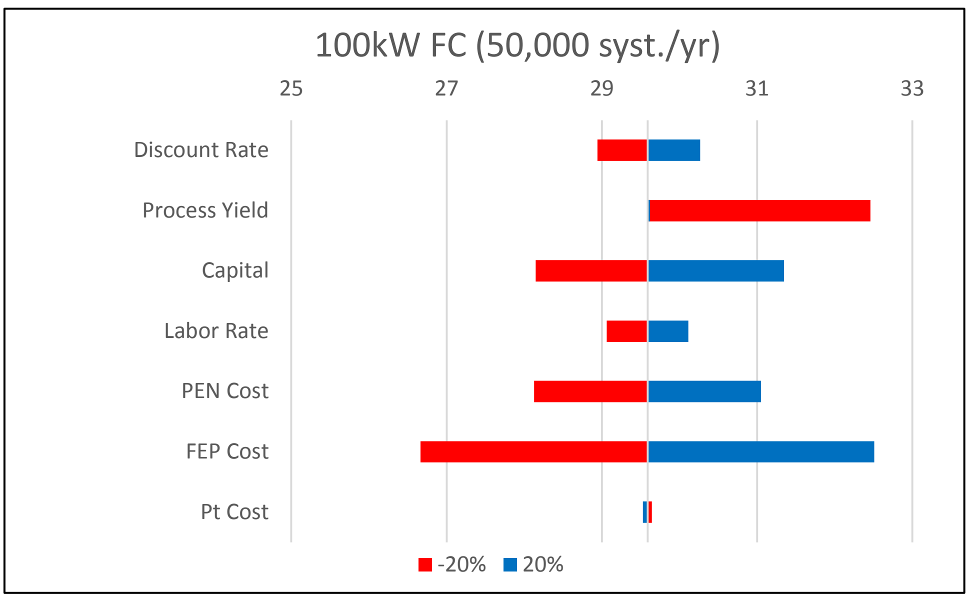
(a)


100kW FC (1,000 syst./yr)
25
30
35
40
45
50
Discount Rate
Process Yield
Capital
Labor Rate
PEN Cost
FEP Cost
Pt Cost
-20%
20%

(b)



(c)



(d)

Figure C.9. Frame sensitivity analysis for 100 kW CHP system with reformate fuel expressed in ($/kW) at different annual production rates: (a) 100 systems/yr; (b) 1,000 systems/yr; (c) 10,000 systems/yr; and (d) 50,000 systems/yr.

Metal Plates

Labor Requirements:

- Number of shifts: 1, 1.5, or 2, depending on volume.
- Determine the necessary number of lines starting with 1 shift.
- If the number of lines is greater than 1, increase number of shifts.

- Continue until max number of shifts has been reached (2).
- If the number of shifts reaches a max, increase the number of lines by one and reset the shift size to 1
- Repeat until the line utilization is less than one
- Number of workers:
  - Configuration A: 3 * number of lines
  - Configuration B: 2 * Ceiling (number of lines /2) + 1

System Size (kW)	**1**			
Production Volume (Syst./yr)	100	1,000	10,000	50,000
Direct Material	0.80	0.80	0.77	0.73
Labor	0.77	0.77	0.72	0.38
Process: Capital	613.01	61.30	6.13	1.60
Process: Operational	61.87	6.69	1.15	0.59
Process: Building	15.50	1.55	0.16	0.04
Material Scrap	0.14	0.14	0.10	0.05
Total ($/BIP)	**692.09**	**71.26**	**9.02**	**3.38**

Table C.32. Costing summary of metal plates for a 1kW CHP system with reformate fuel.

System Size (kW)	**50**			
Production Volume (Syst./yr)	100	1,000	10,000	50,000
Direct Material	0.79	0.73	0.68	0.68
Labor	0.75	0.38	0.17	0.12
Process: Capital	12.76	1.66	0.83	0.80
Process: Operational	1.83	0.59	0.48	0.48
Process: Building	0.32	0.04	0.02	0.02
Material Scrap	0.12	0.05	0.00	0.00
Total ($/BIP)	**16.57**	**3.46**	**2.19**	**2.11**

Table C.33. Costing summary of metal plates for a 50kW CHP system with reformate fuel.

System Size (kW)	**250**			
Production Volume (Syst./yr)	100	1,000	10,000	50,000
Direct Material	0.75	0.69	0.68	0.68
Labor	0.69	0.20	0.12	0.12
Process: Capital	2.63	1.03	0.82	0.80
Process: Operational	0.79	0.51	0.48	0.48
Process: Building	0.07	0.03	0.02	0.02
Material Scrap	0.07	0.01	0.00	0.00
Total ($/BIP)	**4.99**	**2.46**	**2.14**	**2.10**

Table C.34. Costing summary of metal plates for a 250kW CHP system with reformate fuel.

Equivalent costing summary tables expressed in $/kWe are shown below.

System Size (kW)	10			
Production Volume (Syst./yr)	100	1,000	10,000	50,000
Direct Material	13.21	12.69	11.73	11.29
Labor	12.71	11.86	3.07	2.74
Process: Capital	1042.12	104.21	27.19	13.60
Process: Operational	113.52	19.36	9.58	7.96
Process: Building	26.36	2.64	0.69	0.34
Material Scrap	2.33	1.64	0.51	0.06
Total ($/kWe)	**1210.25**	**152.39**	**52.76**	**35.99**

Table C.35. Costing summary in ($/kWe) of metal plates for a 10kW CHP system with reformate fuel.

System Size (kW)	100			
Production Volume (Sys/yr)	100	1,000	10,000	50,000
Direct Material	12.22	11.29	10.86	10.86
Labor	11.43	2.95	2.07	1.97
Process: Capital	104.21	27.19	13.60	12.78
Process: Operational	19.03	9.32	7.71	7.63
Process: Building	2.64	0.69	0.34	0.32
Material Scrap	1.60	0.51	0.05	0.05
Total ($/kWe)	**151.12**	**51.96**	**34.64**	**33.61**

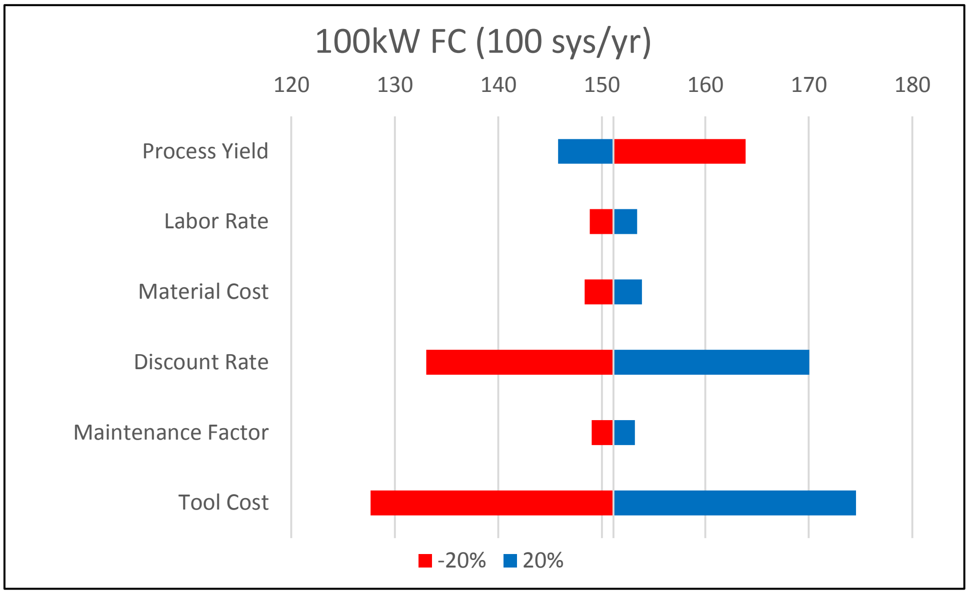
Table C.36. Costing summary in ($/kWe) of metal plates for 100kW CHP system with reformate fuel.

Sensitivity Analysis for Metal Plate

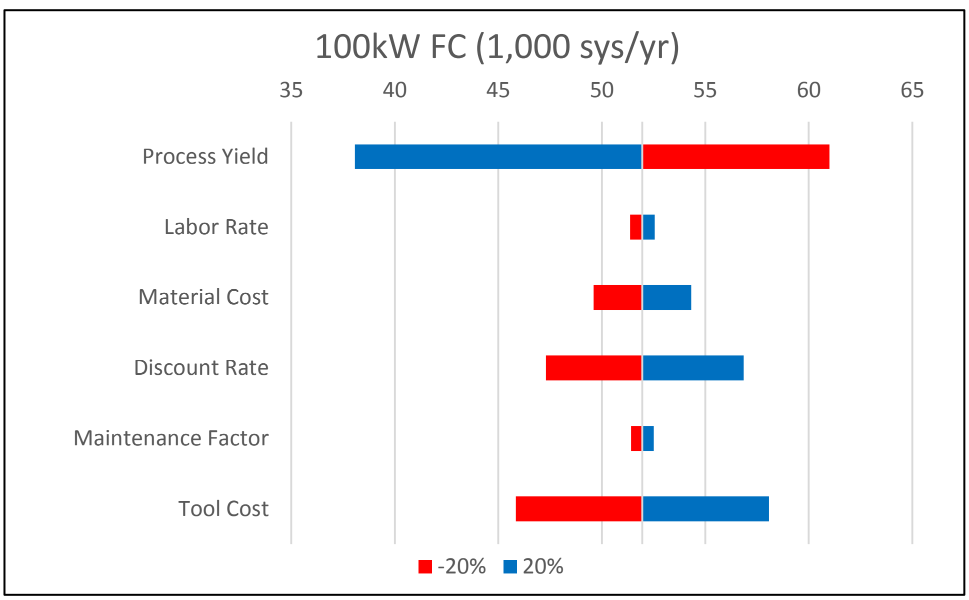
Figure C.10 shows sensitivity analyses for the 100kWe system at 100, 1000, 10000, and 50000 systems produced per year. For low volumes of the 100kWe system, it is seen that the discount rate, process yield, and tool cost are the most sensitive parameters. This corresponds to the fact that capital cost drives the cost in low production volumes.

At higher quantities (100kWe and 10,000 annual units), process yield becomes the most sensitive parameter, thus meaning that the manufacturing cost is process driven. The change from highly sensitive capital parameters to those related to process is observed due to the fact that at higher quantities, capital costs are spread out over a greater amount of systems.

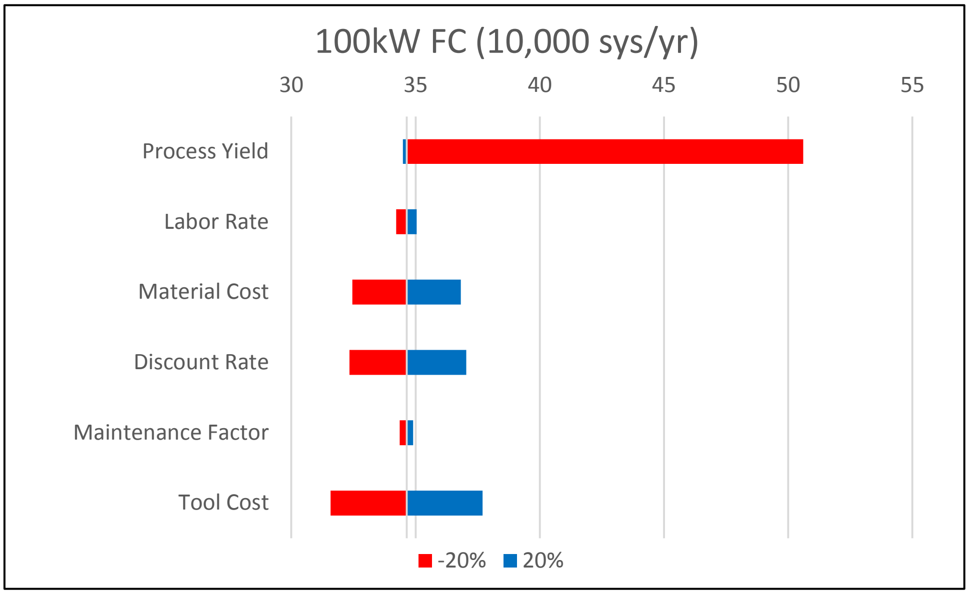
At the highest quantity for the 100 kWe case (50,000 annual units), the process parameters are still highly sensitive, however, there is now a large sensitivity in regards to materials. The material parameters are now just as sensitive as the discount rate and tool cost. This is because material cost per unit is not dependent on the amount of units produced while the sensitivity of capital cost and process parameters are reduced with annual production volume.



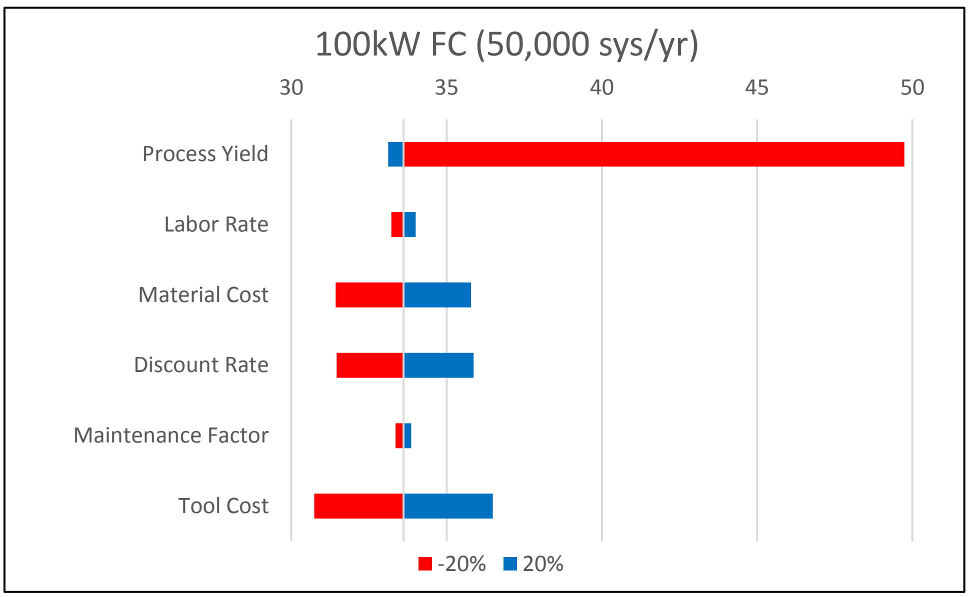
(a)



(b)



(c)



(d)

Figure C.10. Metal BIP sensitivity analysis for 100 kW CHP system with reformate fuel expressed in ($/kW) at different annual production volumes: (a) 100 systems/yr; (b) 1,000 systems/yr; (c) 10,000 systems/yr; and (d) 50,000 annual systems

Carbon Plates

Process parameters are shown in the following table.

Size (kW)	Production Volume	Half-Plates (x1000)	Config.	No. Workers	Work hours (production)	Line Yield
1	100	3.4	A	4	48.17	60%
	1000	34	B	5	253.4	60%
	10000	340	B	5	2216	68.63%
	50000	1700	B	9	9283	81.90%
10	100	33	B	5	246	60%
	1000	330	B	5	2157	68.41%
	10000	3300	B	13	16750	88.09%
	50000	16500	B	45	74160	99.50%
50	100	163.4	B	5	1154	63.32%
	1000	1634	B	9	8961	81.55%
	10000	16340	B	45	73440	99.50%
	50000	81700	B	217	367200	99.50%
100	100	317.4	B	5	2084	68.12%
	1000	3174	B	13	16180	87.72%
	10000	31740	B	85	142700	99.50%
	50000	158700	B	421	713300	99.50%
250	100	792	B	9	4703	75.31%
	1000	7920	B	25	36520	96.98%
	10000	79200	B	213	356000	99.50%
	50000	396000	B	1049	1780000	99.50%

Table C.37. Process parameter for composite plate manufacturing line

Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/BPP)	2.10	2.10	1.83	1.54
Labor ($/BPP)	3.59	2.36	1.00	0.74
Process: Capital ($/BPP)	92.43	17.13	3.43	1.37
Process: Operational ($/BPP)	6.80	1.50	0.48	0.30
Process: Building ($/BPP)	2.34	0.43	0.09	0.03
Material Scrap ($/BPP)	1.40	1.40	0.84	0.34
Total ($/BPP)	**108.66**	**24.91**	**7.67**	**4.32**

Table C.38. Costing summary of carbon plates for 1kW CHP system with reformate fuel.

Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/BPP)	1.99	1.54	1.26	1.26
Labor ($/BPP)	2.21	0.75	0.55	0.54
Process: Capital ($/BPP)	3.56	1.43	0.78	0.77
Process: Operational ($/BPP)	0.51	0.30	0.22	0.22
Process: Building ($/BPP)	0.09	0.04	0.02	0.02
Material Scrap ($/BPP)	1.15	0.35	0.01	0.01
Total ($/BPP)	**9.51**	**4.40**	**2.85**	**2.82**

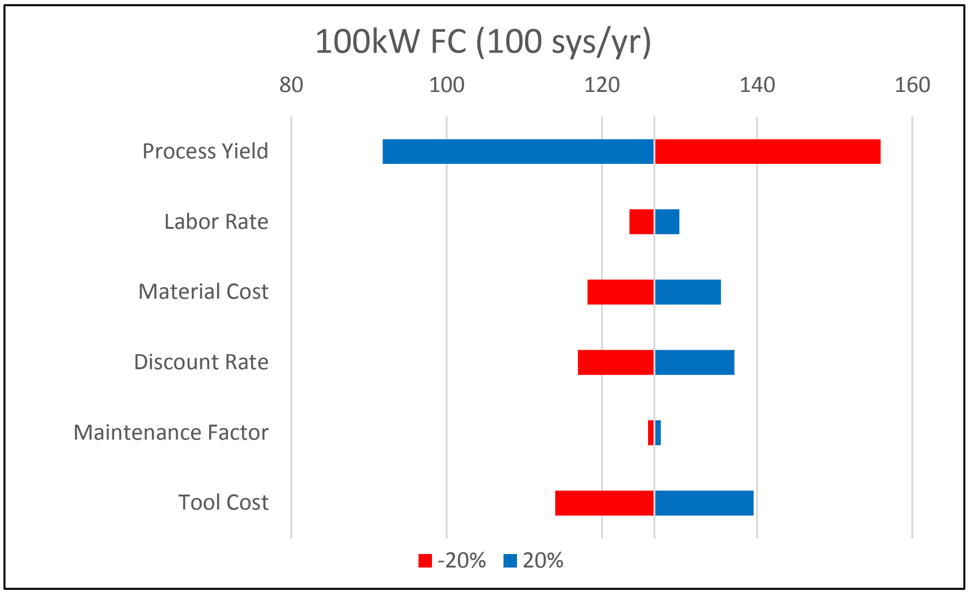
Table C.39. Costing summary of carbon plates for 50kW CHP system with reformate fuel.

Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/BPP)	1.67	1.30	1.26	1.26
Labor ($/BPP)	1.08	0.58	0.55	0.54
Process: Capital ($/BPP)	2.21	0.88	0.77	0.77
Process: Operational ($/BPP)	0.38	0.23	0.22	0.22
Process: Building ($/BPP)	0.06	0.02	0.02	0.02
Material Scrap ($/BPP)	0.55	0.04	0.01	0.01
Total ($/BPP)	**5.94**	**3.05**	**2.83**	**2.82**

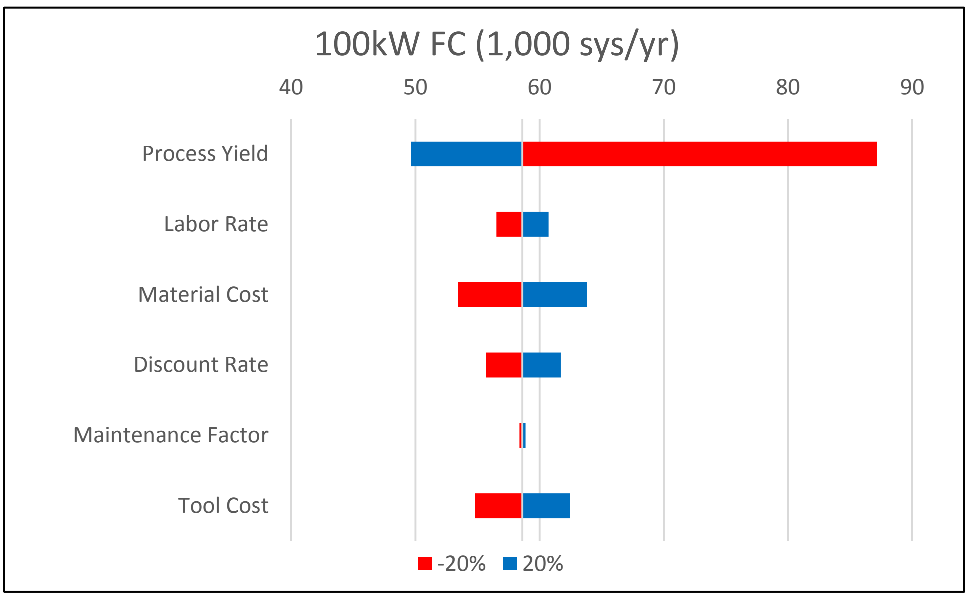
Table C.40. Costing summary of carbon plates for 250kW CHP system with reformate fuel.

Sensitivity Analysis for Carbon Plate

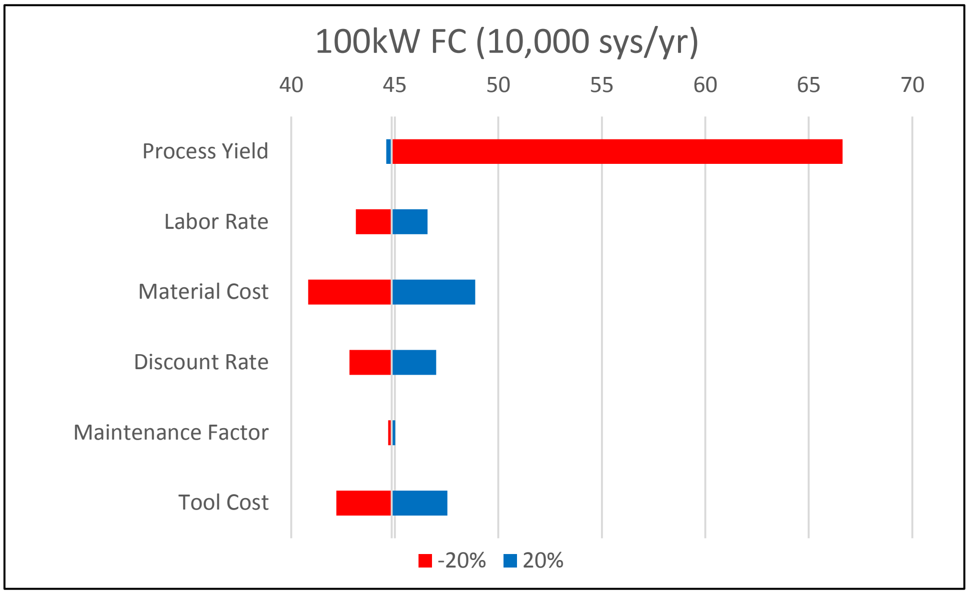
Sensitivity analysis (Figure C.11) shows that the carbon plates are highly sensitive to changing process yield, tool cost and discount rate at low production volumes (100kW, 100 systems/year). The process yield has the greatest effect on the total cost at higher quantities (100kW at 50,000 systems/year). A positive increase in tool cost, maintenance factor, discount rate, material cost, and labor rate directly increase the cost of the carbon plates. However, process yield is inversely related to the overall cost.


100kW FC (100 sys/yr)
80
100
120
140
160
Process Yield
Labor Rate
Material Cost
Discount Rate
Maintenance Factor
Tool Cost
-20%
20%

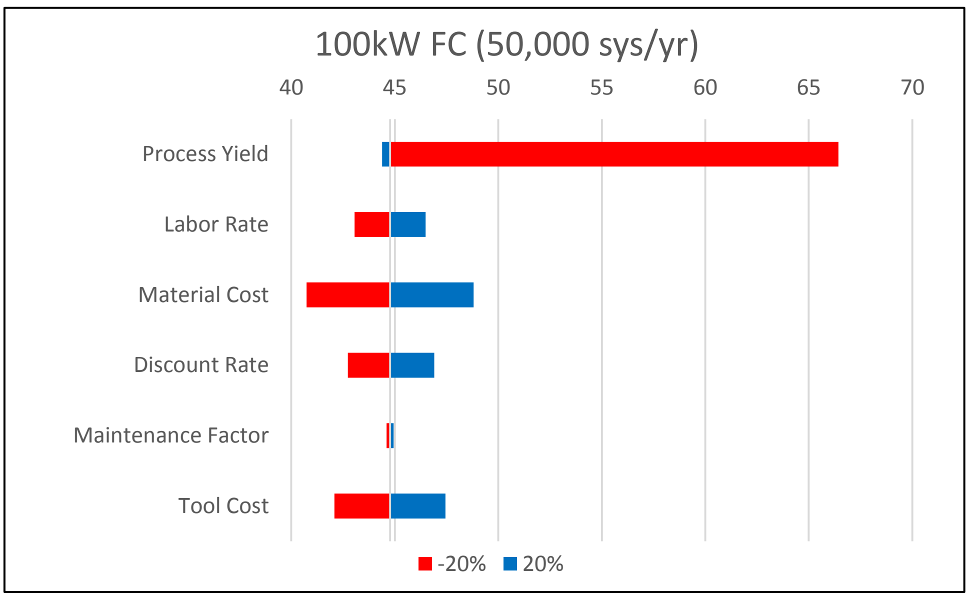
(a)


100kW FC (1,000 sys/yr)
40
50
60
70
80
90
Process Yield
Labor Rate
Material Cost
Discount Rate
Maintenance Factor
Tool Cost
-20%
20%

(b)



(c)



(d)

Figure C.11. Carbon BIP sensitivity analysis for 100 kW CHP system with reformate fuel. expressed in ($/kW) at different annual production volumes: a) 100 Sys/yr; b) 1,000 unit/yr; c) 10,000 Sys/yr; and d) 50,000 Sys/yr

Assembly Line Calculations

Conditioning and Testing Assumptions

Conditioning and Testing (programmable load bank) for 100kW FC system				
Systems/Yr	100	1000	10000	50000
Simultaneous lines	1	1	1	5
Maintenance factor	0.1	0.1	0.1	0.1
Auxiliary Costs Factor	0	0	0	0
Power Consumption (kW)	34	34	34	170
Conditioning Time (hr)	3	3	3	3
Machine Footprint (m^2)	168	168	168	336
Initial Capital (from DTI report, 2010)	430000	430000	430000	1575000
Initial System Cost	473000	473000	473000	1732500
Depreciation Rate	28093.33	28093.33	28093.33	102900
Annual Cap Payment	69766.19	69766.19	69766.19	255538.97
Auxiliary Costs	0	0	0	0
Maintenance	6342.38	6342.38	6342.38	23230.82
Salvage Value	776.62	776.62	776.62	2844.61
Energy Costs	1219.79	12197.91	121979.07	1219790.73
Property Tax	2373.6	2373.6	2373.6	8694
Building Costs	7.29E+04	7.29E+04	7.29E+04	3.65E+05
Interest Tax Deduction	0	0	0	0
Depreciation	0	0	0	0
Machine Rate ($/hour)	**506.18**	**54.28**	**9.09**	**8.39**
Capital	229.97	23	2.3	1.68
Variable	25.21	6.18	4.28	4.220841197
Building	250.9975103	25.09975103	2.509975103	2.488815103

Table C.41. Machine rates for conditioning and testing module (100kW system)

Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/kWe)	207.14	166.73	134.41	121.48
Labor ($/kWe)	99.37	99.37	49.68	8.83
Process: Capital ($/kWe)	415.69	41.57	17.16	6.61
Process: Operational ($/kWe)	39.41	5.02	3.62	1.32
Process: Building ($/kWe)	1,156.07	115.61	16.34	3.35
Material Scrap ($/kWe)	0.00	0.00	0.00	0.00
Total ($/kWe)	**1,917.67**	**428.29**	**221.21**	**141.60**

Table C.42. Cost analysis of stack assembly for 1kW CHP system with reformate fuel.

Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/kWe)	4.45	3.73	3.14	2.92
Labor ($/kWe)	1.99	0.99	0.18	0.18
Process: Capital ($/kWe)	8.31	3.62	0.33	0.13
Process: Operational ($/kWe)	0.85	0.41	0.04	0.03
Process: Building ($/kWe)	23.12	2.00	0.17	0.07
Material Scrap ($/kWe)	0.00	0.00	0.00	0.00
Total ($/kWe)	**38.73**	**10.75**	**3.86**	**3.32**

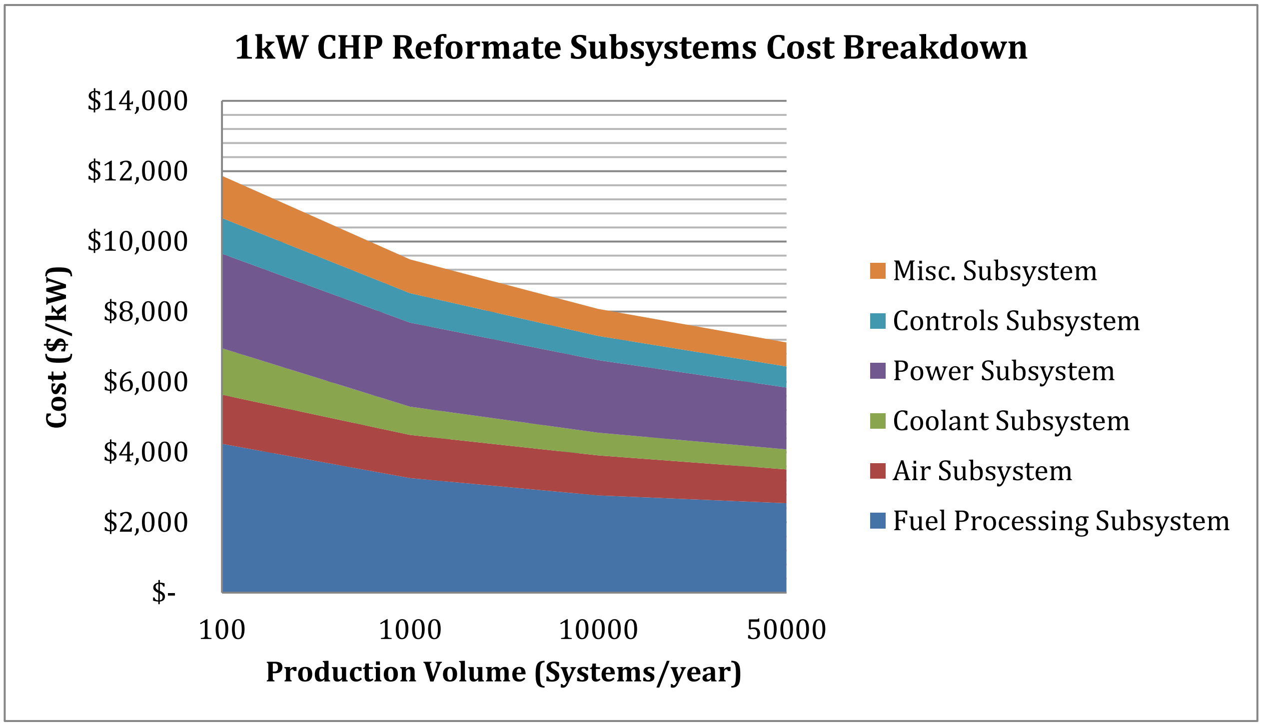
Table C.43. Cost analysis of stack assembly for 50kW CHP system with reformate fuel

Production Volume (Systems/yr)	100	1,000	10,000	50,000
Direct Material ($/kWe)	1.42	1.30	1.30	1.16
Labor ($/kWe)	0.20	0.04	0.04	0.04
Process: Capital ($/kWe)	4.01	0.66	0.07	0.03
Process: Operational ($/kWe)	0.41	0.07	0.01	0.01
Process: Building ($/kWe)	3.89	0.33	0.03	0.01
Material Scrap ($/kWe)	0.00	0.00	0.00	0.00
Total ($/kWe)	**9.93**	**2.40**	**1.45**	**1.25**

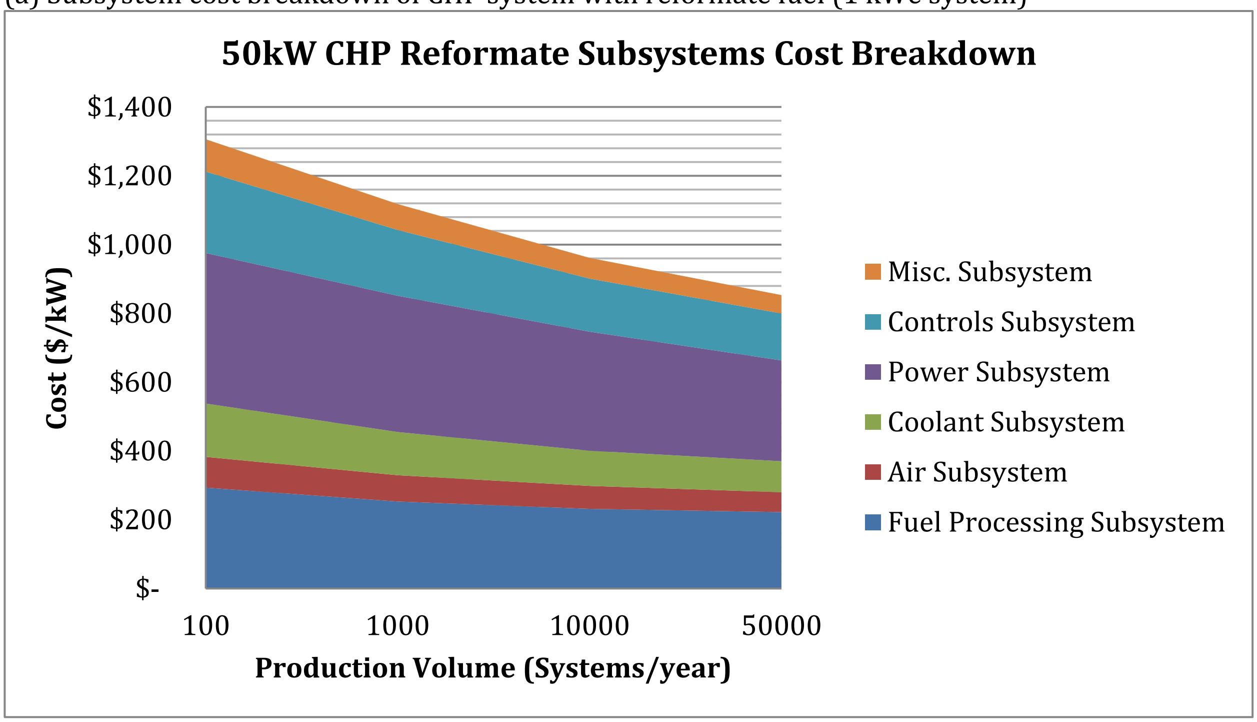
Table C.44. Cost analysis of stack assembly for 250kW CHP system with reformate fuel

Appendix D: Balance of Plant Costing for CHP and Backup Power Systems

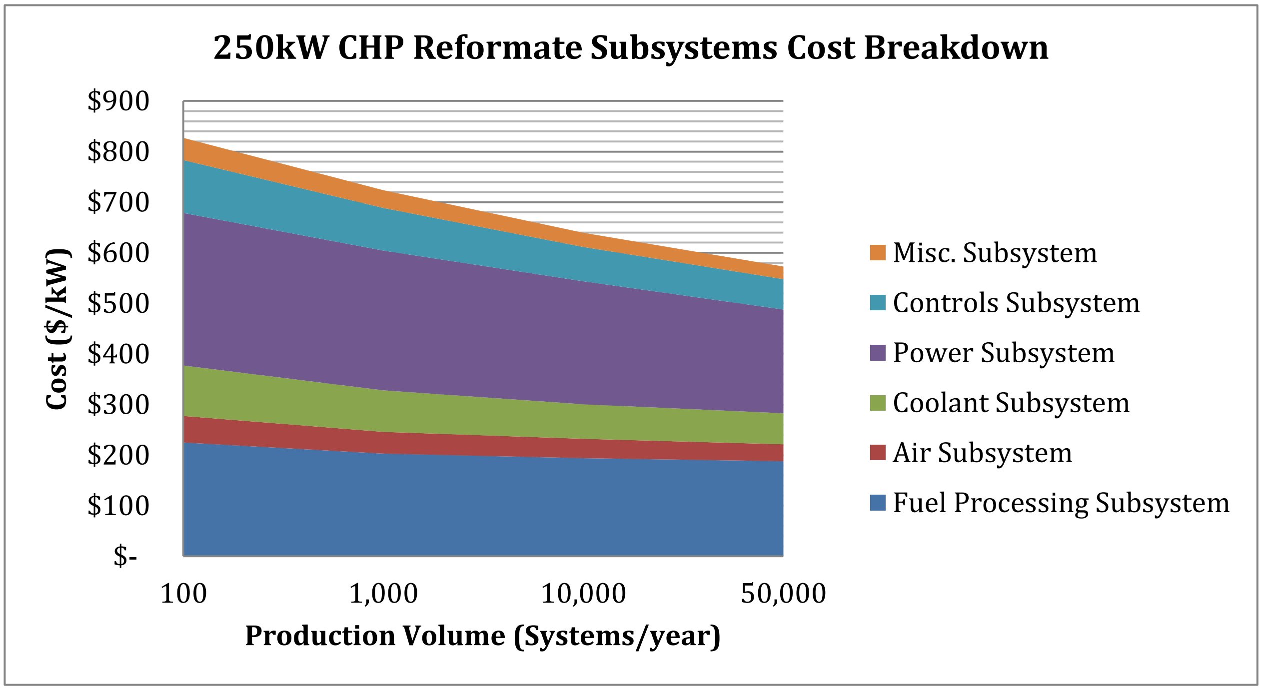
CHP Reformate



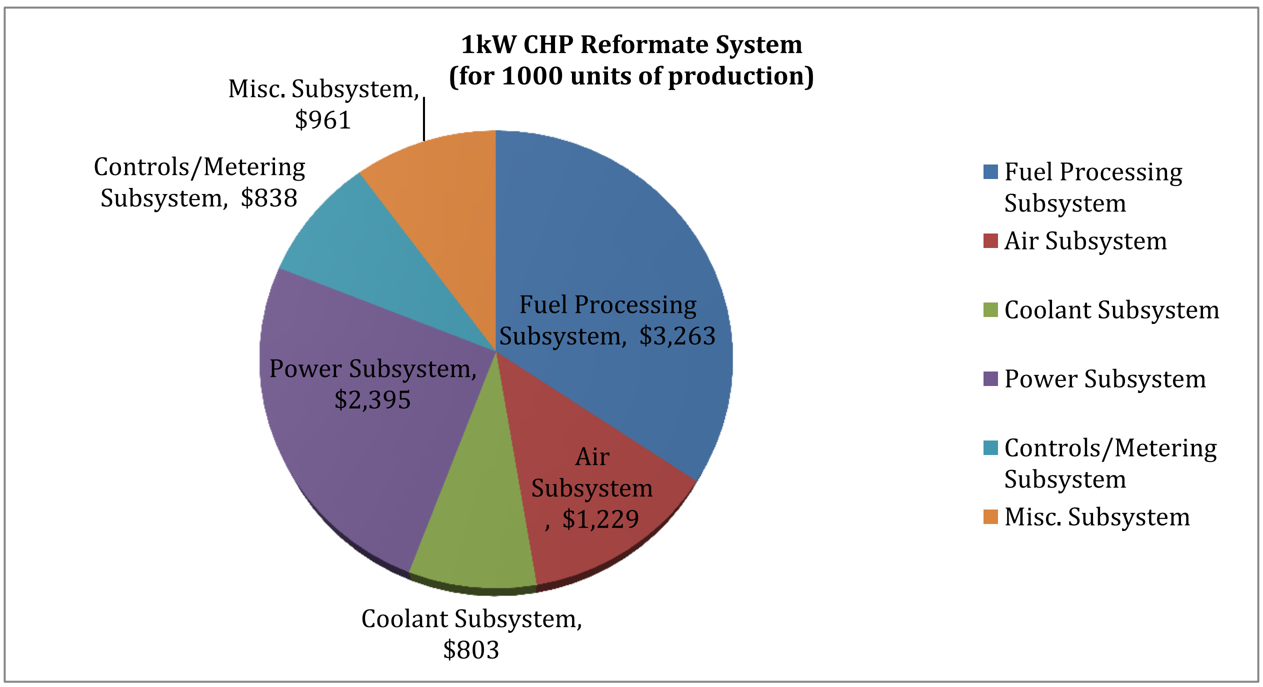
(a) Subsystem cost breakdown of CHP system with reformate fuel (1 kWe system)



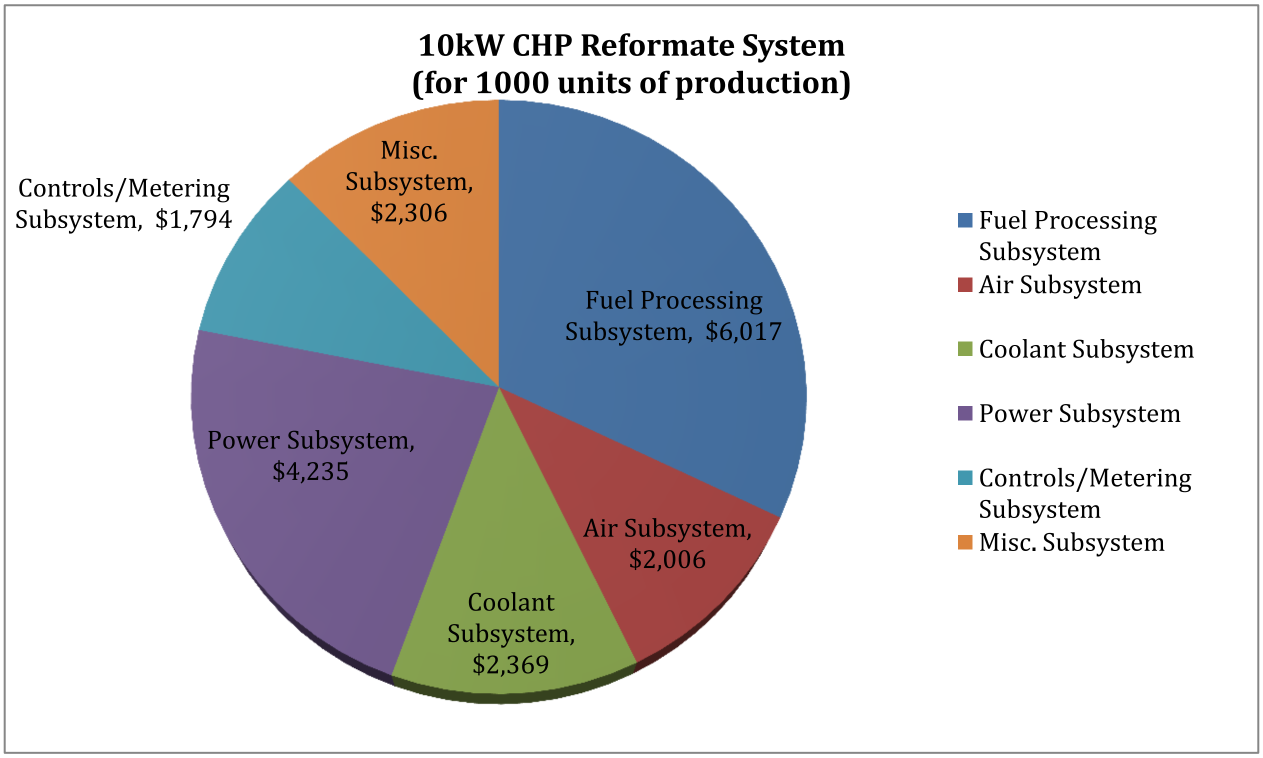
(b) Subsystem cost breakdown of CHP system with reformate fuel (50 kWe system)



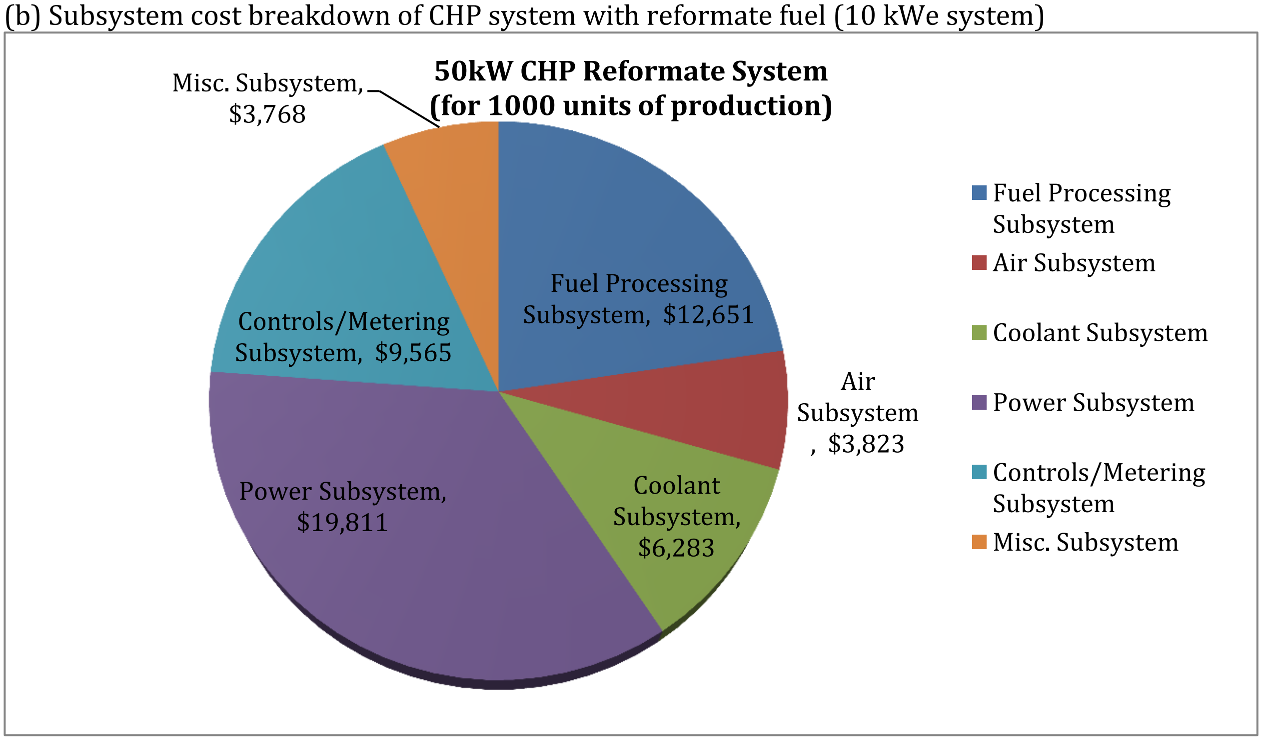
(c) Subsystem cost breakdown of CHP system with reformate fuel (250 kWe system)
Figure D.1. Subsystem cost breakdown of CHP system with reformate fuel for (a) 1 kWe system; (b) 50 kWe system; (c) 250 kWe system



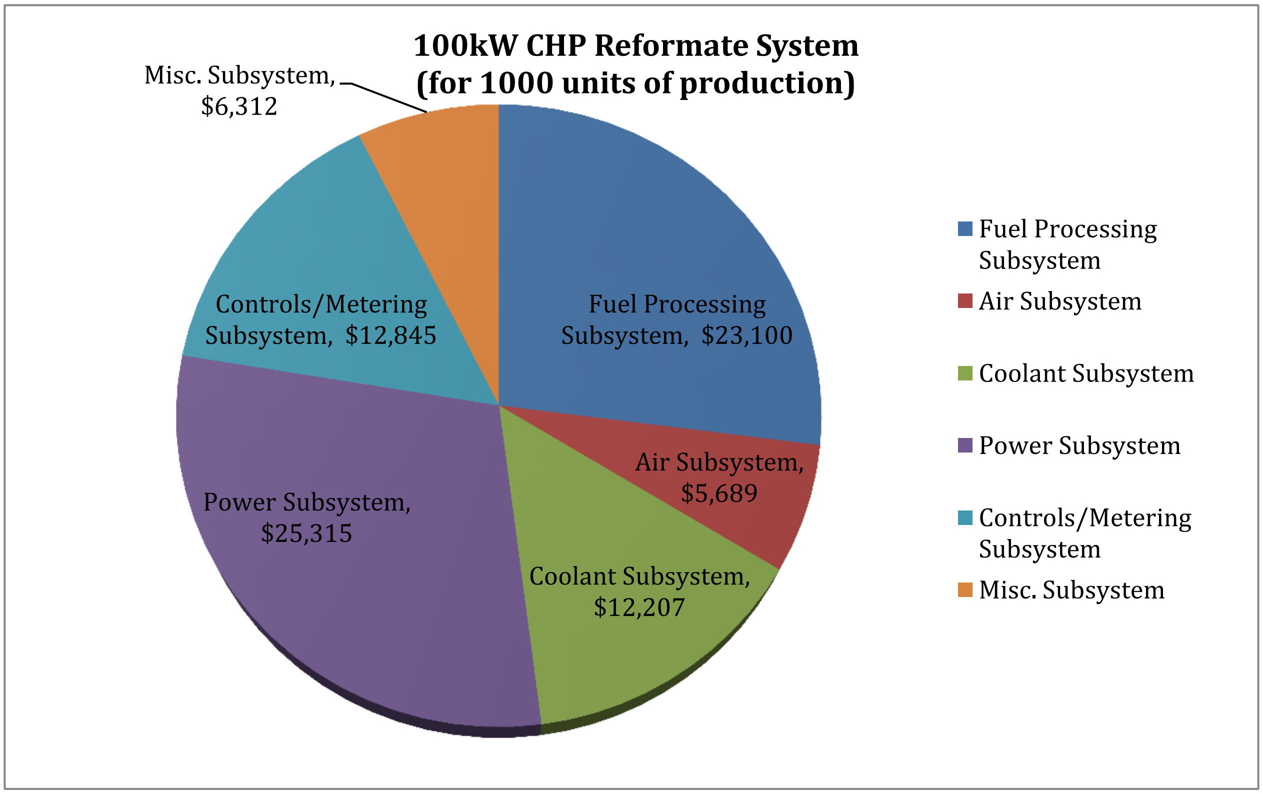
(a) Subsystem cost breakdown of CHP system with reformate fuel (1 kWe system)



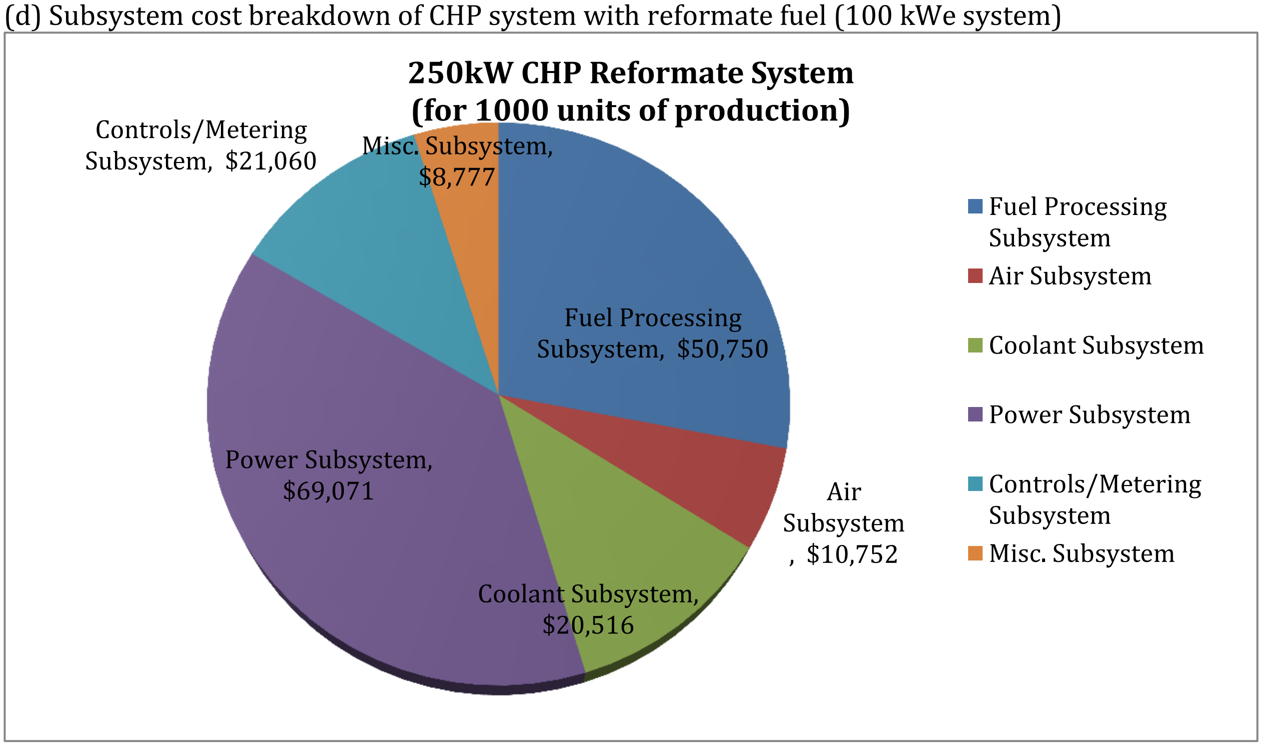
(b) Subsystem cost breakdown of CHP system with reformate fuel (10 kWe system)



(c) Subsystem cost breakdown of CHP system with reformate fuel (50 kWe system)



(d) Subsystem cost breakdown of CHP system with reformate fuel (100 kWe system)

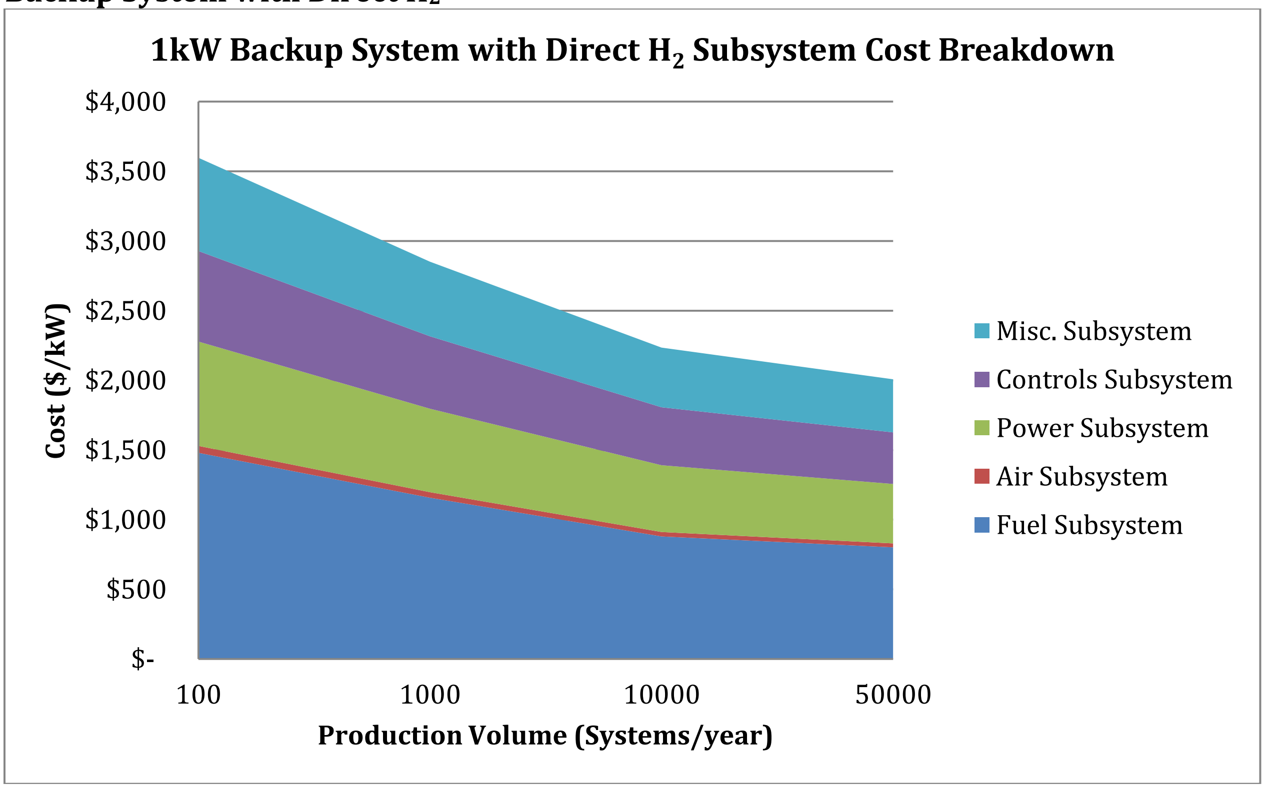


(e) Subsystem cost breakdown of CHP system with reformate fuel (250 kWe system)
Figure D.2. Subsystem cost breakdown of CHP system with reformate fuel for: (a) 1 kWe system; (b)10 kWe system; (c) 50 kWe system; (d) 100 kWe system; (e) 250 kWe system

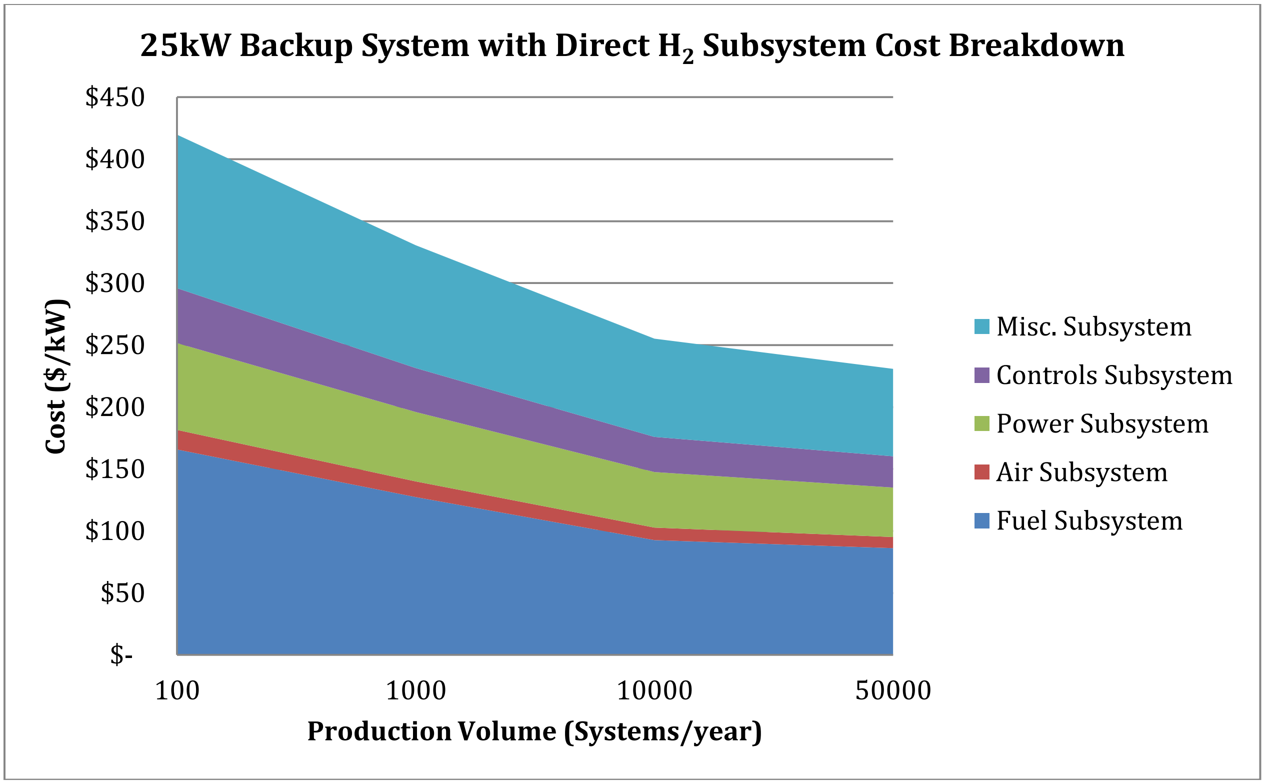
Subsystem/System Size	250kW	100kW	50kW	10kW	1kW
Fuel Processing	28%	27%	23%	32%	34%
Air	6%	7%	7%	11%	13%
Coolant	11%	14%	7%	13%	8%
Power	38%	30%	37%	23%	25%
Controls	12%	15%	18%	10%	9%
Miscellaneous	5%	7%	9%	12%	10%

Table D.1. Subsystem percentage cost breakdown for CHP system with reformate fuel (for 1000 systems/year)

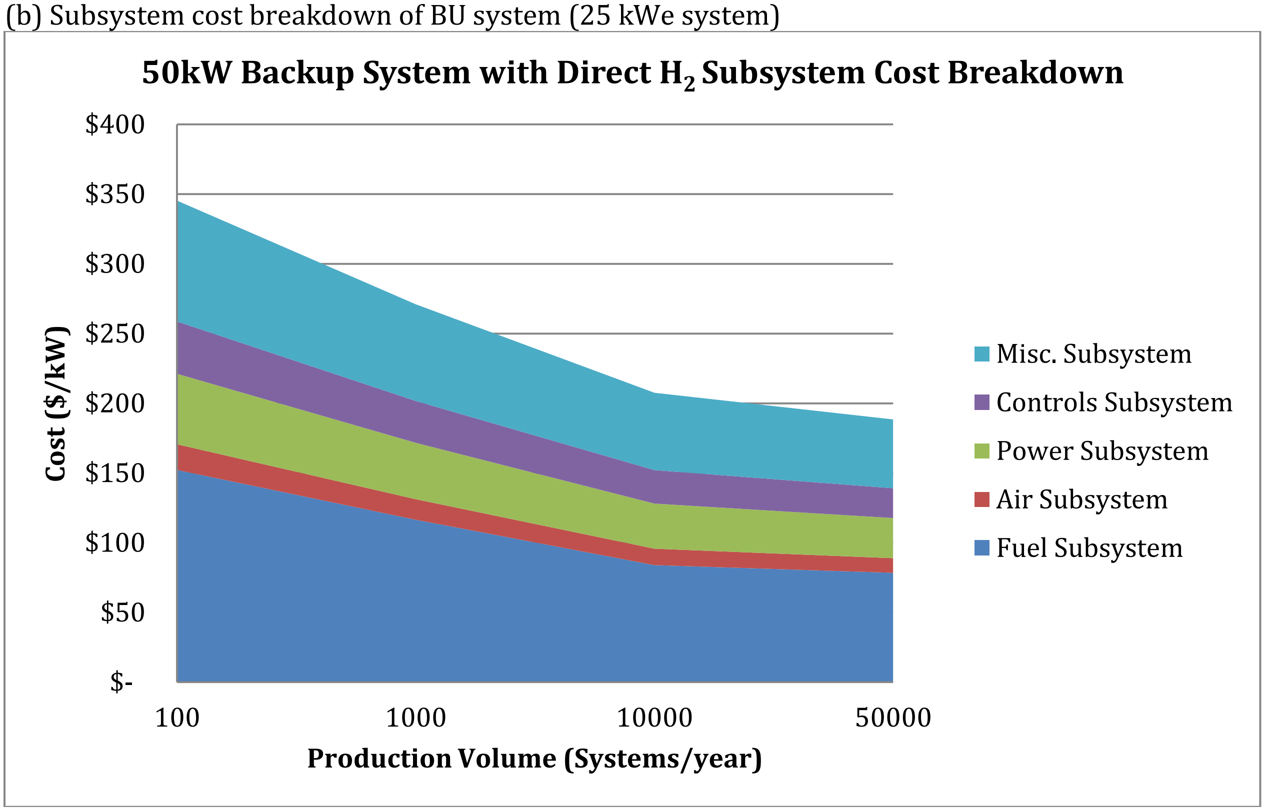
Backup System with Direct H_2



(a) Subsystem cost breakdown of BU system (1 kWe system)

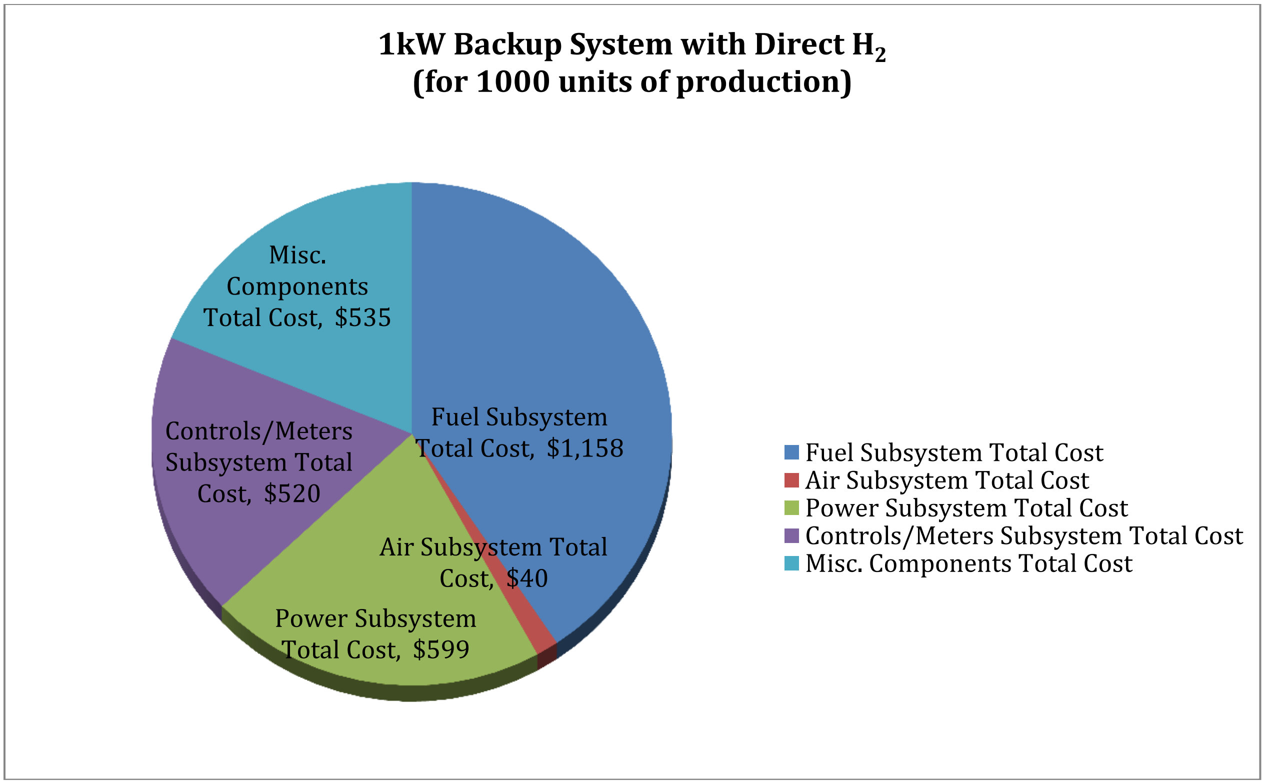


(b) Subsystem cost breakdown of BU system (25 kWe system)

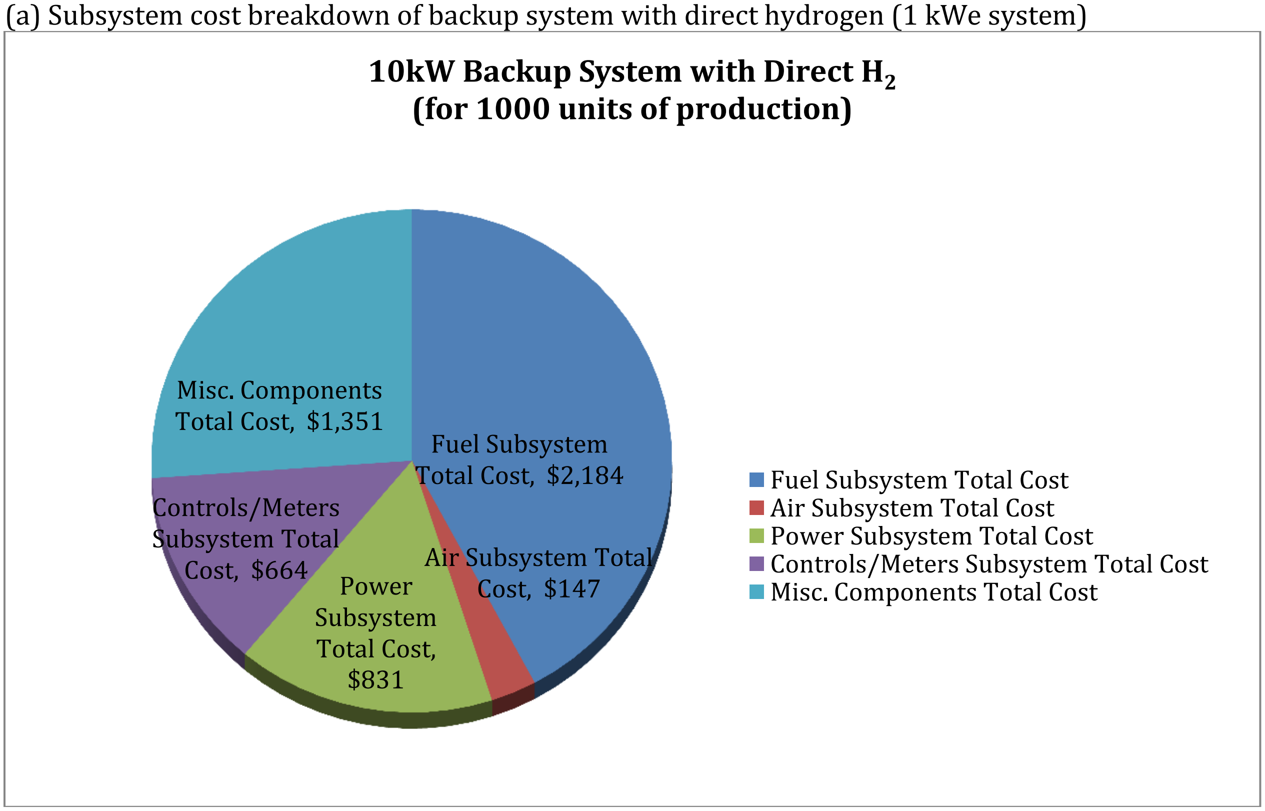


(c) Subsystem cost breakdown of BU system (50 kWe system)

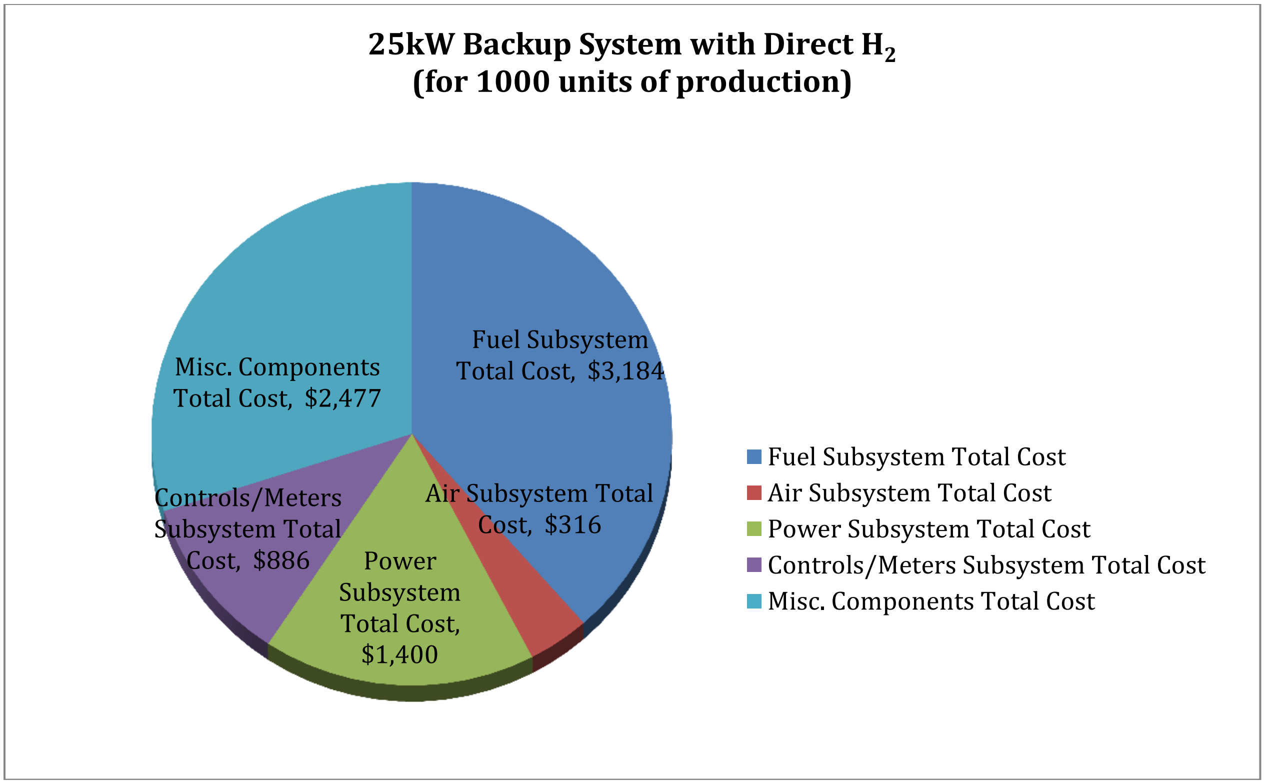
Figure D.3 Subsystem cost breakdown of backup direct H_2 system for: (a) 1 kWe system; (b) 25 kWe system; (c) 50 kWe system



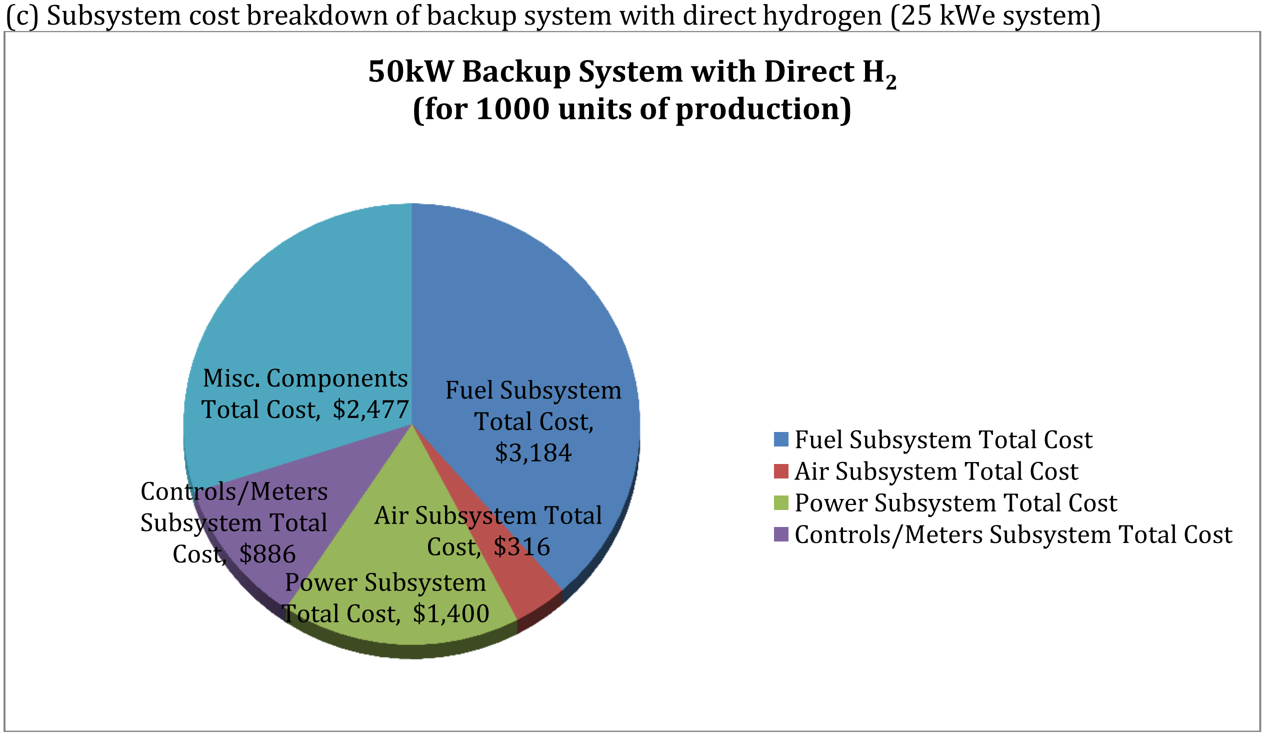
(a) Subsystem cost breakdown of backup system with direct hydrogen (1 kWe system)



(b) Subsystem cost breakdown of backup system with direct hydrogen (10 kWe system)



(c) Subsystem cost breakdown of backup system with direct hydrogen (25 kWe system)

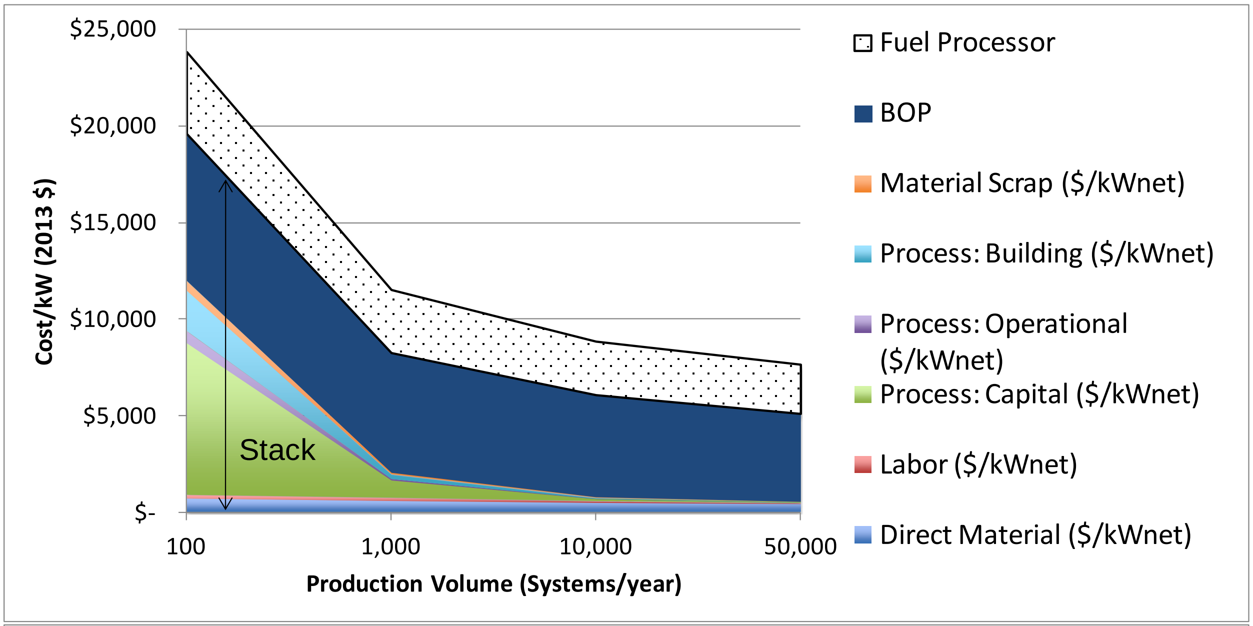


(d) Subsystem cost breakdown of backup system with direct hydrogen (50 kWe system)

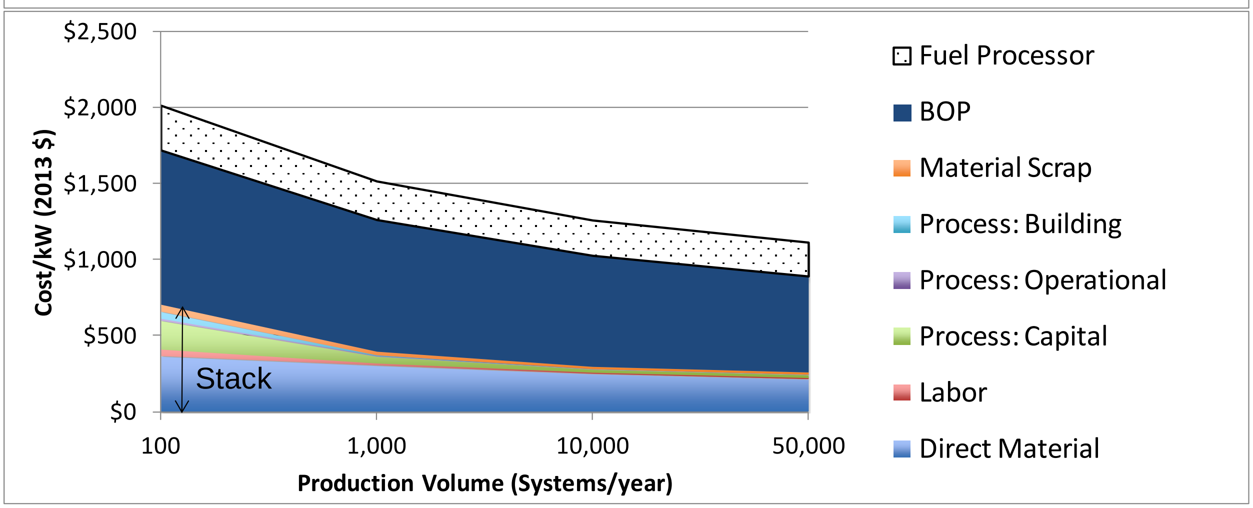
Figure D.4. Subsystem cost breakdown of backup direct H_2 system for: (a) 1 kWe system; (b) 10 kWe system; (c) 25 kWe system; (d) 50 kWe system

Appendix E: Direct Costing Results for CHP and Backup Power Systems

(a) 1 kWe



(b) 50kWe



(c)250 kWe

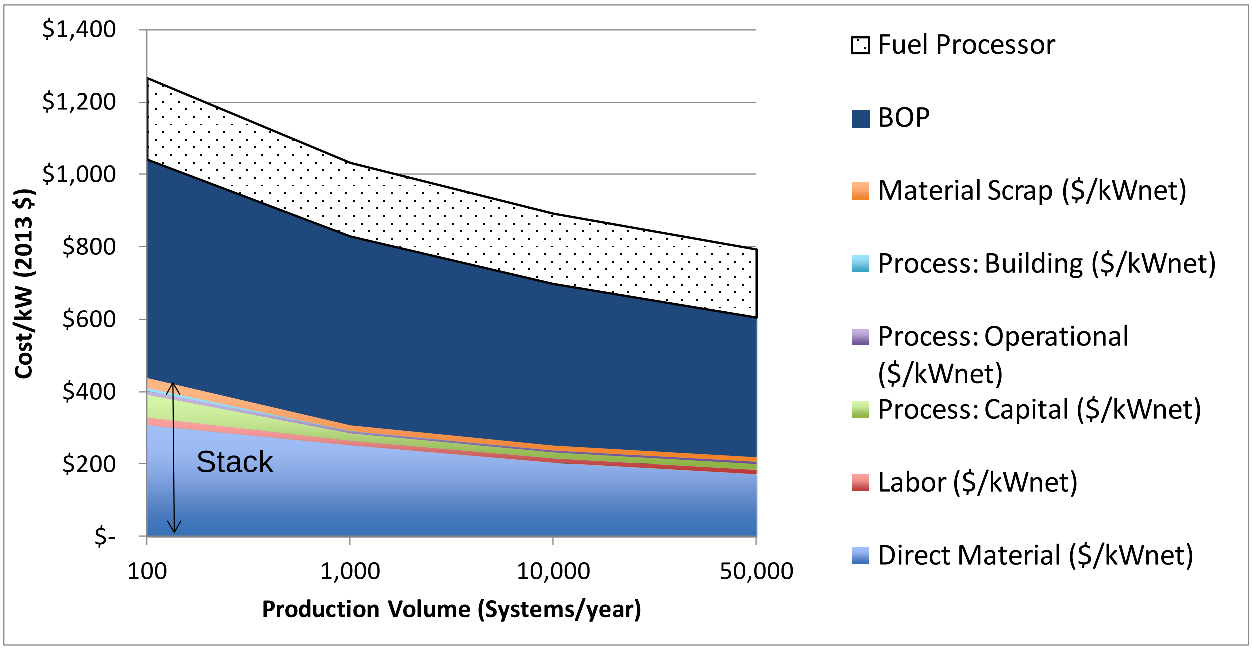


Figure E.1. Direct costs for 1, 50, 250kWe CHP systems with reformate fuel.

System Size (kW)	1			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Fuel Cell Stack Direct Material ($/kWe$_{net}$)	707.95	583.73	487.02	429.82
Fuel Cell Stack Labor ($/kWe$_{net}$)	169.77	148.32	70.65	25.22
Fuel Cell Stack Process: Capital ($/kWe$_{net}$)	7,896.43	931.97	137.49	45.56
Fuel Cell Stack Process: Operational ($/kWe$_{net}$)	609.81	77.61	17.56	8.49
Fuel Cell Stack Process: Building ($/kWe$_{net}$)	2,098.06	217.07	27.27	6.07
Fuel Cell Stack Material Scrap ($/kWe$_{net}$)	491.44	82.38	38.99	24.89
Fuel Cell Stack Cost	**11,973**	**2,041**	**779**	**540**
BOP_Non-Fuel Processor	**7,632**	**6,226**	**5,309**	**4,578**
BOP_Fuel Processor	4,239	3,263	2,770	2,547
Total ($/kWe$_{net}$)	23,844	11,530	8,858	7,665

(a)

System Size (kW)	50			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Fuel Cell Stack Direct Material ($/kWe$_{net}$)	362.22	300.59	244.97	210.08
Fuel Cell Stack Labor ($/kWe$_{net}$)	46.18	16.80	12.38	12.11
Fuel Cell Stack Process: Capital ($/kWe$_{net}$)	186.33	42.58	18.33	17.58
Fuel Cell Stack Process: Operational ($/kWe$_{net}$)	19.40	7.42	4.90	5.13
Fuel Cell Stack Process: Building ($/kWe$_{net}$)	43.54	4.72	0.96	0.74
Fuel Cell Stack Material Scrap ($/kWe$_{net}$)	46.89	24.14	15.26	14.26
Fuel Cell Stack Cost	705	396	297	260
BOP_Non-Fuel Processor	1,013	865	730	631
BOP_Fuel Processor	293	253	232	222
Total ($/kWe$_{net}$)	2,011	1,514	1,258	1,113

(b)

System Size (kW)	250			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Fuel Cell Stack Direct Material ($/kWe$_{net}$)	307.11	251.45	203.33	171.57
Fuel Cell Stack Labor ($/kWe$_{net}$)	20.94	12.28	11.69	11.56
Fuel Cell Stack Process: Capital ($/kWe$_{net}$)	63.80	21.10	17.04	16.83
Fuel Cell Stack Process: Operational ($/kWe$_{net}$)	9.13	5.07	4.96	6.09
Fuel Cell Stack Process: Building ($/kWe$_{net}$)	8.59	1.36	0.69	0.66

Fuel Cell Stack Material Scrap ($/kWe$_{net}$)	28.33	16.22	13.85	12.85
Fuel Cell Stack Cost	438	307	252	220
BOP_Non-Fuel Processor	602	521	446	385
BOP_Fuel Processor	225	203	194	188
Total ($/kWe$_{net}$)	1,265	1,031	891	792

(c)

Table E.1. Direct cost tables for 1, 50, 250kWe CHP systems with reformate fuel.

(a)
1kWe

(b)
25kWe

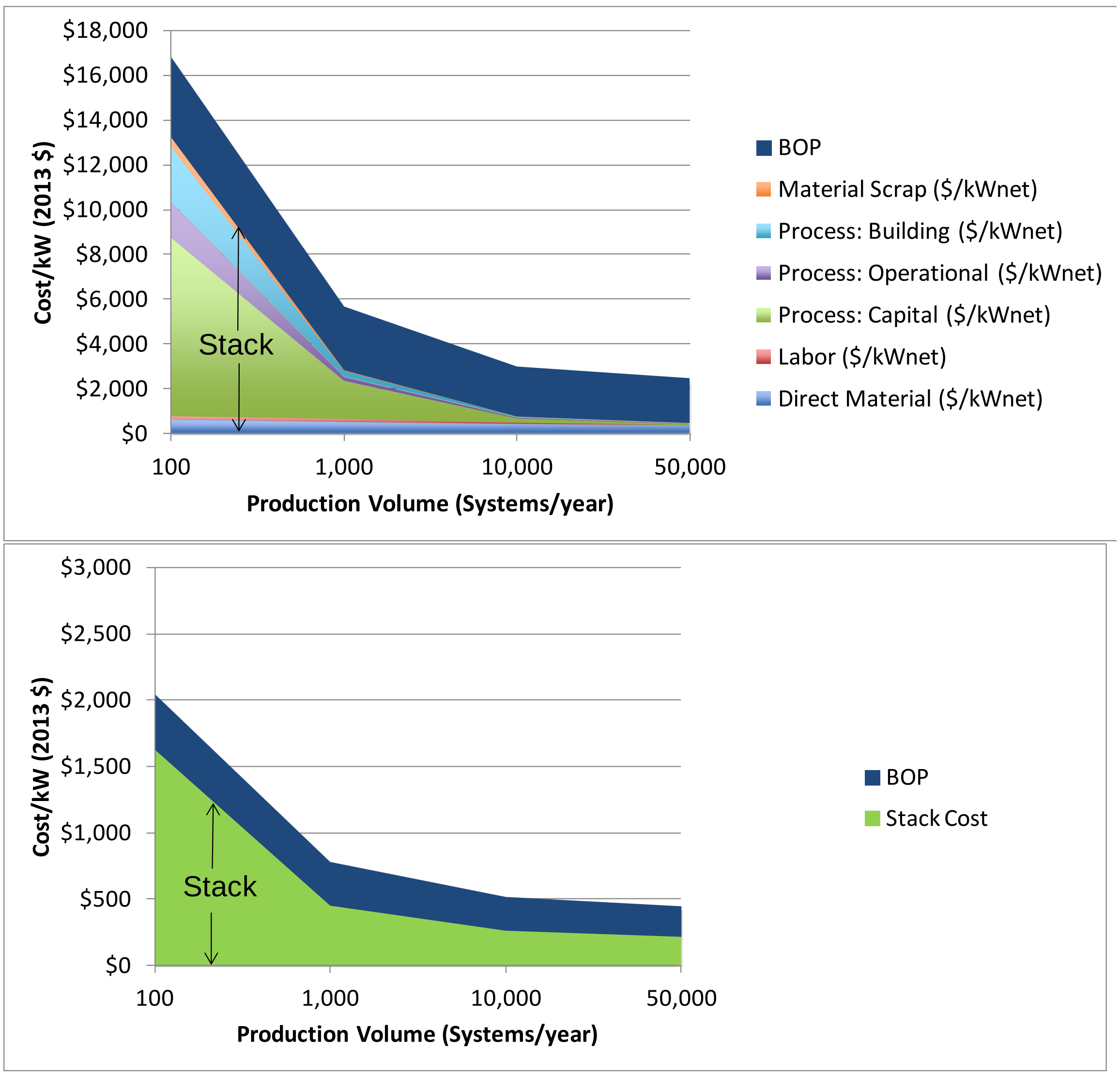


Figure E.2. Direct costs for 1, 25kWe backup power systems with direct H_2 fuel.

System Size (kW)	1			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Fuel Cell Stack Direct Material ($/kWe$_{net}$)	627.20	505.79	411.26	357.76
Fuel Cell Stack Labor ($/kWe$_{net}$)	154.26	153.74	84.94	24.70
Fuel Cell Stack Process: Capital ($/kWe$_{net}$)	7,964.44	1,697.15	181.55	43.17
Fuel Cell Stack Process: Operational ($/kWe$_{net}$)	1,557.30	165.85	27.85	12.85
Fuel Cell Stack Process: Building ($/kWe$_{net}$)	2,474.01	251.30	28.82	6.07
Fuel Cell Stack Material Scrap ($/kWe$_{net}$)	452.73	47.27	17.17	13.34
Fuel Cell Stack Cost ($/kWe)	13,230	2,821	752	458
BOP ($/kWe)	3,597	2,852	2,235	2,008
Total ($/kWe)	16,827	5,673	2,987	2,466

(a)

System Size (kW)	25			
Production Volume (Systems/yr)	100	1,000	10,000	50,000
Stack Cost ($/kWe)	1,630	449	260	214
BOP ($/kWe)	420	331	255	231
Total ($/kWe)	2,050	780	515	445

(b)

Table E.2. Direct cost tables for 1, 25kWe backup power systems with H_2 fuel.

Appendix F: Life Cycle Assessment (LCA) Model

F.1. Classical LCA and Use-Phase Modeling

Scope of LCA Study

We developed a life cycle assessment (LCA) model to characterized the impacts and/or benefits of combined heat and power fuel cell systems for commercial applications. The objective of this model was to provide estimates for cost and environmental impacts associated with using such kind of power system and possible energy and GHG emission savings upon replacing current power systems with a fuel cell power system.

A typical LCA model includes all economic and environmental inputs and outputs that are part of the product's life cycle. However, the majority of LCA studies focus on one or more specific life-cycle components, as it is hard to track all parameters and factors in the entire life cycle. Therefore it is necessary to define the scope of the study and system boundaries and then indicate which processes and/or material flows are not included in the LCA. In the present model we have split life cycle into five distinct phases including pre-manufacturing, manufacturing phase, the use-phase and the End-of-Life (EOL) phase; and another indirect phase was also added to the model to account for fuel extraction, processing and transportation. Table F.1 below shows the detailed scope of this LCA model.

Inventory analysis was performed for all fuel cell components (stack and balance of plant), which includes information about all materials used to make these parts, manufacturing routes, and possible end-of-life of these parts as well as energy and GHG emission associated with each of these phases. Argonne National lab has developed a detailed model for environmental impacts of fuel extraction and processing (GREET) which gives a detailed assessment of all steps of hydrogen production and processing (GREET 2012) and their model was adopted for fuel production.

Life cycle phase	Scope	Method
Pre-manufacturing Phase	Material types and their embodied energies Extraction/processing methods Type of fuel used to produce these materials (coal, electricity, etc.) Estimated amount of emissions produced per kg of material	Cambridge Engineering Selector (CES 2008) software was used to estimate most of the pre-manufacturing estimates, also we used other sources to estimate pre-manufacturing energy and GHG emissions for non-traditional materials like PFSA
Manufacturing Phase	The materials used for components and parts The processes (e.g., cold transforming of steel, molding of plastic, coating of CCM, injection molding of BPP, etc.) used for the product manufacturing Energy expenditures to manufacture different components The emissions caused and waste generated by product manufacturing	Major manufacturing processes (or route of manufacturing processes if we have more than one required to make individual parts) were analyzed to assess energy and GHG emission associated with making all parts of the fuel cell (stack and balance of plant).

Use and Maintenance Phase	Energy associated with use-phase (generated and purchased energies) Emissions during useful lifetime. The installation materials and processes for installing the fuel cell system at the client's site Components and parts that need to be replaced during the fuel cell system lifetime Installation of fuel cell system in site, maintenance of components, and replacement components (Lipman et al. 2004).	We developed use-phase model using Analytica software. This model is structured around energy demand for several buildings in different climate zones in the U.S. The goal is to provide accurate analysis for this phase rather than assuming some numbers for this phase as it account for most of LCA energy and GHG emissions.
End-of-Life Phase	Considered end-of-life scenarios for all materials. Some parts can be recycled (e.g. Pt in the CCM); while other parts can be reconditioned and reused (e.g. plates)	End-of-life assumptions were obtained from different sources, including CES2008 and other scientific databases.
Fuel (Resources and Production)	This phase accounts for cost, energy and emissions associated with fuel extraction, refining and transportation	GREET model was used to estimate energy expenditures and GHG emissions associated with NG extraction and H_2 reforming process.

Table F.1. Scope of the life cycle assessment (LCA) model

Inventory Analysis

The inventory analysis was performed for all stack components and balance of plant parts (Figure F.1). Balance of plant (BOP) parts are generally outsourced from different vendors and BOP part lists were developed with a bottom-up analysis approach described in the BOP chapter of the main report (Chapter 5). Inventory tables include type of materials used to make these parts; weight estimates of these parts, manufacturing processes used to make these products and associated energy with each manufacturing process. Most of the inventory data were obtained from CES2008 for traditional manufacturing process, while other nontraditional manufacturing processes like CCM coating or GDL manufacturing were modeled using DFMA analysis. DFMA models contain detailed information about energy expenditure per manufacturing module and type of energy used to make each component. Examples of inventory analysis for a hydrogen tank and hydrogen pump motor (Figure F.2) showing materials, weight estimates and manufacturing processes required to produce these parts are shown in these tables. These tables also show calculations of pre-manufacturing, manufacturing and end-of-life energy and GHG emissions.

Although the majority of fuel cell life cycle assessment (LCA) disregards pre-manufacturing and manufacturing phases for simplicity, we include them here for a more comprehensive LCA study.

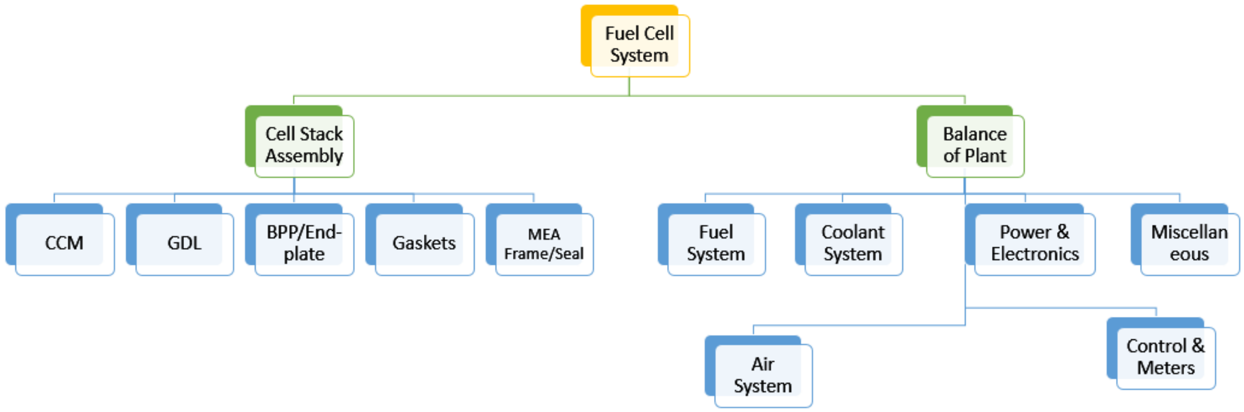


Fig. F.1. Major components of the fuel cell (stack and balance of plant).

Subassembly/Part Name: Fuel/Hydrogen tank					
Materials	**Estimated wt. (kg)**				
	1 kW system	10 kW system	50 kW system	100 kW system	250 kW system
Aluminum 5086-0 Tank	15.00	15.00	59.55	98.18	172.73
	Embodied energy (kJ/sys)				
	3.11E+06	3.11E+06	1.24E+07	2.04E+07	3.58E+07
	Pre-Mfg CO2 (kg/sys)				
	180.00	180.00	714.55	1178.18	2072.73
Manufacturing processes	**Estimated Mf'g Energy (kJ/part)**				
	1 kW system	10 kW system	50 kW system	100 kW system	250 kW system
Rolling	4.01E+04	4.01E+04	1.59E+05	2.62E+05	4.61E+05
Blanking/Stamping	3.68E+02	3.68E+02	1.46E+03	2.41E+03	4.23E+03
Welding	8.03E+02	8.03E+02	3.19E+03	5.25E+03	9.24E+03
Total	**4.12E+04**	**4.12E+04**	**1.64E+05**	**2.70E+05**	**4.75E+05**
	Estimated Mf'g CO2 (kg/part)				
Rolling	3.20	3.20	12.71	20.96	36.88
Blanking/Stamping	1.08	1.08	4.27	7.04	12.39
Welding	0.53	0.53	2.10	3.47	6.10
Total	**4.81**	**4.81**	**19.09**	**31.47**	**55.37**
	Estimated EOL Energy & CO2				
Energy (kJ/part)	-2.85E+06	-2.85E+06	-1.13E+07	-1.86E+07	-3.28E+07
CO2 (kg/part)	-164.55	-164.55	-653.23	-1077.07	-1894.85

(a)

Subassembly/Part Name: Air pump motor					
Materials	**Estimated wt. (kg)**				
	1 kW system	**10 kW system**	**50 kW system**	**100 kW system**	**250 kW system**
Cast iron	8.41	11.14	14.77	19.77	58.18
Stainless Steel	2.52	3.34	4.43	5.93	17.45
Alumnium	3.36	4.45	5.91	7.91	23.27
Copper	2.52	3.34	4.43	5.93	17.45
	Embodied energy (KJ/sys)				
	1.23E+06	1.63E+06	2.16E+06	2.89E+06	8.49E+06
	Pre-Mfg CO2 (kg/sys)				
	73.06	96.76	128.35	171.80	505.51
Manufacturing processes	**Estimated Mf'g Energy (kJ/part)**				
	1 kW system	**10 kW system**	**50 kW system**	**100 kW system**	**250 kW system**
Casting	3.96E+04	5.24E+04	6.96E+04	9.31E+04	2.74E+05
Cold forming (steel)	1.44E+04	1.90E+04	2.52E+04	3.38E+04	9.94E+04
Cold forming (copper)	7.09E+03	9.39E+03	1.25E+04	1.67E+04	4.90E+04
Machining (Stainless steel)	5.69E+02	7.53E+02	9.99E+02	1.34E+03	3.94E+03
Welding (SS and cast iron)	1.14E+03	1.51E+03	2.00E+03	2.68E+03	7.89E+03
Total	**5.40E+04**	**7.15E+04**	**9.48E+04**	**1.27E+05**	**3.73E+05**
	Estimated Mf'g CO2 (kg/part)				
Casting	2.38	3.15	4.17	5.59	16.44
Forging/rolling	1.15	1.52	2.02	2.70	7.94
Cold forming (copper)	0.43	0.57	0.76	1.01	2.98
Machining (Stainless steel)	0.15	0.20	0.27	0.36	1.05
Welding (steel and cast iron)	1.07	1.42	1.88	2.51	7.40
Total	**5.18**	**6.85**	**9.09**	**12.17**	**35.81**
	Estimated EOL Energy & CO2				
Energy (kJ/part)	-1.04E+06	-1.37E+06	-1.82E+06	-2.44E+06	-7.17E+06
CO2 (kg/part)	-61.51	-81.46	-108.05	-144.63	-425.57

(b)

Figure F.2. Examples of inventory analysis for: (a) hydrogen tank; and (b) air pump motor.

It is important to highlight the potential for recycling/reusing parts or components at the end-of-life where some materials/parts can be recycled or re-conditioned for another secondary application. Table F.2 shows recycle fraction of some materials used in making fuel cells and possible end-of-life route compiled from several sources (CES 2008, Rooijen, 2006, EPA 2014b). In this study we assumed that recycling will save some energy expenditures and GHG emissions associated with the extraction of virgin materials, and hence end-of life phase values appear as negative numbers in the inventory analysis wherever recycling can be made to any part/material. It t is important to note, however, that energy and emissions related to the disassembly of the fuel cell system into the materials, which are sent to waste treatment, are not taken into account as we believe they are insignificant compared to other LCA impacts.

Material	Recycled fraction	End-of-life scenario
Steel	90%	Recycling
Stainless Steel	90%	Recycling
Cast Iron	90%	Recycling
Aluminum	95%	Recycling
Copper	90%	Recycling
Platinum	90%	Recycling
PVC	0%	Landfilling
Rubber	0%	Landfilling
Carbon	80%	Recycling

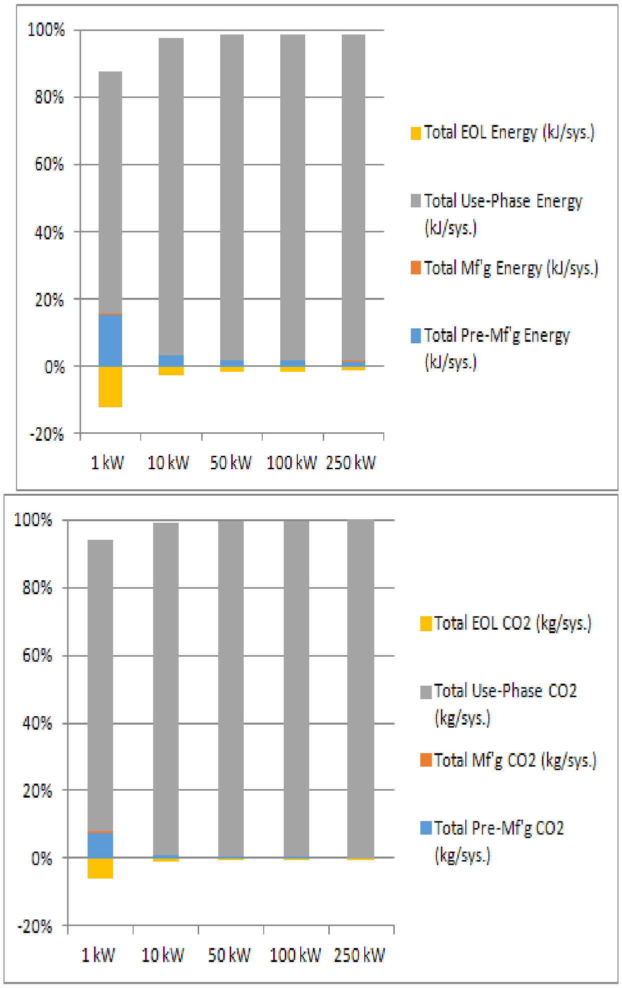
Table F.2. Recycled fraction for some materials used in fuel cell systems

Table F.3 below summarizes energy and CO_2 emissions associated with these three LCA phases (pre-manufacturing phase, manufacturing phase and end-of-life phase). The other two LCA phases (use and maintenance phase and fuel production) are discussed in the next section. This table shows that pre-manufacturing phase has greater environmental impacts over the other two cases (in fact, the use-phase accounts for the dominant portion of environmental impacts). Also, there is the potential for material, energy and CO_2 emission savings by recycling end-of-life components (See Figure F.3).

LCA Phase	**Fuel Cell Capacity**				
	1 kW	10 kW	50 kW	100 kW	250 kW
Total Pre-Mf'g Energy (kJ/sys.)	3.41E+07	5.79E+07	1.59E+08	2.81E+08	6.00E+08
Total Pre-Mf'g CO_2 (kg/sys.)	2.04E+03	2.52E+03	4.48E+03	6.79E+03	1.10E+04
Total Mf'g Energy (kJ/sys.)	1.43E+06	1.66E+06	2.45E+06	3.36E+06	4.70E+06
Total Mf'g CO_2 (kg/sys.)	9.81E+01	1.16E+02	1.78E+02	2.49E+02	3.58E+02
Total EOL Energy (kJ/sys.)	-2.76E+07	-4.54E+07	-1.35E+08	-2.43E+08	-5.30E+08
Total EOL CO_2 (kg/sys.)*	-1.63E+03	-2.02E+03	-3.70E+03	-5.66E+03	-9.38E+03

Negative numbers appear on EOL results represent possible savings in energy and CO_2 emissions upon recycling of EOL parts

Table F.3. Energy and CO_2 emissions associated with other LCA phases



(a) Life Cycle Energy Analysis (b) Life Cycle CO_2 Analysis

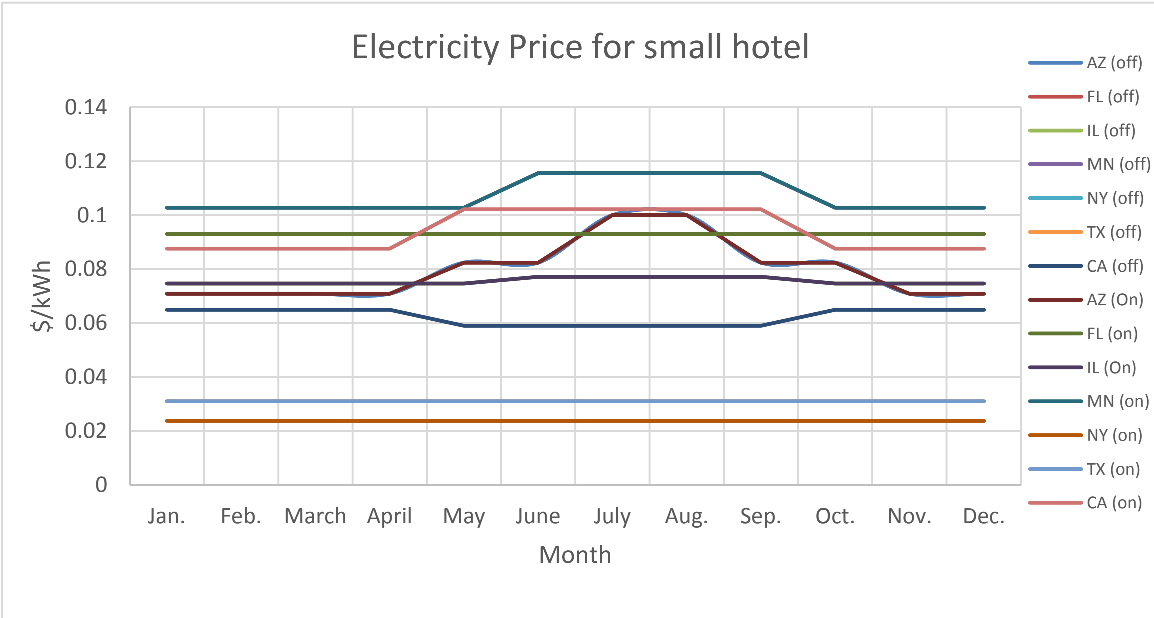
Figure F.3. Life cycle energy and CO_2 assessment for different fuel cell sizes (Note: in this chart use-phase analysis includes fuel processing onsite)

Operation and Maintenance Cost Calculations

CHP Application - PEM	Near-Term	Future	Unit
System life	15	20	years
Stack life	20,000	40,000	hours
Reformer life (if app.)	5	10	years
Compressor/blower life	7.5	10	years
WTM sub-system life	7.5	10	years
Battery/startup system life	7.5	10	years

Table F.4. Estimated lifetime for some major components in the fuel cell system based on functional specifications

Figure F.4 below shows electricity tariffs and natural gas prices for several cities in the United States.



(a)

State	$/kWh	$/therm
Arizona	0.0357	1.045
Minnesota	0.0258	0.755
Illinois	0.0292	0.857
New York	0.0331	0.971
Houston	0.0263	0.771
California	0.0277	0.812

(b)

Figure F.4. Different price components for small hotels in six different U.S. cities: (a) electricity tariff structure. (On) and (off) refer to on- and off-peak electricity; and (b) average price of commercial natural gas for six states (EIA 2008-2013[21]).

Estimation of Replacement Cost

The example below summarizes the calculation method to estimate operational and maintenance (O&M) costs for a 50 kW FC system. Starting with initial cost for some major subsystems and their replacement frequencies, we converted all future values to present values (NPV) using a 5% discount rate, then we converted these NPVs into equal annual payments as shown below.

[21] http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm, Accessed October 2, 2014

Part	Replacement Frequency (Year)	Capital Cost ($)*	Net Present Value (NPV)‡‡	Annual Payment ($)
Stack†	20,000 hr	19,815	$40,668.86	$4,465.22
Reformer	5	12,651	$17,325.43	$1,902.24
Compressor/blower	10	3,823	$2,300.05	$252.53
WTM sub-system	10	3,655	$2,198.98	$241.44
Battery/startup system	5	510	$698.44	$76.68
Total			$63,191.75	$6,938.11

* Cost based on this study's DFMA and system cost analysis for 50kW systems.
*** All future values were converted to present values (2013$) using 5% discount rate
† The fuel cell stack is assumed to be refurbished every 20,000 hours by conditioning some components like plates and re-using them in the stack (refurbishment cost assumed to be 50% of the original cost), and the is assumed to be completely replaced every 40,000 hours.
‡ Assumed 96% availability of the system for scheduled stack replacement.
‡‡ End-of-life parts assumed to be sold at 2% of original value.

Table F.5. Replacement schedule with associated cost

Now for a full duty cycle, the maximum FC power generation is 24hr/day x 365days/yr x 50 kW x 0.96 (availability) = 420,480 kWh per year

Displaced Electricity by FC for small hotel in AZ=382,253 kWh
Displaced Electricity by FC for small hotel in IL=345,791 kWh

If we estimate average displaced power by fuel cell to be 350,000 kWh, this gives the following O&M cost due to equipment replacement: 6,938/350k= $0.02 per kWh.

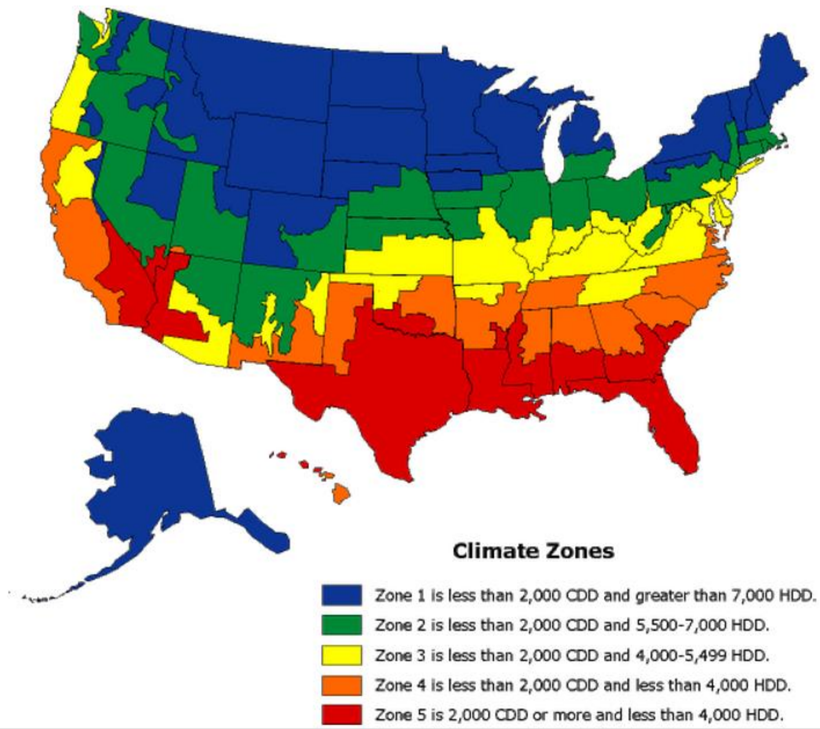
Although this simple calculation method gives a reasonable estimate of O&M cost for equipment replacement, other assumptions may be possible such as reusing components after making some conditioning/refurbishment or more frequent stack replacement which may lower or increase the O&M cost. In the model implementation a range of O&M costs from $0.02-0.06 per kWh are available, so that the user can select an O&M cost that is suitable for the particular fuel cell system and set of assumptions.

Example of load shapes for small hotel in Phoenix, AZ

Several commercial buildings were selected from different climate zones in the US (see Fig. F.5 for these climate zones). The selection of these buildings was made to analyze the effect of installing fuel cell systems on the overall cost of ownership including GHG emissions and other externalities. The building types included include: small hotels, hospitals, and small office buildings.

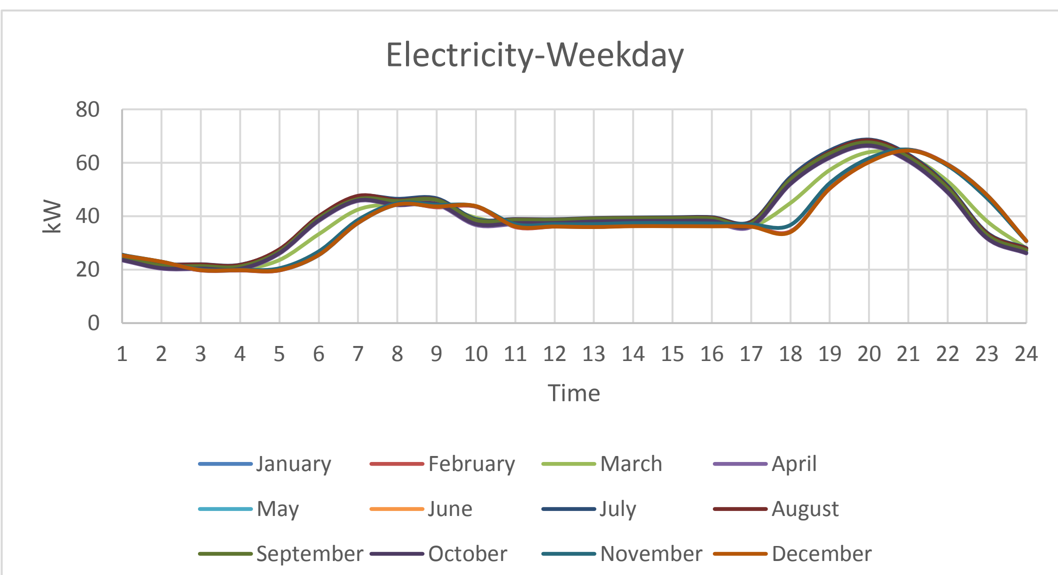
This study included buildings from New York City, Chicago, Minneapolis, Houston, Phoenix, and San Diego. For example, Phoenix and Minneapolis represent two very different climate zones in the U.S., a semi-arid zone and humid-continental zone, respectively.

Examples of heating and electrical load shapes are shown in Fig. F.6 for small hotel in Phoenix, AZ.

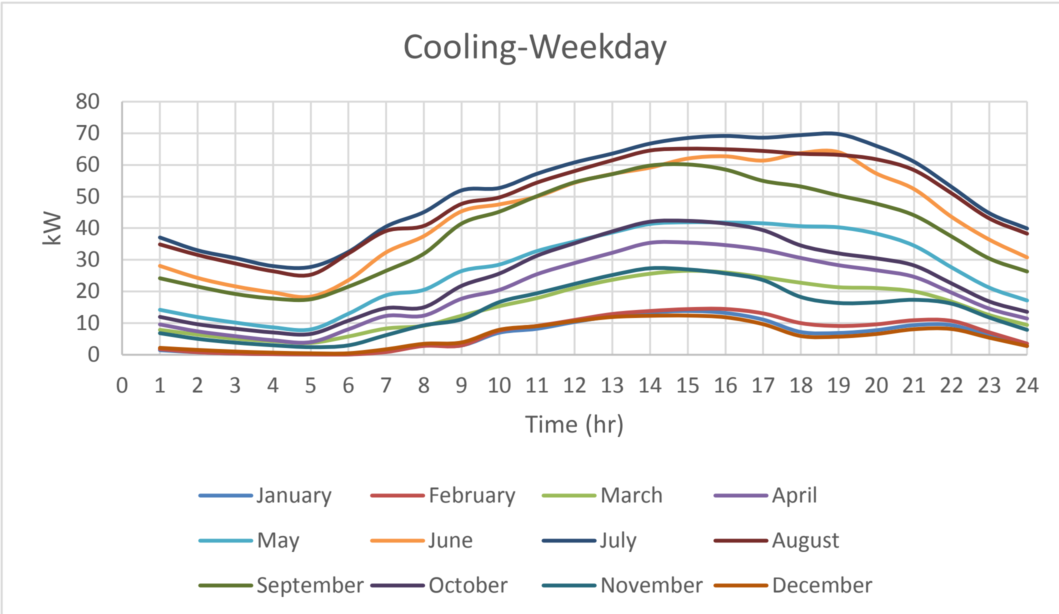


[Source: http://www.eia.gov/emeu/recs/climate_zone.html]

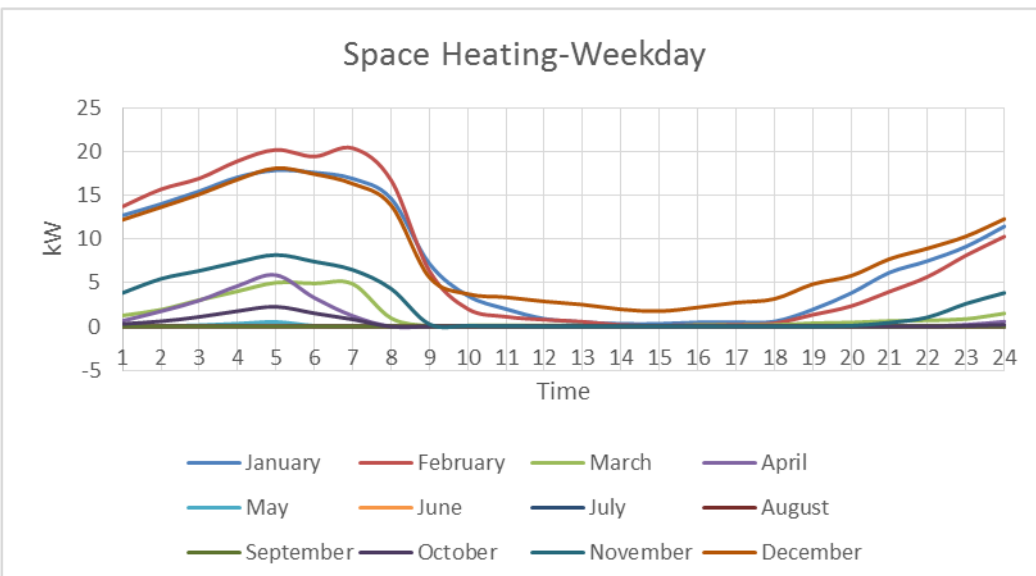
Figure F.5. Climate zones in USA



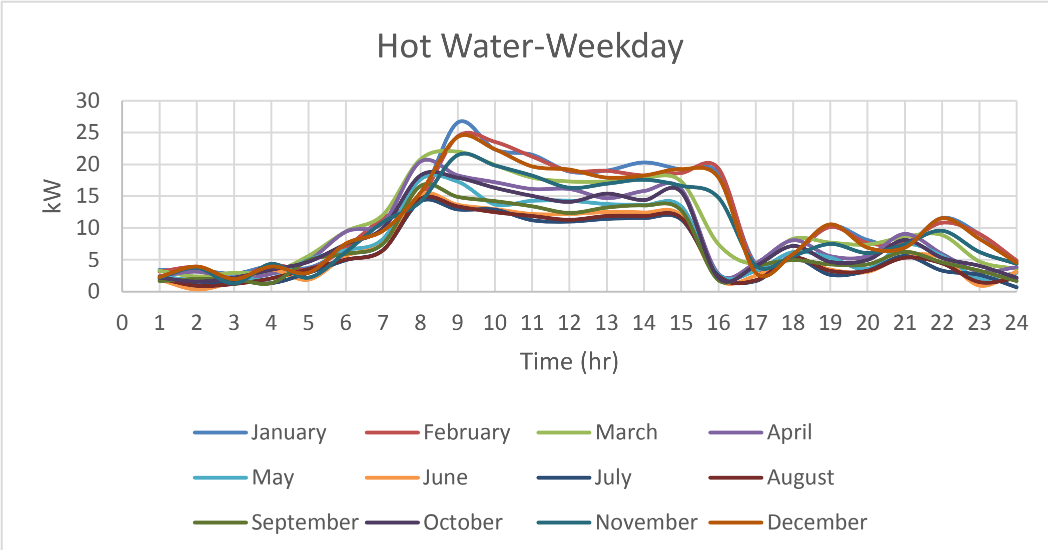
(a) Non-cooling electricity load profile for a small hotel in Phoenix, AZ (Weekday)



(b) Electricity for cooling load profile for a small hotel in Phoenix, AZ (Weekday)



(c) Space heating load profile for a small hotel in Phoenix, AZ (Weekday)



(d) Hot water heating load profile for a small hotel in Phoenix, AZ (Weekday)

Figure F.6. Load profiles for (a) non-cooling electricity, (b) electricity for cooling, (c) space; and (d) water heating, respectively for small hotel in Phoenix, AZ.

Fuel cell net electrical efficiency as a function of power load was assumed to follow the efficiency curve shown in Fig. F.7, which was made based on FC data from the literature and validated by our industrial partners. This representative system efficiency curve provides more accurate analysis in terms of FCS fuel requirements and waste heat availability.

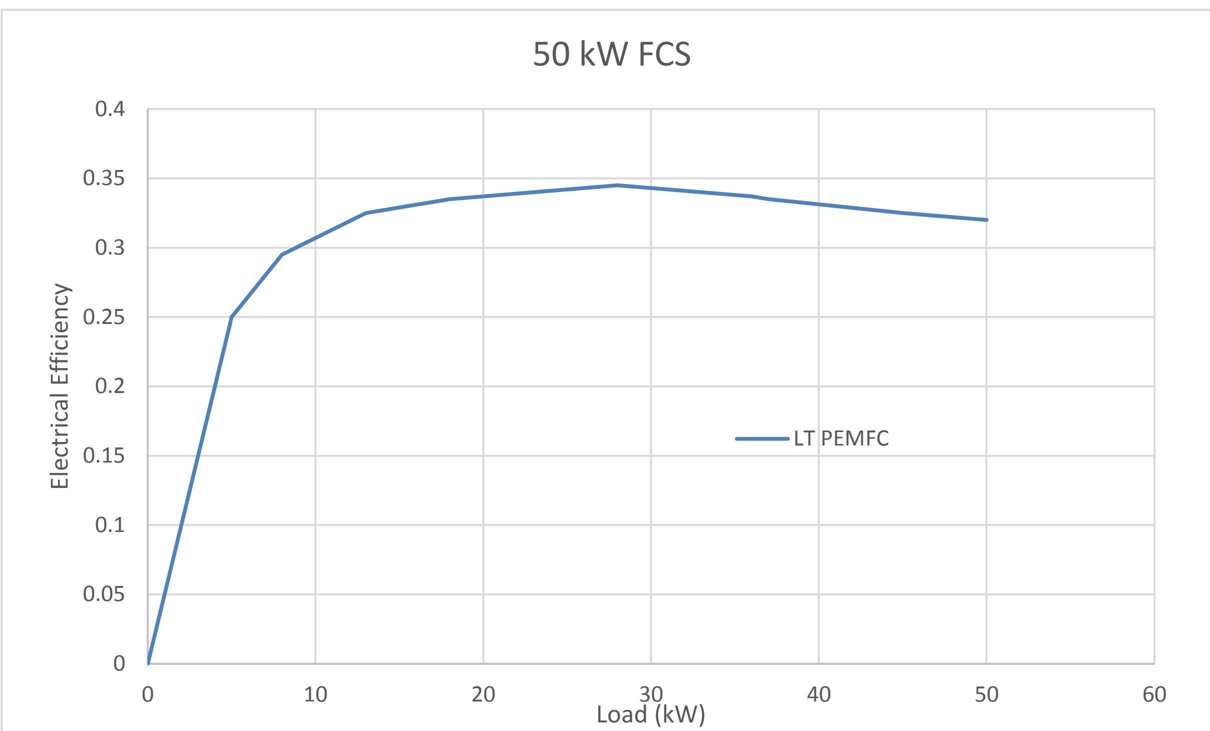


Figure F.7. Net electrical efficiency curve for 50 kW reformate FC (Total FC system efficiency of 83% is assumed which is made from the sum of electrical efficiency and thermal efficiency).

For the hospital case, either one 250kW FC system or four 250kW FC systems assumed to be built. The latter is taken rather than a single 1000 kW system since a 250kW system was modeled in Chapter 6 and large scale installation may in fact comprise several smaller systems. Table F.6 shows model assumptions for hospitals. In the use-phase model for hospitals, a new FC system is triggered if the first one is not enough to supply required load (load here is the sum total of electricity and cooling loads) and so on for the third and fourth FC system.

However, all triggered system are constrained to run at 50% or more of their rated power capacity in order to have them operating at high efficiency. Note the power efficiency for each individual fuel cell will fall below 30% if it is operating at <20% of its rated power. If all four systems combined together cannot supply the required load at any given time, then this unmet demand will be purchased from the grid. Similar logic is also used for total heating demand and supply; i.e. if the FC system cannot provide all of the heat demand, the system will cover these heating loads using natural gas-fired boiler systems.

For hospitals, as shown in Table F.6, overall in-used heat recovery efficiency of a unit installed is fairly low–assuming that waste heat grade is suitable for water heating only, at 1-2% for 1000kW and 4-7% for 250kW. These fairly low in-use heat utilizations indicate that there is even greater opportunity for cost savings with fuel cells when configurations are identified with higher heat utilizations.

Parameter	Phoenix, AZ	Minneapolis, MN	Chicago, IL	NYC, NY	Houston, TX	San Diego, CA	Unit
Building Type	**Hospital**						
FC System Size	**250kW or 1MW (4x250kW systems)**						kW
FC Power Utilization (250kW)	100%	100%	100%	100%	100%	93%	%
FC Power Utilization (4x 250kW)	96.5%	79.7%	85%	83.1%	98.1%	24.7%	%
FC Heat Utilization space and water heating; water heating only (250kW)	84.9%; 4.2%	100%; 6.9%	100%; 6.5%	100%; 6.3%	88.9%; 4.5%	18.1%; 2.3%	%
FC Heat Utilization space and water heating; water heating only (4x 250kW)	21.2%; 1.1%	29.0%; 1.7%	27.6%; 1.6%	32.4%; 1.6%	22.2%; 1.1%	4.54%; 0.57%	%
Displaced Electricity by FC (250kW)	2102	2102	2102	2102	2102	1965	MWh/yr
Heat produced by FC (250kW)	3332	3332	3332	3332	3332	3308	MWh/yr
Displaced Electricity by FC (4x 250kW)	8112	6703	7117	6989	8251	2080	MWh/yr
Heat produced by FC (4x 250kW)	13282	11580	12114	12012	13305	4938	MWh/yr
Max. space heating displaced by FC	2689	3633	3467	4102	2812	529	MWh/yr

Max. water heating displaced by FC	140	230	215	210	151	76	MWh/yr
Capital costs of FC including installation cost	2200 (250kW) 2200 (4x 250kW)						$/kW
Electricity price	Variable by time	Variable by time	Variable by time	Variable by time	Variable by time	Variable by time	$/kWh
Demand Charge ($ /Peak kW per month)	4.05	8.98 (Oct.-May) 12.86 (Jun-Sep.)	5.86	17.95	12.39 (Oct.-May) 15.13 (Jun-Sep.)	19.96	$/kW
Natural Gas Cost	0.0357	0.0258	0.0292	0.0331	0.0263	0.0277	$/kWh
Scheduled maintenance cost ‡	3000	3000	3000	3000	3000	3000	$/yr
O&M cost	0.030	0.030	0.030	0.030	0.030	0.030	$/kWh
Days of FC operation per year	365	365	365	365	365	365	day
FC system availability‡‡	96%	96%	96%	96%	96%	96%	%
Lifetime of system	15	15	15	15	15	15	yr
Interest rate	5%	5%	5%	5%	5%	5%	%

‡ From CETEEM model (Lipman et al., 2004).
‡‡ In this analysis the CHP system was assumed to have a 96% availability factor and three outages during the year. One outage is assumed to be a planned maintenance outage and two are assumed to be unplanned forced outages.

Table F.6. Assumptions for cost and environmental impact model for the hospital case.

Installed equipment cost is estimated to be $2,200 for 250 kW fuel cell system based on this report's system costing at a volume of 100MW per year (Chapter 6).

Output of the use-phase model for hospitals is shown in Tables F.7 and F.8. Each table includes two cases: (1) total costs of FCS vs. No FCS where FCS supplies both hot water and space heating; and (2) total costs of FCS vs. No FCS where FCS supplies hot water only. Total costs for FCS are most competitive in the 250kW system size and seen be approaching the No FCS case cost in Minneapolis and San Diego (Table F.8).

Output results from use-phase model for hospital (1 MW FC system)												
	Phoenix, AZ		Minneapolis, MN		Chicago, IL		NYC, NY		Houston, TX		San Diego, CA	
Output	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell
FCS Power Utilization		96.50%		79.70%		85%		83.10%		98.11%		24.70%
FCS Heat Utilization WH+SH (WH only)		21.2% (1.1%)		29% (1.7%)		27.6% (1.62%)		32.4% (1.6%)		22.2% (1.1%)		4.5% (0.6%)
Total Electricity Demand (MWh/yr)	9,140		7,331		7,852		7,624		9,533		2,166	
Total Space Heating Demand (MWh/yr)	2,689		3,633		3,467		4,102		2,812		529	
Total Water Heating Demand (MWh/yr)	140		230		215		210		151		76	
Annual Generated Power by FC (MWh)		8,112		6,703		7,117		6,989		8,251		2,080
Annual Generated Heat by FC (MWh)		13,282		11,580		12,114		12,012		13,305		4,938
Capital Cost	0	264,941	0	264,941	0	264,941	0	264,941	0	264,941	0	264,941
O&M Cost	0	243,357	0	201,081	0	213,497	0	209,675	0	247,532	0	62,391
Scheduled Maintenance	0	3,000	0	3,000	0	3,000	0	3,000	0	3,000	0	3,000
Fuel Cost- FCS only	0	872,594	0	517,208	0	624,104	0	694,191	0	656,232	0	166,893
Residual Fuel Cost	100,839	0	99,542	1,915	107,626	398	142,926	3,659	77,908	0	16,759	0
Electricity Cost	628,966	49,094	449,323	21,363	593,645	33,357	181,449	8,176	295,508	29,067	186,343	0
Demand Charge	63,848	25,286	147,992	48,293	87,490	31,546	260,526	89,380	215,513	87,085	67,485	15,008
Fixed Monthly Charge	6,367	6,367	341	341	516	516	1,241	1,241	295	295	2,794	2,794
Cost ($/yr) FC supplies both space heating and Hot water	800,020	1,464,639	697,198	1,058,141	789,276	1,171,360	586,142	1,274,263	589,224	1,288,153	273,381	515,028
Capital Cost	0	264,941	0	264,941	0	264,941	0	264,941	0	264,941	0	264,941
O&M Cost	0	243,357	0	201,081	0	213,497	0	209,675	0	247,532	0	62,391
Scheduled Maintenance	0	3,000	0	3,000	0	3,000	0	3,000	0	3,000	0	3,000
Fuel Cost- FCS only	0	872,594	0	517,208	0	624,104	0	694,191	0	656,232	0	166,893
Residual Fuel	100,839	95,863	99,542	93,617	107,626	101,332	142,926	135,980	77,908	73,944	16,759	14,665
Electricity Cost	628,966	49,094	449,323	21,363	593,645	33,357	181,449	8,176	295,508	29,067	186,343	0
Demand Charge	63,848	25,286	147,992	48,293	87,490	31,546	260,526	89,380	215,513	87,085	67,485	15,008
Fixed Monthly Charge	6,367	6,367	341	341	516	516	1,241	1,241	295	295	2,794	2,794
Cost ($/yr) FC supplies Hot water only	800,020	1,560,502	697,198	1,149,843	789,276	1,272,294	586,142	1,406,583	589,224	1,362,097	273,381	529,693

Table F.7: Output results from use-phase model for hospital (4x250kW FC System). The first set of costs is for offset water heating and space heating and the second is for water heating only

Output results from use-phase model for hospital (250 kW FC System)												
	Phoenix, AZ		Minneapolis, MN		Chicago, IL		NYC, NY		Houston, TX		San Diego, CA	
Output	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell
FCS Power Utilization		100.0%		100.0%		100.0%		100.0%		100.0%		94.0%
FCS Heat Utilization WH+SH (WH only)		84.9% (4.2%)		100% (6.9%)		100% (6.5%)		100% (6.3%)		88.9% (4.5%)		18.1% (2.27%)
Total Electricity Demand (MWh/yr)	9,140		7,331		7,852		7,624		9,533		2,166	
Total Space Heating Demand (MWh/yr)	2,689		3,633		3,682		4,311		29,622		529	
Total Water Heating Demand (MWh/yr)	140		230		215		210		151		76	
Annual Generated Power by FC (MWh)		2,102		2,102		2,102		2,102		2,102		1,965
Annual Generated Heat by FC (MWh)		3,332		3,332		3,332		3,332		3,332		3,308
Capital Cost		5.30E+04		5.30E+04		5.30E+04		5.30E+04		5.30E+04		5.30E+04
O&M Cost		6.31E+04		6.31E+04		6.31E+04		6.31E+04		6.31E+04		5.89E+04
Scheduled Maintenance		3000		3000		3000		3000		3000		3000
Fuel Cost-FC Only		2.27E+05		1.64E+05		1.86E+05		2.11E+05		1.68E+05		1.64E+05
Residual Fuel	1.01E+05	10383.35	9.95E+04	2.19E+04	1.08E+05	1.82E+04	1.43E+05	3.76E+04	7.79E+04	1.02E+04	1.68E+04	0
Electricity Cost	6.29E+05	4.79E+05	4.49E+05	3.15E+05	5.94E+05	4.28E+05	1.81E+05	1.29E+05	2.96E+05	2.28E+05	1.86E+05	1.10E+04
Demand Charge	6.38E+04	5.26E+04	1.48E+05	1.19E+05	8.75E+04	7.11E+04	2.61E+05	2.11E+05	2.16E+05	1.79E+05	6.75E+04	2.35E+04
Fixed Monthly Charge	6366.96	6366.96	340.56	340.56	516	516	1240.56	1240.56	295.44	295.44	2794.44	2794.44
Cost ($/yr) FC supplies both space heating and Hot water	800,020	894,556	697,198	739,697	789,276	823,525	586,142	708,952	589,224	703,646	273,381	315,769
Capital Cost		5.30E+04		5.30E+04		5.30E+04		5.30E+04		5.30E+04		5.30E+04
O&M Cost		6.31E+04		6.31E+04		6.31E+04		6.31E+04		6.31E+04		5.89E+04
Scheduled Maintenance		3000		3000		3000		3000		3000		3000
Fuel Cost		2.27E+05		1.64E+05		1.86E+05		2.11E+05		1.68E+05		1.64E+05
Residual Fuel	1.01E+05	95,863	9.95E+04	9.36E+04	1.08E+05	1.01E+05	1.43E+05	1.36E+05	7.79E+04	7.39E+04	1.68E+04	1.47E+04
Electricity Cost	6.29E+05	4.79E+05	4.49E+05	3.15E+05	5.94E+05	4.28E+05	1.81E+05	1.29E+05	2.96E+05	2.28E+05	1.86E+05	1.10E+04
Demand Charge	6.38E+04	5.26E+04	1.48E+05	1.19E+05	8.75E+04	7.11E+04	2.61E+05	2.11E+05	2.16E+05	1.79E+05	6.75E+04	2.35E+04
Fixed Monthly Charge	6366.96	6366.96	340.56	340.56	516	516	1240.56	1240.56	295.44	295.44	2794.44	2794.44
Cost ($/yr) FC supplies Hot water only	800,020	980,036	697,198	811,394	789,276	906,640	586,142	807,346	589,224	767,410	273,381	330,434

Table F.8: Output results from use-phase model for hospital (250 kW FC System). The first set of costs is for offset water heating and space heating and the second is for water heating only.

Table F.9 shows the outputs results from the use-phase model for a small office building and 10kW FC system. For both a 5kW (not shown) and 10kW FCS, the cost of the fuel cell system case are signifiantly higher than for the No FCS case.

Output results from use-phase model for small office (10 kW FC system)										
	Phoenix, AZ		Minneapolis,		Chicago, IL		NYC, NY		Houston, TX	
Output	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell	No Fuel Cell	Fuel Cell
FCS-Power Utilization		53.6%		45.5%		45.2%		46.7%		55.5%
FCS-Heat Utilization SH+WH		4.2%		30.9%		23.4%		44.8%		9.8%
FCS-Heat Utilization (WH Only)		2.3%		2.6%		2.5%		2.5%		2.4%
Total Electricity Demand (kWh/yr)	63,223		45,748		45,912		52,462		71,456	
Total Space Heating Demand (kWh/yr)	2,454		36,606		26,956		54,794		9,627	
Total Water Heating Demand (kWh/yr)	2,942		3,370		3,296		3,232		3,093	
Annual Generated Power by FC (kWh)		45,087		38,235		38,013		39,267		46,662
Annual Generated Heat by FC (kWh)		83,395		75,600		75,778		73,516		85,936
Capital Cost	0	3,757	0	3,757	0	3,757	0	3,757	0	3,757
O&M Cost	0	1,353	0	1,147	0	1,140	0	1,178	0	1,400
Scheduled Maintenance	0	500	0	500	0	500	0	500	0	500
Fuel Cost-FC Only	0	5,816	0	3,776	0	4,282	0	4,819	0	4,413
Residual Fuel	192	1	1,030	143	884	75	1,923	538	335	20
Electricity Cost	5,226	1,403	4,929	659	3,472	482	1,249	275	2,215	708
Demand Charge	1,020	655	600	303	1,062	550	13,303	11,687	4,106	2,881
Fixed Monthly Charge	150	150	131	131	348	348	1,241	1,241	295	295
Cost ($/yr) FC supplies both space heating and Hot water	**6,588**	**13,634**	**6,690**	**10,417**	**5,767**	**11,135**	**17,715**	**23,995**	**6,951**	**13,975**
Capital Cost	0	3,757	0	3,757	0	3,757	0	3,757	0	3,757
O&M Cost	0	1,353	0	1,147	0	1,140	0	1,178	0	1,400
Scheduled Maintenance	0	500	0	500	0	500	0	500	0	500
Fuel Cost-FC Only	0	5,816	0	3,776	0	4,282	0	4,819	0	4,413
Residual Fuel	192	87	1,030	943	884	788	1,923	1,816	335	253
Electricity Cost	5,226	1,403	4,929	659	3,472	482	1,249	275	2,215	708
Demand Charge	1,020	655	600	303	1,062	550	13,303	11,687	4,106	2,881
Fixed Monthly Charge	150	150	131	131	348	348	1,241	1,241	295	295
Cost ($/yr) FC supplies Hot water only	**6,588**	**13,721**	**6,690**	**11,217**	**5,767**	**11,848**	**17,715**	**25,274**	**6,951**	**14,208**

Table F.9. Cost results for 10kW FCS in a small office building.

F.2. Life Cycle Impact Assessment (LCIA) Modeling

Fuel Cell, Heating Fuel and Electricity Emissions

Emissions from fuel cells, heating fuels, and electricity were calculated using Equations 1-20 below. The subscript "elec" indicates the emissions are associated with grid electricity. The subscript "fuel" indicates the emissions are associated with building heating fuels and the subscript "fcell" indicate the emissions are associated with the fuel cell. P is the electricity provided by the fuel cell [kWh] over a designated period of time. Emissions factors (EF) for fuel cells are labeled with a subscript "f", while EF for natural gas, fuel oil, propane, district heating, and electricity are noted with a subscript "ng", "o", "p", "dh", and "e", respectively. Emission factors for CO_2, CH_4, N_2O, NOx, SOx, PM10, and PM2.5 are labeled with subscripts "1", "2", "3", "4", "5", "6", and "7", respectively. H is the heat provided by the fuel cell [kWh], with "s" indicating space heating and "w" indicating water heating. The variable L is the fraction of building heating load supplied by a specific heating fuel, where the fuels are labeled as "elec" for electricity, "ng" for natural gas, "o" for fuel oil, "p" for propane, and "dh" for district heating.

$$CO2_{fuel}= H_s*(L_{ng\_s}*EF_{ng1} + L_{o\_s}*EF_{o1} + L_{p\_s}*EF_{p1} + L_{dh\_s}*EF_{dh1})+H_w*(L_{ng\_w}*EF_{ng1} + L_{o\_w}*EF_{o1} + L_{p\_w}*EF_{p1} + L_{dh\_w}*EF_{dh1}) \quad (1)$$

$$CH4_{fuel}= H_s*(L_{ng\_s}*EF_{ng2}+ L_{o\_s}*EF_{o2}+ L_{p\_s}*EF_{p2}+ L_{dh\_s}*EF_{dh2})+H_w*(L_{ng\_w}*EF_{ng2}+ L_{o\_w}*EF_{o2}+ L_{p\_w}*EF_{p2}+ L_{dh\_w}*EF_{dh2}) \quad (2)$$

$$N2O_{fuel}= H_s*(L_{ng\_s}*EF_{ng3}+ L_{o\_s}*EF_{o3}+ L_{p\_s}*EF_{p3}+ L_{dh\_s}*EF_{dh3})+H_w*(L_{ng\_w}*EF_{ng3}+ L_{o\_w}*EF_{o3}+ L_{p\_w}*EF_{p3}+ L_{dh\_w}*EF_{dh3}) \quad (3)$$

$$NOx_{fuel} = H_s*(L_{ng\_s}*EF_{ng4}+ L_{o\_s}*EF_{o4}+ L_{p\_s}*EF_{p4}+ L_{dh\_s}*EF_{dh4})+H_w*(L_{ng\_w}*EF_{ng4}+ L_{o\_w}*EF_{o4}+ L_{p\_w}*EF_{p4}+ L_{dh\_w}*EF_{dh4}) \quad (4)$$

$$SOx_{fuel} = H_s*(L_{ng\_s}*EF_{ng5}+ L_{o\_s}*EF_{o5}+ L_{p\_s}*EF_{p5}+ L_{dh\_s}*EF_{dh5})+H_w*(L_{ng\_w}*EF_{ng5}+ L_{o\_w}*EF_{o5}+ L_{p\_w}*EF_{p5}+ L_{dh\_w}*EF_{dh5}) \quad (5)$$

$$PM10_{fuel} = H_s*(L_{ng\_s}*EF_{ng6} + L_{o\_s}*EF_{o6}+ L_{p\_s}*EF_{p6}+ L_{dh\_s}*EF_{dh6})+H_w*(L_{ng\_w}*EF_{ng6\_} + L_{o\_w}*EF_{o6}+ L_{p\_w}*EF_{p6}+ L_{dh\_w}*EF_{dh6}) \quad (6)$$

$$PM2.5_{fuel} = H_s*(L_{ng\_s}*EF_{ng7} + L_{o\_s}*EF_{o7}+ L_{p\_s}*EF_{p7}+ L_{dh\_s}*EF_{dh7})+H_w*(L_{ng\_w}*EF_{ng7}+ L_{o\_w}*EF_{o7}+ L_{p\_w}*EF_{p7}+ L_{dh\_w}*EF_{dh7}) \quad (7)$$

$$CO2_{fcell}= P*EF_{f1} \quad (8)$$
$$CH4_{fcell}= P*EF_{f2} \quad (9)$$
$$N2O_{fcell}= P*EF_{f3} \quad (10)$$

$$CO2_{elec} = (P + H_s*L_{elec\_s} + H_w*L_{elec\_w})*EF_{e1} \quad (11)$$
$$CH4_{elec} = (P + H_s*L_{elec\_s} + H_w*L_{elec\_w})*EF_{e2} \quad (12)$$
$$N2O_{elec} = (P + H_s*L_{elec\_s} +H_w*L_{elec\_w})*EF_{e3} \quad (13)$$
$$NOx_{elec} = (P + H_s*L_{elec\_s} + H_w*L_{elec\_w})*EF_{e4} \quad (14)$$
$$SOx_{elec} = (P + H_s*L_{elec\_s} + H_w*L_{elec\_w})*EF_{e5} \quad (15)$$
$$PM10_{elec} = (P + H_s*L_{elec\_s} + H_w*L_{elec\_w})*EF_{e6} \quad (16)$$
$$PM2.5_{elec} = (P + H_s*L_{elec\_s} + H_w*L_{elec\_w})*EF_{e7} \quad (17)$$

Displaced Emissions from Fuel Consumption

Carbon dioxide (CO_2), CH_4, and N_2O emissions for natural gas, propane, and fuel oil (No. 2, 4, 6) combustion in commercial buildings were adopted from Appendix H of the 2011 EPA guide on reporting emissions (EPA, 2011). These values were cross-referenced with available city-specific information. Particulate matter size 10 and 2.5, NO_X, and SO_X emissions for fuel oils were also adopted from Tables 1.3-1 and 1.3-4 of an EPA report (EIA, 2013). PM_{10}, NO_X, and SO_X emissions for natural gas were taken from Table 1.4-1 and 1.4-2 of the same report.

CO_2 values were provided for propane from the 2011 EIA guide on reporting emissions. CH_4 and N_2O emissions were taken from a New York City commercial buildings report. We assumed propane has negligible NO_X, SO_X, and PM emissions. CO_2, CH_4, and N_2O were converted to GHG using characterization factors of 1, 21, and 310, respectively.

We assumed that district heating was generated from natural gas. The power and heat from this natural gas was not counted as a displaced emission because we assumed that it would occur regardless of fuel cell adoption.

Original Fuel Consumption in Commercial Buildings

In this analysis two building types examined were hospitals (>=200,000 sq. ft), and small hotels (<50 sq. ft). However, buildings are characterized by their size, primary use, and location. These size divisions are the closest breaks to the size breaks used in a National Renewable Energy Laboratory (NREL) study [1]. In this analysis, we used the 2003 Commercial Buildings Energy Consumption Survey (CBECS) database to estimate data on energy and fuel consumption (electricity, natural gas, and fuel oil) (CBECS, 2003). Table F.10 summarizes all energy constants used in the analysis (E_x; where subscript x represents energy type)

E_{Total}	Total energy consumption
E_E	Electricity consumption
E_{NG}	Natural gas consumption
E_{FO}	Fuel oil consumption
E_W	Energy to water heating end use
E_S	Energy to space heating end use
E_C	Energy to cooling end use
E_{DH}	District heating consumption
E_P	Propane consumption

Table F.10. Table of Constants

For many cases:

$$E_{Total} > E_E + E_{NG} + E_{FO} \tag{18}$$

This is because E_{total} also includes district heating (E_{DH}) and propane (E_P), but CBECS does not include exact values for these two categories. Initially we estimated the energy from district heating from an EIA report that gave district heating per building per region (EIA). This 1999 data was scaled to 2013 values using 67 Gft^3 as the floorspace of commercial buildings in 1999 (CBECS, 2003). Values were scaled to 2013 using a scaling ratio of total floorspace in 2013 divided by total floorspace in 2003 for commercial buildings (82.9/71.7 in Gft^3). CBECS data was scaled to a city using a scaling ratio of 2010_Population_City/2010_Population_Region. The 2010 populations for cities, states, and regions were taken from the 2010 census data. We compared these values to (E_{Total} - E_E - E_{NG} - E_{FO}) and took the minimum value. The remaining total energy consumed in the building was allocated to propane so that:

$$E_{Total} - E_E - E_{NG} - E_{FO} - E_{DH} = E_P \tag{19}$$

We developed an allocation scheme to match fuel consumption to end use for each building and region.

a. Initially, we assumed 90% of E_{NG} is used for water heating (E_W) and space heating (E_S). (This is a reasonable assumption based on data from California http://energyalmanac.ca.gov/naturalgas/residential_use.html -- and CA is a mild climate for space heating)
b. We assumed 100% of E_{DH} and E_{FO} were used for heating.
c. We assumed the remaining fraction of heating was met with electricity so that:

$$E_W + E_S - 0.9 * E_{NG} - E_{FO} - E_{DH} = E_E \tag{20}$$

i. In one case (Minneapolis Large Office) there was not enough electricity. After allocating electricity to lighting, computer, and other purely electrical end uses, it was clear that another fuel was used for heating. We assumed this was propane E_P.

d. We reduced the fraction in (a) above if natural gas supplied to heating in cases where 90% of E_{NG} exceeded $E_W + E_S$.
e. We assumed that all cooling is met with electricity (U.S. Census Bureau. 2010)

This approach provided us with the annual average consumption of natural gas, electricity, fuel oil, district heat, and propane for cooling, and water and space heating. The fraction of heat provided by each of the different fuel types is shown in Figures 7.5 and 7.6.

Monetized marginal environmental and human health impacts of FCS operation scenarios for a 1MW or 250kW FC system in a hospital are shown in Tables F.11-F.14.

LCIA Results for hospital (1 MW FC system)						
Output	**Phoenix**	**Minneapolis**	**Chicago**	**New York City**	**Houston**	**San Diego**
Annual Generated Power by FC (MWh)	8,112	6,703	7,117	6,989	8,251	2080
Annual Generated Heat by FC (MWh)	13,282	11,580	12,114	12,012	13,305	4,938
Avoided GHG [tCO2e/y]	-223	2239	2210	155	76	-64
Avoided Nox [tNOx/y]	3.01	7.74	7.93	2.86	3.04	0.76
Avoided Sox [tSOx/y]	1.60	14.43	26.64	4.62	3.36	0.41
Avoided PM10 [t/y]	0.0356	0.0440	0.0272	0.0542	0.0326	0.00402
Avoided PM2.5 [t/y]	0.00375	0.00822	0.00141	0.01448	0.00168	0.00040
GHG credit at $44/ton CO2 ($/kWhe)	-0.0012	0.015	0.014	0.0010	0.0004	-0.0013
Health, Environmental Savings ($/kWhe)	0.0012	0.017	0.028	0.0090	0.002	0.0019

Table F.11. Monetized marginal environmental and human health impacts of FCS operation scenarios for a 1MW FC system in a hospital compared to grid-based electricity and conventional heating. The FCS system is assumed to offset water heating and space heating.

LCIA Results for hospital (1 MW FC system)						
Output	**Phoenix**	**Minneapolis**	**Chicago**	**New York City**	**Houston**	**San Diego**
Annual Generated Power by FC (MWh)	8,112	6,703	7,117	6,989	8,251	2079.7
Annual Generated Heat by FC (MWh)	13,282	11,580	12,114	12,012	13,305	4,938
Avoided GHG [tCO2e/y]	-696	1768	1175	-564	-372	-170
Avoided Nox [tNOx/y]	2.62	7.33	6.76	2.27	2.66	0.68
Avoided Sox [tSOx/y]	1.47	14.16	23.60	3.88	3.30	0.38
Avoided PM10 [t/y]	0.0018	0.0026	0.0016	0.0026	0.0017	0.00050
Avoided PM2.5 [t/y]	0.00019	0.00049	0.00008	0.00070	0.00009	0.00005
GHG credit at $44/ton CO_2 ($/kWhe)	-0.0038	0.012	0.0073	-0.0036	-0.002	-0.0036
Health, Environmental Savings ($/kWhe)	0.0009	0.016	0.0251	0.0044	0.002	0.0014

Table. F.12. Monetized marginal environmental and human health impacts of FCS operation scenarios for a 1MW FC system in a hospital compared to grid-based electricity and conventional heating. The FCS system is assumed to only offset water heating.

LCIA Results for hospital (250 kW FC System)						
Output	**Phoenix**	**Minneapolis**	**Chicago**	**New York City**	**Houston**	**San Diego**
Annual Generated Power by FC (MWh)	2,102	2,102	2,102	2,102	2,102	1964.7
Annual Generated Heat by FC (MWh)	3,332	3,332	3,332	3,332	3,332	3308
Avoided GHG [tCO2e/y]	311	977	1323	404	371	-53

Avoided Nox [tNOx/y]	1.09	2.67	3.10	1.16	1.07	0.72
Avoided Sox [tSOx/y]	0.52	4.68	9.84	1.75	0.90	0.39
Avoided PM10 [t/y]	0.0356	0.0380	0.0246	0.0419	0.0326	0.00402
Avoided PM2.5 [t/y]	0.00375	0.0071	0.00128	0.01119	0.00168	0.00040
GHG credit at $44/ton CO2 ($/kWhe)	0.0065	0.0204	0.028	0.008	0.0078	-0.0012
Health, Environmental Savings ($/kWhe)	0.0022	0.0206	0.036	0.017	0.0034	0.0019

Table F.13. Monetized marginal environmental and human health impacts of FCS operation scenarios for a 250kW FC system in a hospital compared to grid-based electricity and conventional heating. The FCS system is assumed to offset water heating and space heating.

LCIA Results for hospital (250 kW FC System)						
Output	**Phoenix**	**Minneapolis**	**Chicago**	**New York City**	**Houston**	**San Diego**
Annual Generated Power by FC (MWh)	2,102	2,102	2,102	2,102	2,102	1964.7
Annual Generated Heat by FC (MWh)	3,332	3,332	3,332	3,332	3,332	3308
Avoided GHG [tCO2e/y]	-162	575	392	-144	-77	-160
Avoided Nox [tNOx/y]	0.69	2.32	2.05	0.70	0.69	0.64
Avoided Sox [tSOx/y]	0.39	4.45	7.10	1.19	0.84	0.36
Avoided PM10 [t/y]	0.0018	0.0026	0.0016	0.0026	0.0017	0.00050
Avoided PM2.5 [t/y]	0.00019	0.0005	0.00008	0.00070	0.00009	0.00005
GHG credit at $44/ton CO_2 ($/kWhe)	-0.0034	0.0120	0.0082	-0.0030	-0.0016	-0.0036
Health, Environmental Savings ($/kWhe)	0.0009	0.0160	0.0256	0.0049	0.0017	0.0014

Table F.14. Monetized marginal environmental and human health impacts of FCS operation scenarios for a 250kW FC system in a hospital compared to grid-based electricity and conventional heating. The FCS system is assumed to only offset water heating.

3. Total Cost of Ownership Modeling

Output results from use-phase model for hospital (1 MW FC system)												
Output	Phoenix, AZ		Minneapolis, MN		Chicago, IL		NYC, NY		Houston, TX		San Diego, CA	
	No FCS	Fuel Cell	No FCS	Fuel Cell	No FCS	Fuel Cell	No FCS	Fuel Cell	No FCS	Fuel Cell	No FCS	Fuel Cell
FC System Utilization		96.5%		79.7%		84.6%		83.1%		98.1%		**0.247**
Total Electricity Demand (MWh/yr)	9,140	9,140	7,331	7,331	7,852	7,852	7,624	7,624	9,533	9,533	2166.4	2166.4
Total Space Heating Demand (MWh/yr)	2,689		3,633		3,467		4,102		2812		528.8	
Total Water Heating Demand (MWh/yr)	140		230		215		210		151		75.5	
Annual Generated Power by FC (MWh)		8,112		6,703		7,117		6,989		8,251		2079.7
FC fraction of Electricity Demand		89%		91%		91%		92%		87%		96%
Annual Generated Heat by FC (MWh)		12,707		10,819		11,371		11,213		12,853		4737.5
Capital Cost ($/yr)		264941		264,941		2.65E+05		264941		264941		264941
O&M Cost ($/yr)		243357		201,081		2.13E+05		209675		247532		62391
Scheduled Maintenance ($/yr)		3000		3,000		3.00E+03		3000		3000		3000
Fuel Cost for Fuel Cell ($/yr)		872594		517268		624171		694128		656207		168308
Fuel Cost for Conv. Heating ($/yr)	100839	0	99554	1838	107637	382	142913	3513	77905	0	16901	0
Purchased Electricity Energy Cost ($/yr)	628966	47130	449323	20,509	593645	3.20E+04	181449	7849	295508	27905	186343	0
Demand Charge ($/yr)	63848	25286	147992	48293	87490	31546	260526	89380	215513	87085	67485	15008
Fixed Charge, Electricity ($/yr)	6367	6367	341	341	516	516	1241	1241	295	295	2794	2794
Total Electricity Cost ($/yr)	699181	1462675	597656	1055432	681651	1169694	443216	1270214	511316	1286965	256622	516442
Total Cost of Electricity ($/kWh)	0.076	0.160	0.082	0.144	0.087	0.149	0.058	0.167	0.054	0.135	0.118	0.238
Purchased Electricity Cost ($/kWh)	0.076	0.077	0.082	0.110	0.087	0.087	0.058	0.155	0.054	0.090	0.118	0.205
LCOE of FC power ($/kWh)		**0.171**		**0.147**		**0.155**		**0.168**		**0.142**		**0.240**
Fuel savings from conventional heating ($/yr)		100839		97716		107255		139400		77905		16901
Fuel savings per kWh ($/kWh)		0.0124		0.0146		0.0151		0.0199		0.0094		0.0081
LCOE of FC power with fuel savings ($/kWh)		**0.158**		**0.133**		**0.140**		**0.148**		**0.133**		**0.232**
GHG credit at $44/ton CO_2 ($/kWh)		-0.0005		0.0160		0.0140		0.0020		0.0022		-0.0009
Health, Environmental Savings ($/kWh)		0.0013		0.0180		0.0290		0.0100		0.0011		0.0020
LCOE with TCO Savings for Fuel Cell Power ($/kWh)		**0.157**		**0.099**		**0.097**		**0.136**		**0.129**		**0.231**
LCOE with TCO Savings for FC and Purchased Power, ($/kWh)		0.148		0.100		0.096		0.137		0.124		0.230

Table F.15. Levelized cost of electricity with total cost of ownership savings for hospitals and 1MW (4x 250kW) FC systems providing hot water and space heating compared to grid-based cost of electricity.

Output results from use-phase model for hospital (1 MW FC system)												
Output	**Phoenix, AZ**		**Minneapolis, MN**		**Chicago, IL**		**NYC, NY**		**Houston, TX**		**San Diego, CA**	
	No FCS	**Fuel Cell**	**No FCS**	**Fuel Cell**	**No FCS**	**Fuel Cell**	**No FCS**	**Fuel Cell**	**No FCS**	**Fuel Cell**	**No FCS**	**Fuel Cell**
FC System Utilization		96.5%		79.7%		84.6%		83.1%		98.1%		**0.247**
Total Electricity Demand (MWh/yr)	9,140	9,140	7,331	7,331	7,852	7,852	7,624	7,624	9,533	9,533	2166.4	2166.4
Total Space Heating Demand (MWh/yr)	2,689		3,633		3,467		4,102		2812		528.8	
Total Water Heating Demand (MWh/yr)	140		230		215		210		151		75.5	
Annual Generated Power by FC (MWh)		8,112		6,703		7,117		6,989		8,251		2079.7
FC fraction of Electricity Demand		89%		91%		91%		92%		87%		96%
Annual Generated Heat by FC (MWh)		12,707		10,819		11,371		11,213		12,853		4737.5
Capital Cost ($/yr)		264941		264,941		2.65E+05		264941		264941		264941
O&M Cost ($/yr)		243357		201,081		2.13E+05		209675		247532		62391
Scheduled Maintenance ($/yr)		3000		3,000		3.00E+03		3000		3000		3000
Fuel Cost for Fuel Cell ($/yr)		872594		517268		624171		694128		656207		166893
Fuel Cost for Conv. Heating ($/yr)	100839	92028	99554	89883	107637	97289	142913	130529	77905	70984	16759	14078
Purchased Electricity Energy Cost ($/yr)	628966	47130	449323	20,509	593645	3.20E+04	181449	7849	295508	27905	186343	0
Demand Charge ($/yr)	63848	25286	147992	48293	87490	31546	260526	89380	215513	87085	67485	15008
Fixed Charge, Electricity ($/yr)	6367	6367	341	341	516	516	1241	1241	295	295	2794	2794
Total Electricity Cost ($/yr)	699181	1462675	597656	1055432	681651	1169694	443216	1270214	511316	1286965	256622	515028
Total Cost of Electricity ($/kWh)	0.076	0.160	0.082	0.144	0.087	0.149	0.058	0.167	0.054	0.135	0.118	0.238
Purchased Electricity Cost ($/kWh)	0.076	0.077	0.082	0.110	0.087	0.087	0.058	0.155	0.054	0.090	0.118	0.205
LCOE of FC power ($/kWh)		**0.171**		**0.147**		**0.155**		**0.168**		**0.142**		**0.239**
Fuel savings from conventional heating ($/yr)		8810		9671		10348		12384		6921		2681
Fuel savings per kWh ($/kWh)		0.0011		0.0014		0.0015		0.0018		0.0008		0.0013
LCOE of FC power with fuel savings ($/kWh)		**0.170**		**0.146**		**0.154**		**0.166**		**0.141**		**0.238**
GHG credit at $44/ton CO_2 ($/kWh)		-0.004		0.012		0.007		-0.003		-0.002		-0.003
Health, Environmental Savings ($/kWh)		0.001		0.016		0.025		0.004		0.002		0.001
LCOE with TCO Savings for Fuel Cell Power ($/kWh)		**0.172**		**0.118**		**0.121**		**0.165**		**0.141**		**0.240**
LCOE with TCO Savings for FC and Purchased Power, ($/kWh)		0.162		0.117		0.118		0.164		0.134		0.238

Table F.16. Levelized cost of electricity with total cost of ownership savings for hospitals and 1MW (4x 250kW) FC systems providing hot water only compared to grid-based cost of electricity.

Output results from use-phase model for hospital (250 kW FC System)												
Output	**Phoenix, AZ**		**Minneapolis, MN**		**Chicago, IL**		**NYC, NY**		**Houston, TX**		**San Diego, CA**	
	No FCS	**Fuel Cell**	**No FCS**	**Fuel Cell**	**No FCS**	**Fuel Cell**	**No FCS**	**Fuel Cell**	**No FCS**	**Fuel Cell**	**No FCS**	**Fuel Cell**
FC System Utilization		100.0%		100.0%		100.0%		100.0%		100.0%		**0.94**
Total Electricity Demand (MWh/yr)	9,140	9,140	7,331	7,331	7,852	7,852	7,624	7,624	9,533	9,533	2166.4	2166.4
Total Space Heating Demand (MWh/yr)	2,689		3,633		3,682		4,311		2812		528.8	
Total Water Heating Demand (MWh/yr)	140		230		215		210		151		75.5	
Annual Generated Power by FC (MWh)		2,102		2,102		2,102		2,102		2,102		1965
FC fraction of Electricity Demand		23%		29%		27%		28%		22%		91%
Annual Generated Heat by FC (MWh)		3,177		3,177		3,177		3,177		3,177		3108.3
Capital Cost ($/yr)		52988		52988		52988		52988		52988		52988
O&M Cost ($/yr)		63072		63072		63072		63072		63072		58940
Scheduled Maintenance ($/yr)		3000		3000		3000		3000		3000		3000
Fuel Cost for Fuel Cell ($/yr)		227123		164197		186241		211177		167549		163584
Fuel Cost for Conv. Heating ($/yr)	100839	10117	99554	21406	107637	17803	142913	36728	77905	9922	16759	0
Purchased Electricity Energy Cost ($/yr)	628966	465882	449323	306537	593645	416653	181449	125768	295508	221419	186343	10662
Demand Charge ($/yr)	63848	52624	147992	119111	87490	71101	260526	210542	215513	178937	67485	23511
Fixed Charge, Electricity ($/yr)	6367	6367	341	341	516	516	1241	1241	295	295	2794	2794
Total Electricity Cost ($/yr)	699181	871056	597656	709246	681651	793572	443216	667787	511316	687261	256622	315480
Total Cost of Electricity ($/kWh)	0.076	0.095	0.082	0.097	0.087	0.101	0.058	0.088	0.054	0.072	0.118	0.146
Purchased Electricity Cost ($/kWh)	0.076	0.075	0.082	0.081	0.087	0.085	0.058	0.061	0.054	0.054	0.118	0.183
LCOE of FC power ($/kWh)		**0.165**		**0.135**		**0.145**		**0.157**		**0.136**		**0.142**
Fuel savings from conventional heating ($/yr)		90722		78147		89834		106184		67983		16759
Fuel savings per kWh ($/kWh)		0.0432		0.0372		0.0427		0.0505		0.0323		0.0085
LCOE of FC power with fuel savings ($/kWh)		**0.122**		**0.098**		**0.103**		**0.107**		**0.104**		**0.133**
GHG credit at $44/ton CO_2 ($/kWh)		0.0107		0.0220		0.0290		0.0100		0.0112		-0.0008
Health, Environmental Savings ($/kWh)		0.0027		0.0220		0.0360		0.0190		0.0041		0.0020
LCOE with TCO Savings for Fuel Cell Power ($/kWh)		**0.108**		**0.054**		**0.038**		**0.078**		**0.089**		**0.132**
LCOE with TCO Savings for FC and Purchased Power, ($/kWh)		0.082		0.073		0.072		0.066		0.062		0.137

Table F.17. Levelized cost of electricity with total cost of ownership savings for hospitals and 250kW FC systems providing hot water and space heating compared to grid-based cost of electricity.

Output results from use-phase model for hospital (250 kW FC System)												
Output	Phoenix, AZ		Minneapolis, MN		Chicago, IL		NYC, NY		Houston, TX		San Diego, CA	
	No FCS	Fuel Cell	No FCS	Fuel Cell	No FCS	Fuel Cell	No FCS	Fuel Cell	No FCS	Fuel Cell	No FCS	Fuel Cell
FC System Utilization		100.0%		100.0%		100.0%		100.0%		100.0%		**0.94**
Total Electricity Demand (MWh/yr)	9,140	9,140	7,331	7,331	7,852	7,852	7,624	7,624	9,533	9,533	2166.4	2166.4
Total Space Heating Demand (MWh/yr)	2,689		3,633		3,682		4,311		2812		528.8	
Total Water Heating Demand (MWh/yr)	140		230		215		210		151		75.5	
Annual Generated Power by FC (MWh)		2,102		2,102		2,102		2,102		2,102		1965
FC fraction of Electricity Demand		23%		29%		27%		28%		22%		91%
Annual Generated Heat by FC (MWh)		3,177		3,177		3,177		3,177		3,177		3108.3
Capital Cost ($/yr)		52988		52988		52988		52988		52988		52988
O&M Cost ($/yr)		63072		63072		63072		63072		63072		58940
Scheduled Maintenance ($/yr)		3000		3000		3000		3000		3000		3000
Fuel Cost for Fuel Cell ($/yr)		227123		164197		186241		211177		167549		163584
Fuel Cost for Conv. Heating ($/yr)	100839	93422	99554	91274	107637	98823	142913	132576	77905	72074	16759	14283
Purchased Electricity Energy Cost ($/yr)	628966	465882	449323	306537	593645	416653	181449	125768	295508	221419	186343	10662
Demand Charge ($/yr)	63848	52624	147992	119111	87490	71101	260526	210542	215513	178937	67485	23511
Fixed Charge, Electricity ($/yr)	6367	6367	341	341	516	516	1241	1241	295	295	2794	2794
Total Electricity Cost ($/yr)	699181	871056	597656	709246	681651	793572	443216	667787	511316	687261	256622	315480
Total Cost of Electricity ($/kWh)	0.076	0.095	0.082	0.097	0.087	0.101	0.058	0.088	0.054	0.072	0.118	0.146
Purchased Electricity Cost ($/kWh)	0.076	0.075	0.082	0.081	0.087	0.085	0.058	0.061	0.054	0.054	0.118	0.183
LCOE of FC power ($/kWh)		**0.165**		**0.135**		**0.145**		**0.157**		**0.136**		**0.142**
Fuel savings from conventional heating ($/yr)		7417		8280		8814		10336		5830		2476
Fuel savings per kWh ($/kWh)		0.0035		0.0039		0.0042		0.0049		0.0028		0.0013
LCOE of FC power with fuel savings ($/kWh)		**0.161**		**0.131**		**0.141**		**0.152**		**0.134**		**0.140**
GHG credit at $44/ton CO_2 ($/kWh)		-0.003		0.012		0.008		-0.003		-0.001		-0.003
Health, Environmental Savings ($/kWh)		0.001		0.016		0.026		0.005		0.002		0.002
LCOE with TCO Savings for Fuel Cell Power ($/kWh)		**0.163**		**0.103**		**0.107**		**0.150**		**0.133**		**0.142**
LCOE with TCO Savings for FC and Purchased Power, ($/kWh)		0.095		0.088		0.091		0.086		0.071		0.146

Table F.18. Levelized cost of electricity with total cost of ownership savings for hospitals and 250kW FC systems providing hot water only compared to grid-based cost of electricity.

For a 1MW FCS in hospitals and offset water heating only (Table F.16), Minneapolis and Chicago realize about 20% in LCOE savings for FC power but the total cost of electricity is still above the no FCS case ($0.117/kWh in Minneapolis vs. $0.082/kWh and $0.118/kWh in Chicago vs. $0.087/kWh). The hospital in San Diego has a much lower demand for power and heating than the other cities since it is from a California data base of buildings (CBECs) whereas the other cities are from the NREL data set. Thus, the 1MW system is grossly oversized for the San Diego case but the 250kW system is more reasonably sized.

For a 250kW FCS in hospitals and offset water heating only (Table F.18), the LCOE for FC and purchased power is brought within competitive range of the no fuel cell case in Minneapolis and Chicago at $0.088/kWh vs. $0.082 in Minneapolis and $0.091/kWh vs. $0.087/kWh in Chicago.