(DISCO-H2)

Model Concept Development

Final Report
for
IEA – International Energy Agency
HIA – Hydrogen Implementing Agreement

Task 29: Distributed and Community Hydrogen (DISCO-H2)
Subtask 3: Model Concept Development

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Task 29 (DISCO-H2) Subtask 3 Final Report

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<td>148</td>
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1. Executive Summary

The International Energy Agency (IEA) – Hydrogen Implementing Agreement (HIA) has established Task 29: Distributed Community Hydrogen (DISCO-H2). This Task was operated from the beginning of 2011 to the end of 2014 to progress the optimization and replication of “green” hydrogen within distributed and community energy systems. This Task would be accomplished by identifying situations where the use of hydrogen is appropriate and assessing the technical, environmental, economic, and social benefits of such systems.

Subtask 3 (ST3) – Model concept development, is the follow-up to subtask 2 (ST2). In ST2, based on the project survey and data collection, six projects were selected for detailed analysis in ST3; these focus on the following types of communities:

- two islands/rural
- two urban
- two industrial/commercial applications

In ST3, the final goal is to develop three generic models of the distributed and community hydrogen system (DISCO-H2) concept so as to represent the three categories above. These concepts would be designed to be scaled up in light of concept replication and market penetration.

According to the planned logical flow (see Figure. 3.1), the detailed analysis of distributed hydrogen systems has been executed for the six selected projects listed above. The system components of objective projects in ST3 are listed in Table 1.1.

Table 1.1. System components of six projects selected for detailed analysis.

<table>
<thead>
<tr>
<th>#</th>
<th>Project name</th>
<th>AC grid</th>
<th>DC bus</th>
<th>Natural gas grid</th>
<th>Renewable energy sources</th>
<th>H₂ production</th>
<th>Hydrogen storage</th>
<th>Power production with H₂</th>
<th>Thermal storage</th>
<th>Other H₂ components</th>
<th>Electricity usage</th>
<th>Heat usage</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Lolland residential CHP</td>
<td>√</td>
<td></td>
<td></td>
<td>Wind</td>
<td>Alkaline electrolyzer</td>
<td>Pressurized tank (2.3 kg@6 bar)</td>
<td>PEMFC (1.5 kW×10)</td>
<td>Hot water tank (200 L)</td>
<td>Hydrogen pipeline</td>
<td>Residential ←</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Myrte</td>
<td>√</td>
<td></td>
<td></td>
<td>PV</td>
<td>PEM electrolyzer</td>
<td>Pressurized tank (125 kg@35 bar)</td>
<td>PEMFC (100+60 kW)</td>
<td>- *</td>
<td>-</td>
<td>Grid ←</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Japanese residential CHP</td>
<td>√</td>
<td></td>
<td></td>
<td>Reforming</td>
<td>-</td>
<td>PEMFC (1 kW×3,307)</td>
<td>Hot water tank (150 L)</td>
<td>-</td>
<td>Residential ←</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Octagon</td>
<td>√</td>
<td></td>
<td></td>
<td>Reforming</td>
<td>-</td>
<td>PAFC (400 kW)</td>
<td>Hot water tank</td>
<td>-</td>
<td>Residential ←</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>FedEx Forklift</td>
<td>-</td>
<td></td>
<td></td>
<td>Reforming</td>
<td>Liquid-H₂ tank (1,600 kg)</td>
<td>PEMFC (12 kW×40)</td>
<td>-</td>
<td>-</td>
<td>Forklift ←</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Hydrogen Office</td>
<td>√</td>
<td></td>
<td></td>
<td>Wind</td>
<td>Alkaline electrolyzer</td>
<td>Pressurized tank (10 kg@12 bar)</td>
<td>PEMFC (30 kW) (Heat pump)</td>
<td>-</td>
<td>Hydrogen burner</td>
<td>Office building ←</td>
<td></td>
</tr>
</tbody>
</table>

*: A thermal management system using water is deployed for fundamental testing.
Initially, based on preliminary information, a SWOT (strength, weakness, opportunity, and threats) analysis was performed for each project from the aspects of economic, environment/technical, community/social, and regulatory. Based on this analysis, the findings in community/social and regulatory aspects are summarized and reviewed here. Due to the lack of codes and standards in rural/island communities, it has taken a long time to obtain the permission of relevant authorities to proceed with installation. Fortunately, the community inhabitants were positive and friendly toward the installation and operation of hydrogen systems. The next step will be to show them the apparent benefits, such as reduced energy costs or increased employment. In urban communities, lack of codes and standards is also a problem in certain cases. In addition, education is important not only for engineers but also for users. In industrial/commercial communities, operational and maintenance support provided by suppliers were highly evaluated by the users.

Software analysis provided a host of findings relating to the economic and environment/technical aspects. In rural/island communities, the hydrogen storage system based on renewable energy sources (RES) is a major candidate. However, achieving economic feasibility with this kind of system is considerably difficult at present. In addition, the round-trip efficiency of the hydrogen system (electrolysis – storage – power generation) is about 40% at the highest, and the hydrogen system needs a specific objective such as load leveling or backup power. In urban communities, a small-scale FC-based CHP system has been commercialized and is close to achieving economic feasibility. However, using hydrocarbons as a fuel for CHP means that CO₂ emissions cannot be avoided, and the reduction of CO₂ emissions must be discussed carefully. In industrial/commercial communities, there are several applications where distributed hydrogen systems can be introduced, such as FC-based cogeneration, FC-based backup power and FC-powered forklifts. In the case of FC-powered forklifts in a warehouse, a lower charging frequency (longer driving distance per charge) and shorter charging (fueling) time are major advantages over battery-powered forklifts. A cost comparison of total ownership between these two kinds of forklift revealed that FC-powered forklifts are already competitive with battery-powered forklifts.

In addition, “Project Follow-Up Questions” was prepared and delivered to each project respondent. This questionnaire focused mainly on the community/social and regulatory aspects. Unfortunately, only a few responses were received, and analysis of these aspects has not been sufficient.

Finally, subtask 3 concluded with proposals for model concepts for each community category: rural/island, urban, industrial/commercial. The model concept for rural/island communities was based on a small-scale grid and unstable RES such as wind and PV. A hydrogen system installed in such a scenario would play the role of peak shaving and peak shift so as to stabilize the electricity grid and increase the capacity of RES in the communities. Conversely, the model for urban community did not consider RES and relied fully on the existing electricity and gas grids. In this community, a natural gas-fueled FC-based CHP system was considered as a promising application, though this should not be called a hydrogen system in the strict sense. As for industrial/commercial communities, because the hydrogen application was distributed over a wide area, it was difficult to create a concrete concept. A cost-effective method of producing and delivering hydrogen would be critical regardless of application type.
2. Introduction

2.1 Background

Task 29: Distributed Community Hydrogen (DISCO-H2) was proposed as follow-on to Task 18: Integrated Systems Evaluation as a further activity conducted under the International Energy Agency (IEA) – Hydrogen Implementing Agreement (HIA). The proposal was approved at the executive committee (ExCo) meeting of HIA in November 2010, and the Task started in early 2011. The proposal is to study the integration of hydrogen systems with electricity and other energy and mobility networks. The Task should have considerable industrial input and create impetus toward commercialization of hydrogen systems.

2.2 Objectives

To progress the optimization and replication of “green” hydrogen within distributed and community energy systems, this Task would be accomplished by identifying situations where the use of hydrogen is appropriate and assessing the technical, environmental, economic, and social benefits of such systems. Analysis includes:

- cost-benefit analysis
- business case and market research
- identification of technical benefits and gaps
- materials for education and raising awareness
- materials to help planners and regulatory authorities facilitate incorporation of hydrogen systems within energy networks

This should form part of the foundation for commercialization efforts and favor new job opportunities.

2.2 Scope of Task 29: DISCO-H2

This Task will be successful when the technical, economic, social, and environmental benefits of hydrogen in communities are evident and the Task has played a role in helping to implement such systems, leading to replication or mass production. To this end, the Task aims to take a holistic view of low-carbon energy networks and to identify the appropriate situations where integrating hydrogen systems within such networks offers added value.

The Task has focused on hydrogen applications in energy communities and distributed systems mostly involving stationary applications, but it also looked at potential benefits for transportation. An “energy community” is defined as a group of interacting people living in a common location that features a shared geographical location and energy needs.

The scope of distributed and community hydrogen covers:

- hydrogen applications in island and rural communities
- hydrogen applications in urban communities
The hydrogen used should be produced at the local level (i.e., distributed) rather than at a centralized industrial site. Communities to be considered should have up to 1000 people, and the total installed power capacity of the hydrogen energy technologies (both producing and consuming hydrogen) in the communities should not exceed 500 kW.

The Task would be broken down into the following subtasks (ST), which would be articulated in various activities:

Subtasks (suggestions in parentheses):

1. Management
   1.1 Management and reporting
2. Analysis and selection
   2.1 Community identification
   2.2 Data collection (in relation to economic, social-regulatory, environmental, and technical areas)
   2.3 Project selection
3. Model concept development
   3.1 Analysis of island/rural projects
   3.2 Analysis of urban projects
   3.3 Analysis of industrial/commercial projects
4. Concept replicability
   4.1 Technology readiness assessment
   4.2 Market readiness assessment
5. Dissemination
   5.1 Dissemination of task results
   5.2 Scientific community
   5.3 Industrial sector
   5.4 Regulatory authorities

Figure 2.1 shows the logical flow of subtasks. The main flow of the overall Task lies in ST2, ST3, and ST4. ST2 surveys the projects worldwide and selects those that will be further analyzed in ST3. ST3 focuses on the projects selected in ST2 and develops and defines three main concept models, one for each project category. ST4 studies the potential for the concept replicability among selected stakeholders by suggesting application sectors in order to achieve market penetration.

In the long term, whole cities may integrate hydrogen into their energy networks. However, DISCO-H2 will concentrate on developments at the subdivision level or smaller, as it is envisaged that this is how distributed and community hydrogen systems will be built up. A full range of energy applications for which hydrogen may be used shall be considered; examples include heat, power, transport, and cooking. This will allow studies of how hydrogen
can be used as a vector to bridge different energy networks and manage peaks of load consumption and generation. Thus, electrolyzers, reformers, fuel cells, ICEs, hydrogen burners, and renewable energy generation systems are all likely to be components. DISCO-H2 will take a holistic view of how these components can be integrated in and complement existing energy networks. The investigated sources of hydrogen would preferably be those that are renewable, but other sources like reforming of natural gas or wastes will be taken into consideration.

Following a review of various projects, six projects will be selected for detailed analysis in ST3. These will consist of:

- two islands/rural
- two urban
- two industrial/commercial applications

From these six projects, three generic models of the distributed and community H₂ concept will be developed, one for each of the categories above. These concepts will be designed to be scaled up in light of concept replication and market penetration.
3 System evaluation methodology in subtask 3

3.1 General methodology

A final goal of subtask 3 is the establishment of a model concept for each category. Figure 3.1 shows the work flow in ST3. At first, in order to grasp the outline of each selected project, a strengths, weaknesses, opportunities, and threats (SWOT) analysis will be performed based on published literature, interviews, and/or questionnaires to project organizers. Two routes have recently been prepared to reach the goal: one is a computer software analysis focusing on the economic and environment/technical aspects, and the other is a questionnaire focusing on the social (community) and regulatory (codes and standards) aspects.

Based on the outcomes from subtask 2, subtask 3 will develop and define three main concept models, one for each project category described above, that can be reproduced and replicated for distributed and community hydrogen applications. Each of the three categories will be the subject of a dedicated activity.

Figure 3.1. Work flow in subtask 3.

**Economic**

In general, provide business cases and market analysis with potential funders and politicians as the target audiences. In particular, identify the following:

- If there are common themes between projects.
- How systems or components can be replicated via turnkey solutions or mass production. How systems can integrate with renewable energy generation and transport.
- How the use of hydrogen in an energy community can act as an economic alternative to energy infrastructure extension, upgrade, or redesign.
- How green tariffs, carbon credits, etc., change the business case.
- What the market pull/needs are for distributed and community hydrogen. What is missing at present.

**Environmental/technical**

How hydrogen systems can help to achieve the following:

- Make the most of renewable sources.
- Increase penetration of renewables.
- Reduce fossil fuel use.
- Improve community environmental footprint/reduce greenhouse gas (GHG) emissions.
- Identify technical gaps or the weakest links in overall systems (e.g., control systems, electrolyzers for dynamic loads, interfaces with renewable generation).
- Identify market needs that are not satisfied or only partially satisfied at present.
- Consult with industry on how technical gaps can be overcome and hydrogen systems can be integrated with low-carbon energy systems.
- What technologies are most suitable for different applications and at what size.
- Consult with industry on how mass production and modularization can occur using selected case studies as examples.
- What combinations of energy delivery networks should be used (e.g., electricity cables and/or hydrogen pipelines and/or gas pipelines). These could be posed as alternatives or to support existing energy networks.
- What improvements are needed to components / what opportunities are there for manufacturers (e.g., electrolyzers for renewables, H₂ sensors, control system improvements, efficiencies).
- Provide specifications of the barriers that need to be solved / opportunities for industry.

**Social**

How hydrogen systems help:

- Reduce energy poverty.
- Increase energy awareness.
- Improve health / reduce pollution.
- Create education/job opportunities.
- Improve energy security through diversification.
- Identify what are the social pull / needs for distributed and community hydrogen and what is missing at present.
Regulatory

The Task will endeavour to develop ongoing dialogue with governments and agencies to ensure regulation is a catalyst rather than an obstacle for the development of hydrogen technologies. It will identify where governments can facilitate the removal of barriers to development.

- Which bodies will be involved in integrating hydrogen systems into energy systems?
- What information/education do they require?
- How can hydrogen enhance community and economic development in a “doubly sustainable” manner (i.e., environmentally and economically)?

3.2 SWOT analysis

In order to grasp the current status of each project, a preliminary study was performed based on public and general information to identify its strengths, weaknesses, opportunities, and threats (SWOT). Success factors were then assigned to each S, W, O, and T. These success factors were divided into four categories:

- economic
- environmental/technical
- community (social)
- regulatory (policy, law, and regulation)

3.3 Software simulation

There are several software tools for modeling and simulation of hydrogen energy systems [1]. Representative tools are H2RES, HYDROGEMS, TRANSYS16, and HOMER. Hydrogen system evaluations performed in subtask B of Task 18 used HYDROGEMS [2], which is suitable for the detailed design and evaluation of system configurations and controls of hydrogen systems. However, much time and effort are required to create a simulation platform of an objective system. HOMER has the advantage of easy setup and fast execution, making it easy to construct platforms for different systems [3]. In addition, cost optimization is directly linked with operation simulation, and the result of the economic analysis is easy to address. However, HOMER is not suitable for detailed modeling or control strategies compared to HYDROGEMS. As a whole, HOMER is a good tool for screening and taking a general view of a hydrogen energy system. Because the major objective of this subtask is to conceptualize and review existing demonstration projects, HOMER was chosen as a simulation tool for the present study.

The currency used in each project was translated to USD ($) in HOMER. The exchange rates used in the economic analyses are based on the rate at 1 January 2015, as follows:

- EUR (€): $1 = €0.83 (€1 = $1.20)
3.4 Questionnaire

A questionnaire titled “Project Follow-Up Questions” was prepared and delivered to each project organizer in March 2014. The main purpose of this questionnaire was to obtain information in the community and regulatory aspects as shown in Figure 3.1 (work flow), though it also contained several questions related to the economic and environmental/technical aspects. The number of questions was limited to 20 in order to encourage response. The questionnaire is reproduced in Table 3.1.
Table 3.1. Project follow-up questionnaire for subtask 3.

<table>
<thead>
<tr>
<th>Project Follow-Up Questions</th>
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</thead>
<tbody>
<tr>
<td><strong>Economics</strong></td>
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<tr>
<td>4</td>
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<tr>
<td></td>
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<tr>
<td><strong>Environmental/Technical</strong></td>
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<tr>
<td>5</td>
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<td>6</td>
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<td>7</td>
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<tr>
<td>8</td>
</tr>
<tr>
<td><strong>Community</strong></td>
</tr>
<tr>
<td>9</td>
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<td>10</td>
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<tr>
<td>11</td>
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<td>12</td>
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<tr>
<td>13</td>
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<tr>
<td>14</td>
</tr>
<tr>
<td><strong>Regulatory: policy, law, and regulation</strong></td>
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<tr>
<td>15</td>
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<td>16</td>
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<tr>
<td>17</td>
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<td>18</td>
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<td>19</td>
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<tr>
<td>20</td>
</tr>
</tbody>
</table>
4 Outline of subject project

Areva (France) was the subtask 2.3 leader. Activity 2.3 dealt with the selection of the six projects that would be then used for the detailed analysis scheduled in subtask 3. The six projects were to be selected from the consolidated list produced in subtask 2.2 within the three identified categories of communities:

- island or rural application
- urban application
- industrial application

Out of these six projects, three generic models of the distributed and community H₂ concept would be developed so as to represent the three categories mentioned above. These concepts would be designed to be scaled up in light of concept replication and market penetration.

<table>
<thead>
<tr>
<th>#</th>
<th>Project name</th>
<th>Country</th>
<th>Location</th>
<th>Outline</th>
<th>System components</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Lolland residential CHP</td>
<td>Denmark</td>
<td>Vestenskov, Lolland</td>
<td>Small-scale residential combined heat and power (CHP) application with real community involved as well in a rural area</td>
<td>Wind turbine • Electrolyzer • Hydrogen pipeline • PEMFC (1.5 kW_{AC}) + Hot water tank</td>
</tr>
<tr>
<td>2</td>
<td>Myrte</td>
<td>France</td>
<td>Corsica island</td>
<td>Grid-connected renewable energy storage system with hydrogen in island</td>
<td>PV (560 kWp) • PEM Electrolyzer (110 kW) • H₂ and O₂ storage tank (35 bar, 126 kg_{H₂}) • PEMFC (160 kW)</td>
</tr>
<tr>
<td>3</td>
<td>Japanese residential CHP</td>
<td>Japan</td>
<td></td>
<td>Small-scale residential CHP application using energy grid in urban area</td>
<td>PEMFC (1 kW_{AC}) • Hot water tank</td>
</tr>
<tr>
<td>4</td>
<td>Octagon</td>
<td>USA</td>
<td>New York, NY</td>
<td>Large-scale CHP unit installation into an apartment building inside a city</td>
<td>PAFC (400 kW_{AC}) • Hot water supply system</td>
</tr>
<tr>
<td>5</td>
<td>FedEx Forklift</td>
<td>USA</td>
<td>Springfield, MO</td>
<td>Utilizing a number of forklifts powered by fuel cell in delivery center</td>
<td>FC-powered forklift ×40 • H₂ fueling system (NG reformed)</td>
</tr>
<tr>
<td>6</td>
<td>Hydrogen Office</td>
<td>UK</td>
<td>Methil, Scotland</td>
<td>Grid-connected renewable energy storage within a commercial building</td>
<td>Wind turbine (750 kW) • Alkaline Electrolyzer (30 kW) • H₂ storage tank (12 bar, 10 kg) • PEMFC (10 kW)</td>
</tr>
</tbody>
</table>
This report examines and documents each of the six selected projects in chapters 5 to 10. Each chapter first reviews an outline of the project, then introduces the system components and operation regime, including as much cost information as possible. A SWOT analysis is introduced as a preliminary analysis. Finally, a software analysis using HOMER is carried out using real data from each respective system to the extent possible. This would cover mainly the environmental/technical and economic aspects.
5 Lolland residential CHP

5.1 Background

Denmark is renowned for its large-scale installation of wind power. In addition, Denmark derives a large share of its electricity from cogeneration plants. The amount of CO\(_2\) emissions from power generation was reduced from 938 g/kWh in 1990 to 471 g/kWh in 2012 due to fuel switching, cogeneration, and wind power [4].

Over 50% of Denmark’s decentralized electric energy supply comes from cogeneration. Large-scale cogeneration systems are being adopted more rapidly than small-scale systems, since most of the cogeneration units are connected to district heating systems. Some 80% of the heat distributed via district heating networks comes from combined heat and power (CHP) plants. Because the Danish energy sector has already deployed medium- and large-scale CHPs, micro-scale CHP is attracting interest. For the gas distribution companies, an important business motivation is how to retain customers when heating demand decreases due to improved insulation and better appliance efficiency.

5.2 Outline

A large national research and demonstration project for fuel-cell technologies for micro cogeneration was launched in Lolland (Figure 5.1) in 2006. The formal title of the project is “Demonstration of Micro CHP Based on Danish Fuel Cells,” and in fact, the test field has not been limited to Lolland. The project consisted of three phases from 2006 to 2013 [5]. The summary of each phase outcome is as follows:

- In phase I (Nov. 2006 – Nov. 2007), micro combined heat and power (µCHP) prototypes were developed and tested at Danish Gas Technology Centre (DGC) as a third-party lab, and the results from these first tests provided valuable input for improvements on the next versions of the fuel cell–based CHP units [5].

![Figure 5.1. Location of Lolland in Denmark.](image)
In phase II (Nov. 2007 – Dec. 2011), nine fuel-cell–based μCHP systems were installed and demonstrated in residential houses.

In phase III (Jan. 2012 – 2013?), around 30 fuel-cell μCHP systems were installed and operated in two test fields.

In this project, the initial plan was to carry out field testing of μCHP units using three different types of fuel cell: low-temperature (LT) hydrogen--fueled proton exchange membrane fuel cells (PEMFC), high-temperature (HT) natural gas--fueled PEMFC, and natural gas--fueled solid oxide fuel cells (SOFC). During phase II, the HT-PEMFC track was replaced with a natural gas--fueled LT-PEMFC track because HT-PEMFC technology turned out to be immature for μCHP applications. The progress of field tests of SOFC is not published, and it might have stayed in the stage of stack improvement until the end of the project.

The project employed two different gas grid designs: one was an energy system based on a newly constructed hydrogen grid, and the other based on an existing natural gas grid [6]. In the hydrogen gas grid system (Figure 5.2), hydrogen is produced by an electrolyzer and stored in a tank (not illustrated in Figure 5.2). Hydrogen is delivered to each end user via the hydrogen grid. The basic concept of this system design is to use surplus wind power to produce the hydrogen, although the electrolyzer is connected to the electricity AC grid. In the case of the natural gas grid system utilizing the existing gas grid, hydrogen is locally produced at each site using a reformer. Thus, the main difference in the fuel cell units connected to these two grid types (the hydrogen or natural gas grid) is whether a fuel reformer is included as a system component or not.

A hydrogen grid system (electrolyzer, storage tank, and pipeline) was constructed in the town of Vestenskov in Lolland (Figure 5.3). The hydrogen was produced in two alkaline electrolyzers and fed to each house via the hydrogen grid. In Vestenskov, five μCHP units with LT-PEMFC were installed and tested in phase II, and 10 units
were installed and operated in phase III (as of December 2012). Two of these 10 units were operated for a full year, and one of these two was tested in continuous operation mode. Figure 5.4 shows the operation data from October 2011 until September 2012 for one selected site in Vestenskov. During this period, operating time reached 6500 hours, and the unit produced 6700 kWh of electricity and 8900 kWh of heat.

Figure 5.3. The electrolyzer container and hydrogen storage tank in Vestenskov [8].

Figure 5.4. Sample of operating hours of a hydrogen-fueled μCHP with LT-PEMFC from October 2011 until September 2012 [6,9]. (Each bar represents data accumulated over four weeks.)

The field test with a natural gas grid was carried out in Verde, where some 20 units in total were installed and tested. Test sites included both single-family houses and larger buildings such as schools. No heat storage tank was installed at any site. The accumulated operating time for these units exceeded 75,000 hours as of December 2012. However, the author is not aware of any published data for one full year of operation of the natural gas–fueled units.
As noted above, this project included some interesting options for small-scale CHP applications, though there is little data for long-term operation (over one year). Because the field test data for hydrogen-fueled μCHP with LT-PEMFC is available for one full year [6,9], this case study mainly covers the μCHP unit using a hydrogen-fueled system.

5.3 System components and operation

The current case study focused on the hydrogen-fueled μCHP application using LT-PEMFC, which was installed and tested in Vestenskov, Lolland. Because Lolland has abundant wind power, which occasionally exceeds local electricity demand, the basic concept of this system design was to use surplus wind power for hydrogen production and utilization. The wind turbines were connected to the grid, and all the power used for the electrolyzer was supplied from the grid. The system components examined here included an alkaline electrolyzer, hydrogen storage tank, hydrogen grid (pipeline), and μCHP unit using LT-PEMFC, as shown in Figure 5.5. The μCHP unit supplied heat and power simultaneously to each end user.

The features of each component are described below.

Figure 5.5. System configuration of hydrogen grid–based μCHP application.

Low-temperature proton exchange membrane fuel cell (LT-PEMFC)

The hydrogen-fueled μCHP units were developed and tested in both the laboratory and the field during phases I to III. The unit was based on a hydrogen-fueled LT-PEMFC (Figure 5.6) developed and supplied by a Danish company, IRD
By using pure hydrogen directly as fuel, the units had an excellent load response and fast start and stop. Each μCHP unit was comprised of a PEMFC and a 200-L hot-water tank for heat supply.

Specifications:

- stack gross power output: 1.66 kW_{DC}
- unit net power output: 1.50 kW_{AC}
- unit heat output: 1.50 kW
- gas supply pressure: 0.40 bar
- operating temperature: 67°C
- net electric efficiency (LHV): 47%
- thermal efficiency (LHV): 47%
- overall efficiency (LHV): 94%
- start-up time: 2 min
- standby power: 15 W_{AC}

Electrolyzer

A commercially available alkaline electrolyzer (not shown) was supplied by an Italian company. Two units of the electrolyzer were installed and operated for the field test. The main features of the electrolyzer were as follows:

- hydrogen (and oxygen) pressure: ≤ 8 bar(g)
- maximum H_{2} production: 20 Nm^3/hr
- maximum O_{2} production: 10 Nm^3/hr
- nominal H_{2} production: 16 Nm^3/hr
- nominal O_{2} production: 8 Nm^3/hr
- gas purity: 99.5 ± 0.1%
- max input power: 104 kW

The efficiency was suggested to be about 5.2 kW/Nm^{3} (= 104 kW / 20 Nm^{3}/hr at maximum operation), although the efficiency was not indicated.

Hydrogen tank

The hydrogen produced by the electrolyzer was stored in the hydrogen storage tank. The tank capacity was 25 Nm^{3} at 6 bar (g). The tank was located close to the container in which the electrolyzer unit was installed.

Hydrogen grid

The hydrogen grid was built in two phases. The grid piping for the first test houses was constructed of coated stainless steel, and the succeeding grid was made with PE (polyethylene) 80 tubing. The overall grid length was 500 m. Gas pressure in the grid was about 4 bar.
**Test field**

The village of Vestenskov was chosen for the field test of a hydrogen grid. The village has 540 inhabitants and about 150 single-family houses. Nine μCHPs using hydrogen-fueled LT-PEMFC were installed and in operation by the end of 2012. The existing heat generator acted as the backup and supplementary heater.

**Operation of the system**

Preliminary calculations showed that approximately 100% of the annual electricity demand in a standard Danish single-family house could be produced by a micro cogeneration unit in a thermal-following operation [6].

Field test data was collected and sent to DGC for continuous evaluation during the test. Two units in Vestenskov were operated for a full year. One of these two was tested in a continuous load-following mode, and the other was operated as a simulated smart-grid with four full thermal cycles a day. The current study focuses on the μCHP unit in load-following mode, which provided 86% of the house heat and hot water demand during the 2011–2012 heating season and 97% of the demand during the summer of 2012 [6].

### 5.4 SWOT analysis

Based on the case study of Task 18, which represents the project activity in 2005–2007 [5], SWOT analysis was performed on the Lolland CHP project. The outcomes of the analysis for the economic, environmental/technical, community/social, and regulatory aspects are shown in Tables 5.1, 5.2, 5.3, and 5.4, respectively.
**Table 5.1. SWOT analysis for Lolland CHP project — Economic aspect**

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diversification of energy source</td>
<td>High cost of the system</td>
<td>Suitable for large-scale market</td>
<td>Lack of general versatility in the world market</td>
</tr>
<tr>
<td>Reduction of system cost</td>
<td>Initial subsidies needed to shrink the Return on Investment (RoI) (from 14 to 5 years)</td>
<td>Multi-funding actions involved (JU funding for FC projects)</td>
<td>Increased running costs due to higher fuel costs</td>
</tr>
<tr>
<td>Synergy effect of energy infrastructure company and fuel cell supply company</td>
<td></td>
<td>Compatibility with current NG infrastructure supply</td>
<td>Difficulties linked to the internationalization of the market</td>
</tr>
<tr>
<td>Sufficiency of after support</td>
<td></td>
<td>Smart grid integration readiness</td>
<td>Maintenance cost</td>
</tr>
</tbody>
</table>

**Table 5.2. SWOT analysis for Lolland CHP project — Environmental/technical aspect.**

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>Improvement of system efficiency and reliability</td>
<td>Lack of renewables</td>
<td>Potential for hydrogen implementation to community/society</td>
<td>Technology immaturity for CHP application (SOFC, HT-PEMFC)</td>
</tr>
<tr>
<td>Huge on field testing bed for phase 3 of the project (upscale of the number of units employed)</td>
<td>Rigid specification of the system without considering user demand</td>
<td>Improvement of reliability of fuel cells</td>
<td>NG supply purity can affect performance of system (reformers/FCs)</td>
</tr>
<tr>
<td>CO₂ savings and high efficiency</td>
<td>LT-PEMFC: system optimization still to be improved (standby consumption of BOP, downtime)</td>
<td>Expansion of applications through addition of battery and RES</td>
<td>Not all 9 units achieved technical targets</td>
</tr>
<tr>
<td>LT-PEMFC got CE certification</td>
<td>HT-PEMFC (NG fuelled) not ready for field demo of µCHP even with higher quality fuel processing unit from Japanese CHP project (reformer and stack leak, system dormancy problems)</td>
<td>Good possibilities to improve performance to reach future phase targets</td>
<td></td>
</tr>
<tr>
<td></td>
<td>SOFC (NG fueled) failed CE certification in terms of CO₂ emission (passed the CE safety approval though)</td>
<td>SOFC-based systems have high potential for mass diffusion. Field testing was fundamental to improve system design</td>
<td></td>
</tr>
</tbody>
</table>
Table 5.3. SWOT analysis for Lolland CHP project — Community/social aspect.

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>Strong community involvement</td>
<td>High cost of the system</td>
<td>Dissemination of distributed power generation</td>
<td>Cost vs environmental benefit ratio</td>
</tr>
<tr>
<td>Received favorable reviews from the customers (sustainability and energy-minded people as well as promoted the concept among &quot;energy tourists&quot; and journalists)</td>
<td>Mechanical troubles during the first phase of the project</td>
<td>Increased public acceptance of energy saving</td>
<td>System optimization still needed to make the technology more acceptable to communities</td>
</tr>
<tr>
<td>Smooth installation</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Public contact with an advanced technology</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>diversification of applications: private households, smaller enterprises, and public buildings</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 5.4. SWOT analysis for Lolland CHP project — Regulatory aspect.

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>General availability of RCS</td>
<td>Need for unified RCS for authorities to act smoothly (1 year to get legal authorization to install the CHP in the households)</td>
<td>Reconsideration of RCS in reply to operation results</td>
<td>Inadequate and not well-defined regulations</td>
</tr>
<tr>
<td></td>
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<td></td>
</tr>
</tbody>
</table>

5.5 Software analysis

5.5.1 Inputs for software analysis

System configuration in HOMER
Based on the field test configuration of the hydrogen grid in Vestenskov (Figures 5.2 and 5.3), the virtual system configuration for simulation was set up in HOMER software as shown in Figure 5.7. It was composed of an electrolyzer, hydrogen tank, fuel cell, and backup boiler. In Figure 5.7, “electrical load” and “thermal load” designate the electric and thermal loads for one end user (residential house), respectively. Because of the lack of wind power information (wind condition, power output, cost, and share of grid), wind turbines were excluded from the simulation. In the simulation, the initial amount of hydrogen in the tank was assumed to be much larger than that of the real tank. The simulated tank was set up as having over 10 years’ worth of hydrogen for the site so that hydrogen could be regarded as an inexhaustible resource for the fuel cell operation in the model during the project period. HOMER requires a hydrogen-producing component (electrolyzer or reformer) and resource (power or fuel) for any hydrogen tank in its simulation. That is why they were added in the configuration, but neither the DC bus nor electrolyzer was used (they were “dummied” in the system configuration) in the simulation calculation.

The FC operation always followed the thermal load, and FC power was allotted to the electric demand preferentially. When the FC power exceeded the electrical load, the excess FC power was fed back to the grid. If the FC heat supply was insufficient for the thermal load, the shortfall of heat would be compensated by the backup boiler fueled by natural gas, which was assumed to be supplied via the existing natural gas grid.

![Figure 5.7. System configuration of Lolland CHP in HOMER.](image)

**Figure 5.7.** System configuration of Lolland CHP in HOMER.

**Electrical load**

In order to attain reliable simulation, the electrical and heat load data were carefully collected and prepared for the simulation. For the preliminary analysis the simulation used electrical load data provided by the project organizer (Danish Gas Technology Centre (DGC)) [12]. The data was obtained in the early 1990s, and includes electricity consumption profiles as 15-min averages from 25 single-family houses. Because the detailed data could not be obtained for the present study, the electricity profile presented in graphs in the literature (Figure 5.8) [12] was
manually converted to spreadsheets using image analyzing software.

Based on the information provided by the preliminary analysis [12], annual electricity consumption per house was assumed to be 5000 kWh. The author could find data for only February and July. Thus, the ratio of monthly consumption over one year was estimated based on the data published by the Danish Energy Agency [13], which represents data from all of Denmark. The monthly electric consumption was estimated based on the total value for the year (5000 kWh). An hourly profile was then fabricated for one house over a 24-hour period using data from 25 randomly selected houses (15 min data), and the accumulated amount for each month using the daily profile was adjusted so as to agree with the monthly amount calculated by the above procedure.

The information from the above procedure was then used to calculate the hourly electrical load profile of one single-family residential house for one year (8760 hours). The features of the electrical load data are summarized in Figure 5.9.

![Figure 5.8. Electricity load profile examples for 25 houses, weekday in February (15 min average) [12].](image-url)
Thermal load

As mentioned above, in phases II to III, several units of the hydrogen-fueled μCHPs were installed and operated at a number of residential houses in Vestenskov, Lolland. One unit among them was tested under a continuous load-following mode for at least one year, and the operation data was collected and sent to DGC continuously [6]. Figure 5.10 shows the observed data for thermal energy supplied to the house in question from October 2011 to September 2012. The monthly thermal load can be estimated from this graph. However, it includes some storage data during the winter. For example, the data for 08/2012, which encompasses February (weeks 5 to 8 of 2012), was unaccountably low. Therefore, the thermal data was partially revised by referencing other data. As was the case with electrical load, yearly total thermal demand per house was assumed based on the preliminary analysis presented by DGC [12], which was 17,000 kWh. The thermal demand of each month was then based on that total for the year. No reference data could be obtained for an hourly (or minutely) profile of the thermal load in the Danish houses. In addition, because every hydrogen-fueled μCHP was equipped with a hot-water storage tank, it was not necessary for the heat supply to directly follow the real thermal load. In this study, using the Japanese residential CHP study (Chap. 7) as the template, the hourly distribution of thermal demand was assumed as listed in Table 5.5. Based on the above information and procedure, the hourly thermal load profile of one single-family residential house was created for one year (8760 h). The features of the thermal load data are summarized in Figure 5.11.
Figure 5.10. Thermal energy supplied by hydrogen-fueled μCHP to a single-family house [6,9].

Table 5.5. Hourly distribution of thermal load over one day. Summer: June–Aug., Winter: Nov.–Mar. Shoulder: others.

<table>
<thead>
<tr>
<th>Time</th>
<th>Hot water load (%)</th>
<th>Summer</th>
<th>Winter</th>
<th>Shoulder</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>0.00</td>
<td>1.70</td>
<td>3.00</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>0.00</td>
<td>1.00</td>
<td>1.50</td>
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<tr>
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<td>0.00</td>
<td>1.00</td>
<td>1.50</td>
<td></td>
</tr>
<tr>
<td>3</td>
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<tr>
<td>8</td>
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<tr>
<td>9</td>
<td>0.00</td>
<td>3.50</td>
<td>2.70</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>0.00</td>
<td>2.90</td>
<td>2.00</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>0.00</td>
<td>2.60</td>
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<tr>
<td>12</td>
<td>3.20</td>
<td>2.10</td>
<td>1.50</td>
<td></td>
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<tr>
<td>13</td>
<td>3.30</td>
<td>2.10</td>
<td>1.50</td>
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<tr>
<td>14</td>
<td>3.30</td>
<td>1.80</td>
<td>1.50</td>
<td></td>
</tr>
<tr>
<td>15</td>
<td>5.50</td>
<td>3.60</td>
<td>3.40</td>
<td></td>
</tr>
<tr>
<td>16</td>
<td>8.50</td>
<td>7.20</td>
<td>9.50</td>
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<td>17</td>
<td>11.00</td>
<td>8.50</td>
<td>10.20</td>
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<td>18</td>
<td>14.00</td>
<td>11.80</td>
<td>12.20</td>
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<td>19</td>
<td>13.80</td>
<td>12.10</td>
<td>12.40</td>
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<td>20</td>
<td>13.70</td>
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<tr>
<td>21</td>
<td>13.80</td>
<td>8.00</td>
<td>8.50</td>
<td></td>
</tr>
<tr>
<td>22</td>
<td>6.80</td>
<td>5.60</td>
<td>4.60</td>
<td></td>
</tr>
<tr>
<td>Sum</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td></td>
</tr>
</tbody>
</table>
Assumed performance of PEMFC

In the hydrogen-fueled μCHP unit, the performance of LT-PEMFC is one of the key parameters. As depicted in Section 5.3, at the PEMFC’s rated operation (1.5 kW_{AC}) the electrical and thermal efficiencies were both 47%, and thus the overall efficiency was 94%. In the current analysis, these values were used for each constant efficiency regardless of current density. Because the hydrogen-fueled PEMFC demonstrated excellent quick start and load change response [6] and the time-step of the present simulation was one hour, the lag of power generation after a load change was not considered. The efficiency of the natural gas–fueled backup boiler was set as 80%, and the lag of heat supply after a load change was not considered either.

Assumed cost

Thanks to Mr. Jan de Wit (DGC), the author was able to obtain some important cost information related to the project via personal communication. Since the main purpose of the Lolland CHP project was to demonstrate the application of μCHP at a small-demand site, the components of the hydrogen grid (electrolyzer, H₂ tank, and pipeline) were newly constructed/installed in Vestenskov. The total cost of the new hydrogen grid was about €1.2 million (ca. $1.4 million). If the hydrogen delivery cost was calculated to include this installation cost, it would be over $200/kg H₂. Because an economic analysis incorporating this hydrogen cost cannot produce any useful results, in the present analysis the hydrogen delivery cost was set arbitrarily by controlling the capital cost of the hydrogen tank.

According to Mr. de Wit, the LT-PEMFC-based hydrogen-fueled μCHP unit developed by IRD [11] was not
fully commercialized at that time, and the capital cost dropped by about 50% over the course of this project. The unit cost as of January 2014 was about €18,000, excluding the installation cost. Based on that, the total installation cost of the hydrogen-fueled µCHP unit is assumed to be €20,000 ($24,000) in the present analysis. Operating and maintenance costs were not considered.

The grid costs of electricity and natural gas were also determined by the inputs from Mr. de Wit. In Denmark, private and small customers use the electricity produced by mini or micro CHP plants, which is the most feasible arrangement. In that case, the electricity cost was around €0.3/kWh ($0.36/kWh) including tax. If the customer wanted to sell the electricity back to the grid, he would only receive a low spot price, probably have to pay a charge for feed-in, and therefore likely end up getting nothing for the sale. The sale of electricity from a µCHP therefore was not of interest in the project, and no profit from the sale of electricity was considered in the present analysis. The grid price of natural gas was assumed as €1.2/Nm$^3$ ($1.44/Nm$^3$) based on the input from Mr. de Wit. No capital cost was considered for the backup boiler, electrolyzer, and DC bus.

Assumed costs in the present analysis are summarized as follows:

- µCHP unit with LT-PEMFC (1.5 kW$_{AC}$): Capital: $24,000 (€20,000), O&M: $0
- electric power: purchase price: $0.36 kWh (€0.3/kWh), sale price: $0/kWh
- gas price: $1.44/Nm$^3$ ($1.20/Nm^3$)
- H$_2$ delivery cost: $5/kg (€4.17/kg)

Scope of the analysis

In the present simulation, µCHP (FC) operation always followed the thermal load, and the excess electric power was fed back to the grid. The shortfall of the thermal load was compensated for by the backup boiler. The capacity of the hydrogen tank was virtually set as significantly large, 6000 kg. Therefore, the electrolyzer did not need to operate through the entire simulation.

From the environmental/technical point of view, the present analysis focused on the minimum load ratio of the FC, because it was expected that a hydrogen-fueled PEMFC would show an excellent start-up response. The minimum load ratio could be set at a lower value than that of a natural gas–fueled PEMFC. In particular, the present analysis investigated the effect of the minimum load ratio on the operation time, the share of FC output, and the reduction of CO$_2$ emissions.

From the economical point of view, the main parameters were the capital cost of the µCHP unit (including installation), the hydrogen delivery cost, and the power price. The analysis was able to specify the conditions for economic feasibility of the µCHP installation versus existing energy facilities.

Time-step and lifetime of the simulation were set as one hour (60 min) and 10 years, respectively. The lifetime of all the system components was assumed to be the project lifetime (10 years), and the interest rate was fixed at 0 %.

5.5.2 Outputs from software analysis
Environmental/technical

In the present simulation, the μCHP (FC) operation always followed the thermal load preferentially. When we consider the effect of the minimum load ratio on μCHP operation, thermal load is critical. The thermal energy output at rated operation was 1.5 kW, the same as the electrical power output. For example, if the minimum load ratio was set at 30%, the μCHP would operate whenever the thermal load was over 0.45 kW. The main output parameters of the μCHP operation are listed in Table 5.6. The operation time and the μCHP share of demand are plotted versus the minimum load ratio in Figures 5.12 and 5.13, respectively. As expected, both operation time and share of μCHP are inversely related to minimum load. Under the presently assumed demand of a residential house, the thermal demand (17,000 kWh/yr) was significantly higher than the electrical demand (5,000 kWh/yr). In addition, excess power produced by the μCHP could be fed back to the grid. Therefore, the share of μCHP output of electrical demand was in the range of 70 to 83%, much higher than the share of thermal demand (46–56%). Because the hydrogen was assumed to be produced using renewable energy (wind turbines) and no CO₂ emissions were considered for hydrogen production and delivery, the reduction of CO₂ emissions by the μCHP installation was large, as shown in Figure 5.14. The reduction rate would be over 50%, even when the minimum load ratio was 50%. This highly effective CO₂ reduction is one of most attractive features of this hydrogen-fueled μCHP application.

Table 5.6. Results of simulated μCHP operation over one year.

<table>
<thead>
<tr>
<th>FC minimum operation ratio</th>
<th>FC operation time per year</th>
<th>Total electric power</th>
<th>Electrical Production</th>
<th>Electrical Consumption</th>
<th>Total thermal energy</th>
<th>Thermal production</th>
<th>Thermal Consumption</th>
<th>Electrical share of FC in demand</th>
<th>Thermal share of FC in demand</th>
<th>%</th>
<th>hrs</th>
<th>kWh/yr</th>
<th>kWh/yr</th>
<th>kWh/yr</th>
<th>kWh/yr</th>
<th>kWh/yr</th>
<th>kWh/yr</th>
<th>kWh/yr</th>
<th>kWh/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>0%</td>
<td>8.208</td>
<td>9.903</td>
<td>9.214</td>
<td>686</td>
<td>5,001</td>
<td>4,899</td>
<td>17,009</td>
<td>9,238</td>
<td>7,770</td>
<td>86.3</td>
<td>54.3</td>
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</tr>
<tr>
<td>10%</td>
<td>8.146</td>
<td>9.932</td>
<td>9.277</td>
<td>682</td>
<td>5,001</td>
<td>4,896</td>
<td>17,009</td>
<td>9,232</td>
<td>7,777</td>
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<tr>
<td>20%</td>
<td>7.992</td>
<td>9.888</td>
<td>9.174</td>
<td>722</td>
<td>5,001</td>
<td>4,865</td>
<td>17,009</td>
<td>9,199</td>
<td>7,810</td>
<td>85.8</td>
<td>54.1</td>
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<td></td>
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<tr>
<td>30%</td>
<td>7.320</td>
<td>9.834</td>
<td>8.924</td>
<td>910</td>
<td>5,001</td>
<td>4,834</td>
<td>17,009</td>
<td>8,948</td>
<td>8,060</td>
<td>81.8</td>
<td>52.6</td>
<td></td>
<td></td>
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<td></td>
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<tr>
<td>40%</td>
<td>7.076</td>
<td>9.791</td>
<td>8.803</td>
<td>988</td>
<td>5,001</td>
<td>4,790</td>
<td>17,009</td>
<td>8,827</td>
<td>8,182</td>
<td>80.2</td>
<td>51.9</td>
<td></td>
<td></td>
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<tr>
<td>50%</td>
<td>6.366</td>
<td>9.542</td>
<td>8.314</td>
<td>1,229</td>
<td>5,001</td>
<td>4,542</td>
<td>17,009</td>
<td>8,336</td>
<td>8,673</td>
<td>75.4</td>
<td>49.0</td>
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</tbody>
</table>

Figure 5.12. Yearly operation time of CHP vs. minimum load ratio.

Figure 5.13. Yearly share of CHP output vs. minimum load ratio.
The monthly shares of the μCHP output were examined in order to obtain a detailed description of the effect of the minimum load ratio. Figure 5.15 illustrates the monthly energy consumption and the share of electrical and thermal demand met by the μCHP. Figure 5.16 shows the monthly share profiles for two values of the minimum load ratio. In winter, when thermal demand was high, the share of electrical demand was quite high at over 90%, while the share of thermal demand was around 50–60%. In summer, because thermal demand was very low, the μCHP output dropped. In that season, the share of thermal demand was over 70%, but the share of electrical demand decreased to 50–60%, since the decrease of electric demand in summer was small compared to that of thermal demand. The heat output of the μCHP at rated operation was 1.5 kW, and thus the minimum load was 0.15 kW and 0.45 kW when the minimum load ratio was 10% and 30%, respectively. Monthly average profile of thermal load presented in Figure 5.11 implies that thermal load remained between these two minimum loads for long periods during the daytime from July to October. Therefore, the effect of the minimum load ratio was remarkably clear in that season. Considering these results, shutting down the μCHP in summertime is one option to achieve efficient operation and longer life, because frequent start and stop operation would increase idle time and rapidly degrade the cell/stack components of fuel cells. Conversely, the technical target for improving the μCHP should be to achieve efficient operation under lower demand.

The observed thermal share presented in Figure 5.10 seems to be higher than the calculated results. However, a detailed comparison between them could not be performed, because the load data from the actual site was not clear.
Figure 5.15. Simulated operation results of μCHP when rated power of FC was 1.5 kW<sub>AC</sub>.

Figure 5.16. Calculated monthly share of μCHP output by demand.
Economic

To investigate the effect of various costs on the economic feasibility of the μCHP system, a sensitivity analysis was carried out using HOMER software. In the present analysis, the author has focused on the μCHP (FC) capital cost, price of grid power, and H$_2$ delivery cost. It must be noted that the μCHP (FC) capital cost and grid power cost were almost at the level of real prices at the time of the project. However, as noted above, the H$_2$ delivery cost assumed here was much lower than the real cost, which would include the costs of the electrolyzer, hydrogen tank, and pipeline construction.

Figure 5.17 shows the optimal system map as functions of the μCHP (FC) capital and H$_2$ delivery costs. When the μCHP (FC) capital multiplier was 1, the cost was $24,000, and when the H$_2$ delivery cost multiplier was 1, the cost was $5/kg. This indicates that economic feasibility cannot be realized at the present capital cost ($24,000, multiplier = 1), even when the H$_2$ delivery cost is lower than $2/kg (multiplier = 0.4). It also indicates that the H$_2$ delivery cost should be lower than $3/kg (multiplier = 0.6) when μCHP (FC) capital cost is assumed at $14,400 (multiplier = 0.6) in order to achieve economic feasibility under the current power price ($0.36 = €0.30/kWh).

Figure 5.18 shows the optimal system map as functions of the grid power price and H$_2$ delivery cost. For this analysis, μCHP (FC) capital cost was assumed as $18,000 (multiplier = 0.75) because it can be expected to be realized in the near future. This figure indicates that the region where μCHP (FC) is economically feasible would be expanded by the increase of the power price. If the power price was over $0.6/kWh, the required cost of H$_2$ delivery would be lower at $4/kg (multiplier = 0.8).

![Figure 5.17. Optimal system map when CHP output was 1.5 kW$_{AC}$, minimum load ratio was 20%, and grid power price was $0.36/kWh.](image-url)
Figure 5.18. Optimal system map when CHP output was 1.5 kW<sub>AC</sub>, minimum load ratio was 20%, and CHP capital cost was $18,000 (multiplier = 0.75).

5.6 Summary

A residential μCHP system was installed and demonstrated in a rural community in Lolland, Denmark. About 15 hydrogen-fueled μCHP systems using LT-PEFC were installed at the field site, where hydrogen was produced by electrolyzers using a renewable energy source (wind power) and supplied to each residential house via underground pipeline. The project has attracted the attention of many people. The concept of simultaneously achieving both the consumption of surplus wind power in the region and the reduction of CO<sub>2</sub> emissions from residential sites by using hydrogen in residences is very attractive and instructive.

In this project, hydrogen was produced by electrolyzers powered by RES (wind turbine). The nominal performance of the μCHP system was already sufficient, although the installation cost was still high. According to the simulation, because of high demand for thermal energy and the capability of reverse power flow to the grid, the operating hours of the μCHP were very long at over 7000 hours per year. In addition, CO<sub>2</sub> emissions would be reduced by over 50% with the μCHP installation, a great benefit for a rural community.

Reducing the hydrogen delivery price is not easy, but it is an issue that must be addressed if economic feasibility is to be realized. The results of our simulation in regard to the economic feasibility of this hydrogen-fueled μCHP system indicated that the H<sub>2</sub> delivery cost should be lower than $3/kg, when the μCHP (FC) capital cost is assumed as $14,400 under the current power price ($0.36 = €0.30/kWh). Because the μCHP is fueled by pure hydrogen, efficient use of hydrogen is important. Thus, the minimum load ratio of μCHP operation should be kept low as much as possible. Considering the trade-off between capacity factor and durability of the system, the scale and operation strategy should be carefully designed. Because a hydrogen pipeline in a rural area must be long, we need to consider a more cost-effective option for hydrogen delivery.
6. Myrte

6.1 Background [14]

Island communities have a unique motivation to meet their power demand while reducing their dependence on fossil fuels. Because islands typically depend on fossil fuels for their energy, the carbon footprint of their power generation is higher than that on the mainland. In addition, the high level of imported fossil fuels poses social and economic risks, such as sensitivity to severe weather, risks to the development of tourism, and sensitivity to the volatile costs of imported materials.

The introduction of renewable energy sources faces problems related to imbalances between generation and demand. Examples of this imbalance include intermittency with wind power, difficulty in regulating or controlling production with geothermal, lack of coincidence between peak production and peak load with solar, and still to be achieved economic viability with marine energy. In addition, the upper limit of renewable installations added to the island grid must be lower than that of a large-scale grid on the mainland. Above a certain threshold, the network manager is unable to manage the instability generated by intermittent renewables. The main functions of energy storage are load leveling to smooth the RES power output, time shifting to store electricity during low-demand periods and feeding into the grid when demand and/or electricity prices are high, and grid stabilization by acting as secondary and tertiary reserves for grid frequency and voltage regulation [15]. Therefore, energy storage is both a solution to real problems and an opportunity for the sustainable development of islands. However, not all technologies meet the particular needs of island communities.

Hydrogen is a unique storage medium for the unstable renewable energy sources on islands in that it offers many advantages for the storage of the RES output, in particular [15]:

- Water electrolysis is suitable for hydrogen production using the high dynamics of RES (e.g., wind and photovoltaic).
- Produced hydrogen can be stored and used to produce electricity in fuel cells.
- Carbon-free electricity production without generating toxic compounds.
- Noise-free.
- High efficiency when combined with power and heat production.
- No self-discharge over time.
- Independent optimization of the system-delivered power (fuel cell power: kW) and of the available stored energy (gas storage: kWh).

It can be suggested that energy storage systems using hydrogen can meet the particular needs and preserve the fragile environment of island communities.

6.2 Outline of the Myrte platform [15]

MYRTE (Mission hYdrogen – Renewable for the inTegration on the Electrical grid) is a project that involves a
A hybrid system of a grid-connected photovoltaic plant and a hydrogen energy storage unit. The Myrte platform [16] is one of the PEPITE (Study and experimentation of intermittent energy management using electrochemical technologies) project applications included in the PAN-H (national action plan on hydrogen and fuel cells) program of the ANR (French national research agency), under the reference ANR-07-PANH-012. This platform comes from a partnership between the University of Corsica in Vignola (Ajaccio, Corsica, France; Figure 6.1), Areva, and the CEA (Atomic energy and alternative energies commission; a French government-funded technology research organization).

The objective of the project is to test full-scale coupling of a PV power plant to a hydrogen energy storage system. Combining the PV power plant with hydrogen, Myrte adds value to a plentiful local resource—sunlight—and solves the constraint of intermittence related to the injection of fluctuating renewable energy in the relatively weak island grid.

Corsica is a relatively big island in the Mediterranean Sea, with a population of around 300,000 (Figure 6.1). Because Corsica is also a famous tourist destination, the Myrte project had to be developed with awareness of both social acceptance and protection of the environment (landscape and wildlife). The contract was concluded and the Myrte project was kicked off in September 2009.

The key figures of the project are listed in Table 6.1. In phase I installation, PV installation (including civil engineering) cost was €2.4 million (ca. $2.88 million). Because the Myrte project was developed with awareness of both social acceptance and protection of the environment, the system components (e.g., gas storage tanks) were placed partially below grade so as not to be visible from the foot of the hill (Figure 6.2). An emergency access road was also constructed for firefighters. The cost for land preparations was €2.1 million (ca. $2.52 million).
The Myrte platform has to fulfill two main applications [15]:

- Daily peak load shaving of the electrical demand of the Corsican electrical grid by using a photovoltaic (PV)/hydrogen system renewable energy system.
- Use of hydrogen for the PV production smoothing to prevent strong variations in the load.

**Table 6.1. Key figures of Myrte project [18].**

<table>
<thead>
<tr>
<th>Project leader</th>
<th>University of Corsica</th>
</tr>
</thead>
<tbody>
<tr>
<td>Duration</td>
<td>6 years, 2010–2015</td>
</tr>
<tr>
<td>Cost</td>
<td>€21 million</td>
</tr>
<tr>
<td>Phase I installation</td>
<td>€12.4 million</td>
</tr>
<tr>
<td>Phase II installation</td>
<td>€5.9 million</td>
</tr>
<tr>
<td>Operations</td>
<td>€2.7 million</td>
</tr>
<tr>
<td>Funding</td>
<td>€21 million</td>
</tr>
<tr>
<td>EU</td>
<td>€7.4 million</td>
</tr>
<tr>
<td>CT Corsica</td>
<td>€4.6 million</td>
</tr>
<tr>
<td>French State</td>
<td>€3.0 million</td>
</tr>
<tr>
<td>Partners</td>
<td>€6.0 million</td>
</tr>
</tbody>
</table>

**6.3 System components and operation**

Figure 6.3 illustrates the system configuration of the entire platform. The platform is composed of several subsystems, including[15]:

- a photovoltaic farm that aims to provide electrical energy to the grid and to the electrolyzer
- an electrolyzer that generates gaseous hydrogen (H₂) and oxygen (O₂) using the surplus electricity
• an H₂/O₂ fuel cell that produces electricity for delivery to the grid using the gas stored in the reservoirs
• storage capacity for water produced by the fuel cell and provided from the water network
• a heat management system that ensures the storage and management of the heat produced by the system
• electricity management that ensures the conditioning of the electrical energy provided to the grid

**Figure 6.3.** System configuration of the Myrte platform.

The features of the components installed in each phase are as follows:

**Phase I (2009–2011) installation**
• photovoltaic generator: 560 kWp
• PEM electrolyzer: 50 kW, 10 Nm³/h-35 barg
• H₂ storage tank: 28 m³@35 barg × 2 – 1400 Nm³·H₂
• O₂ storage tank: 28 m³@35 barg × 1 – 700 Nm³·O₂
• PEM fuel cell: 100 kW

**Phases II and III (2012–) installation (Greenergy Box™)**
- PEM electrolyzer: 50–60 kW, 13 Nm³/h-35 barg
- PEM fuel cell: 60 kW

As of May 2014, the overall system configuration is:
- photovoltaic generator: 560 kWp
- PEM electrolyzer: 110 kW, 25 Nm³/h-35 barg
- H₂ storage tank: 28 m³@35 barg × 2 – 1400 Nm³ₕ₂
- O₂ storage tank: 28 m³@35 barg × 1 – 700 Nm³ₒ₂
- PEM fuel cell: 160 kW

The features of each component are described below. [16]

**AC grid**
The peak electrical demand is about 500 MW (in winter). The grid connects to the mainland of Italy via Sardinia (Sardegna) island, and the capacity of this connection is about 150 MW. There are several fossil-fuel (oil/diesel) power plants producing total power of 322 MW. There are also plenty of renewable energy sources on the island, such as hydro power (160 MW), wind power (18 MW), PV (67 MW), and a biogas power plant (7 MW).

**Photovoltaic generator**
The 560-kWp photovoltaic array is composed of 2240 tilted (30°) photovoltaic modules (TENESOL, TE2200: 245 Wc). The PV plant was installed in phase I (June 2011). The active surface used for modules is 3700 m².

**DC/AC converter**
There are 28 DC/AC electric inverters (SMA SUNNY TRIPOWER 17000TL). Each inverter has two power inputs with a total power equal to 17 kW. Electric inverters are piloted by the command control, which can reduce the supplied power injected into the electrical grid using the programming interface of each inverter (degradation of the PV production). For that purpose inverters modify the cos (φ) connecting the various powers (active, reactive, and visible). The power output can be reduced by selecting the number of electric inverter inputs used.

**Proton exchange membrane electrolyzer (PEM electrolyzer)**
The electrolyzer was developed and supplied by Areva [19]. The first PEM electrolyzer unit, delivered in phase I (May 2011), has a hydrogen production capacity of 10 Nm³/h, and requires net AC power of about 50 kW. This unit is composed of one stack of 60 cells, and the active area of each cell is 290 cm². The AC/DC converter associated with the electrolyzer is included in this subsystem. The standard operating temperature and pressure of the electrolyzer are respectively 50°C and 35 bar. The minimum load ratio and the parasitic energy consumption of the associated auxiliaries are low, 10% and 5% of the electrolyzer’s nominal power, respectively.
A second PEMFC unit included in Greenergy Box was installed in May 2014. The features of this second unit are described in the section on Greenergy Box.

Proton exchange membrane fuel cell (PEMFC)
The PEMFC unit was also developed and supplied by Areva. The first PEMFC unit, installed in phase I (May 2011), has a net power output of 100 kW\textsubscript{AC}. The DC/AC converter associated with the fuel cells is included in this subsystem. This unit is composed of four stacks of 100 cells, and the active area of each cell is 400 cm\textsuperscript{2}. The operating temperature of the FC is 70°C, and the FC stacks are cooled by circulating coolant. Hydrogen is supplied at low pressure (~1.5 bar) and used gas is recirculated; hence, the hydrogen utilization factor is almost 100%. Oxygen is supplied to the cathode as an oxidant. Applying oxygen to the cell operation provides positive effects on the system setup and performance compared to typical air feeding, such as high stack efficiency, simplifying the balance of plant (BOP) (no blower, no filter, no humidifier), wide power range with similar efficiency, and faster dynamics (start and stop transient). The minimum load ratio and the parasitic energy consumption of the associated auxiliaries are low at 10% and 5% of the fuel cell’s nominal power, respectively.

A second PEMFC unit included in Greenergy Box was installed in May 2014. The features of this second unit are described in the section on Greenergy Box.

Gas storage tank
Two H\textsubscript{2} tanks (35 bars) and one O\textsubscript{2} tank (35 bars) were built by GLI ETS Citergaz (Figure 6.4). These tanks have an individual capacity of 28 m\textsuperscript{3}, and their pressure is limited to 40 bars. The net electrical energy stored is equivalent to 1.75 MWh. The water tank has a capacity of 400 L and is integrated into the fuel cell’s subsystem. The H\textsubscript{2} tank pressure can oscillate between a minimum and a maximum, amounting to H\textsubscript{2} quantities between 200 and 1400 Nm\textsuperscript{3}.

![Figure 6.4. Storage tanks for hydrogen and oxygen gas.](image)

Greenergy Box
Based on the operation experience with the first installed unit of the PEMFC and the PEM electrolyzer, Areva
developed an advanced energy storage and management system, Greenergy Box, which is a box containing a PEMFC unit, a PEM electrolyzer unit, and an electrical control system [20] (Figure 6.5). The Greenergy Box was installed at Myrte in May 2014 and is undergoing field testing. In the Greenergy Box, both the PEMFC and the PEM electrolyzer are more compact than the first units, and the individual electrical rectifier (AC/DC converter) for each unit was unitized.

![Prototype Greenergy Box installed at the Myrte site.](image)

Figure 6.5. The prototype Greenergy Box installed at the Myrte site.

The PEM electrolyzer unit has a hydrogen production capacity of 13 Nm$^3$/h, which requires a net AC power of about 50–60 kW. The stack configurations are the same as the first unit (a single stack of 60 cells), and the active area of each cell is 290 cm$^2$. The improved cell performance has increased the hydrogen production rate to 13 Nm$^3$/h from the 10 Nm$^3$/h of the first unit.

The PEMFC unit included in the Greenergy Box has a net power output of 60 kW$_{AC}$. This unit is composed of four stacks of 100 cells, and the active area of each cell is 130 cm$^2$.

**Thermal management system**

The Myrte system includes a thermal management system with a capacity of 800 kWh/day (not illustrated in Figure 6.3). The thermal tanks are made for 1/3 by phase change materials (latent thermal) and for 2/3 by water (sensitive thermal). This thermal energy will be used for the air-conditioning of the building indoor environment. This cogeneration will increase the overall efficiency of the system.

**Operation of the system**

As noted above, the main aim of the Myrte is daily peak load shaving of the AC grid. As shown in Figure 6.6, the daily operation regime has been planned as follows: during sunny hours, the electrolyzer is powered only by PV output via the AC grid, and hydrogen and oxygen are produced and stored. During the highest load hours in late afternoon, the fuel cell is turned on and its power is fed back to the grid. Typical operation time of the FC is from 18:00 to 20:00 (two hours) in a day. Therefore, the role of the Myrte is not only peak shaving but also peak shift and leveling the grid load. On the other hand,
the regime of thermal energy utilization is not clear at present.

6.4 SWOT analysis

A SWOT analysis was performed on the Myrte project based on public information [14,15,16,19,18]. The outcome of the analysis for each aspect of economic, environmental/technical, community/social, and regulatory is shown in Tables 6.2, 6.3, 6.4, and 6.5, respectively.
Table 6.2. SWOT analysis for Myrte project — Economic aspect.

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diversification of energy source: PV/RES</td>
<td>High cost of the system</td>
<td>Suitable for large-scale market</td>
<td>Lack of general versatility in the world market</td>
</tr>
<tr>
<td>Reduction of the island energy dependence on expensive fossil fuels imports</td>
<td>Subsidies needed to finance the project. No RoI at that time (demonstration)</td>
<td>Cost reduction due to normalization</td>
<td>Difficulties linked to the internationalization of the market</td>
</tr>
<tr>
<td>High energy production due to high PV production</td>
<td></td>
<td>Synergy with smart grids investments</td>
<td>Maintenance cost</td>
</tr>
<tr>
<td>Greenergy Box (integration of FC and electrolyzer in one component) is a source of cost reduction</td>
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</table>

Table 6.3. SWOT analysis for Myrte project — Environmental/technical aspect.

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂-free, no contaminants</td>
<td>Low efficiency if no CHP</td>
<td>Potential for hydrogen implementation to community/society</td>
<td>FC stacks operating mode difficult to tune (with H₂ &amp; O₂ recirculation)</td>
</tr>
<tr>
<td>Greenergy Box certification to be obtained</td>
<td>Durability of components to be improved and confirmed</td>
<td>Improvement of reliability of fuel cells</td>
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</tr>
<tr>
<td>High efficiency with LT CHP</td>
<td></td>
<td>Expansion of applications through addition of metal hydrides for H₂ storage</td>
<td></td>
</tr>
<tr>
<td>Controls of the plant running efficiently</td>
<td></td>
<td>Demonstration of integrated system (Greenergy Box)</td>
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</tbody>
</table>
Table 6.4. SWOT analysis for Myrte project — Community aspect.

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>Strong local political involvement</td>
<td>Hydrogen still seen as a bit mysterious and dangerous (not on island, but more on mainland France)</td>
<td>Diversification of energy applications</td>
<td>Safety authorities still cautious about hydrogen</td>
</tr>
<tr>
<td>Strong media communication throughout France &amp; Europe</td>
<td></td>
<td>Corsica island can be a visible H₂ showcase for other islands</td>
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</tr>
<tr>
<td>Local (island) people very favorable toward this installation</td>
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<td></td>
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<tr>
<td>Many site visits on site organized by the local partner (University)</td>
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</table>

Table 6.5. SWOT analysis for Myrte project — Regulatory aspect.

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>Myrte is a strong demonstration of state-of-the-art safety studies and H₂ studies</td>
<td>Need for new H₂ energy regulations - H₂ building is still under discussion with authorities (non-blocking though)</td>
<td>Exemplary project that could be used as state-of-the-art for new regulations</td>
<td>Safety authorities still cautious about hydrogen</td>
</tr>
<tr>
<td>The installation, very well publicized, should help to spread H₂ knowledge and help regulators</td>
<td>HELION is working in normalization and standards group (at ministry levels) and Myrte could serve new regulations</td>
<td></td>
<td>Still a lack of clear regulation - particularly on decentralized hydrogen production via electrolysis</td>
</tr>
</tbody>
</table>

6.5 Software analysis

6.5.1 Inputs for software analysis

System configuration in HOMER

Figure 6.7 shows the system configuration of the Myrte in HOMER software. In the real system of the Myrte, all the power is going to and coming from the AC grid. In particular, the power source of the electrolyzer is the PV power only, although the power is supplied via the AC grid. In the present HOMER simulation, in order to assure that the PV power would be supplied to hydrogen production in preference to feeding back to the grid, the electrolyzer was connected to the virtual DC bus. Thus, when the PV output exceeded the minimum load ratio of the electrolyzer, the PV output would be supplied to the electrolyzer preferentially and surplus power would be fed to the grid.
Because the HOMER needs a specific load for the simulation and there is no specific load in the Myrte site, in the present simulation a dummy load was installed in the system as Primary Load 1; however, this had no influence on the system analysis.

The improvement of PEMFC performance due to oxygen utilization was taken into consideration in the analysis, although an oxygen tank was not included in the HOMER platform.

![Figure 6.7. System configuration of Myrte in HOMER.](image)

**Solar radiation**

Solar radiation data observed at the Myrte site in 2013 was provided by Prof. Philippe Poggi, University of Corsica. The data was acquired every 10 min. Figure 6.8 shows the data plots through the year. The Myrte site receives plenty of sunshine almost all year round: yearly summation of radiation was 1855 kWh/m², and the daily average was 5.08 kWh/m². Seasonal change of radiation is summarized in Figure 6.9. These data were directly used for the analysis.
Figure 6.8. Solar radiation data observed at the Myrte site in 2013. Data was acquired every 10 min.

Figure 6.9. Seasonal change of solar radiation at the Myrte site.
Assumed performance of the components

- **PV**
  According to the nominal data of PV arrays and setting information, the following parameters were put into HOMER:

  - size: 560 kWp
  - efficiency at standard condition: 13%
  - temperature coefficient of power: −0.46%
  - nominal operating temperature: 45°C
  - slope: 30°
  - ground reflectance: 20%

  HOMER considered the effect of temperature on the PV performance, although the details of this treatment are not clear.

- **DC/AC converter**
  Efficiency of the electric DC/AC converter from the DC bus to the AC grid was assumed as 95%.

- **Electrolyzer**
  Considering the overall system configuration and hydrogen production capacity of the Myrte system, the electrolyzer capacity was fixed at 2.0 kg/h (22 Nm$^3$/h) with power input of 110 kW$_{DC}$. This corresponds to constant efficiency of 61% (LHV) and 72% (HHV). The minimum operation ratio was set at 10% relative to the nominal value. Because, as mentioned above, the electrolyzer was assumed to be connected directly to the PV, no loss related to rectifying (DC/AC conversion) was considered. Losses related to load following were also not considered.

- **Fuel cell**
  Considering the overall power capacity of the Myrte system, the fuel cell power was set at 160 kW$_{AC}$. As shown in Figure 6.10, the efficiency at the rated operation was assumed as 50% (LHV), including DC/AC conversion. The minimum load ratio was set at 10% relative to the nominal value. The thermal energy utilization was not considered.

- **Hydrogen tank**
  The hydrogen tank’s capacity was set at 126 kg, the same as the real

![Figure 6.10. Assumed performance of fuel cell in the Myrte.](image)
tank. The tank was assumed to be initially empty. No loss related to hydrogen storage and transport was considered.

**Assumed cost**

The Myrte is a kind of showcase project for a grid-connected PV plant with a hydrogen hybrid system acting as an energy storage unit. As mentioned above, the installation cost was very high not only for the instruments but also for the civil engineering. In addition, since the Greenergy Box developed by Areva has not been fully commercialized, the capital and O&M (operation and management) costs have not been made public yet. Therefore, an economic analysis was omitted from the present analysis.

**Scope of the analysis**

In the present simulation, as mentioned above, the PV power was preferentially supplied to the electrolyzer, which was powered by only the PV output via the DC bus. The surplus power from the PV would then be fed to the grid via the DC/AC converter when the primary load could be ignored. When the PV output exceeds the minimum load ratio of the electrolyzer, the electrolyzer can be operated. In actual operation, the produced hydrogen (and oxygen) would be pressurized up to 35 bar by the electrolyzer and stored directly in the tank. However, HOMER could not take the gas pressure into account. The fuel cell operation was limited to four hours around dusk when the PV output had fallen the same as in real operation. Figure 6.11 shows the schedule of fuel cell operation set in HOMER. The timing of “forced on” (green) changed slightly with the seasonal change of sunset times. The fuel cell would operate at the “forced on” time every day as long as hydrogen had been stored. Time-step of the simulation was set at 10 min.

In the current simulation, based on the operation regime actually applied in the Myrte (Figure 6.6 and 6.11), the following parameters were examined:

- operating hours of the electrolyzer and fuel cell (FC)
- share of electrolyzer input in total PV power
- efficiency of electrolyzer, FC and round-trip
- overall power output of PV + FC compared to PV only
- state of charge (SOC) of hydrogen in the tank

![Figure 6.11. Operation schedule of PEMFC in the Myrte.](image)
6.5.2 Outputs from software analysis

Based on the solar radiation data taken every 10 min, the HOMER simulation was carried out for 52,560 (= 365 × 24 × 6) steps in one year. Figure 6.12 shows examples of the simulated power profiles of PV output, electrolyzer (ELY) input, and fuel cell (FC) output on specific days. As expected, the PV power was preferentially supplied to the electrolyzer, which fully followed the PV power and operated stably when PV power exceeded rated power (110 kW). Produced hydrogen was stored in the tank and utilized for power generation by the FC in the afternoon. Duration and power of FC operation depend on the amount of stored hydrogen. In the present schedule (Figure 6.11), the hydrogen stored during the daytime was entirely consumed in the afternoon of the same day, meaning that the hydrogen tank was empty every morning.

![Figure 6.12](image)

Figure 6.12. Examples of simulated power profile for one day in (a) January, (b) April, (c) July, and (d) October. (Time step: 10 min).

Figure 6.13 shows the monthly average power profile of PV output and electrolyzer input per day on the DC bus in Figure 6.7. Figure 6.14 shows the change of share of electrolyzer input to PV power. The share of electrolyzer input varied between 0.33 and 0.41.
Figure 6.13. Average power profile of PV output and electrolyzer input per day, by month (Summarized time-step: 1 hour).

Figure 6.14. Seasonal change of share of electrolyzer input to PV power.

Figure 6.15 shows monthly average power profiles of FC power and PV power supplied to the AC grid with and without H₂ production. Because the efficiency of the DC/AC converter between the DC bus and AC grid was set at 95%, PV power without H₂ production in Figure 6.15 (dashed line) is nearly the same as PV power in Figure 6.13. The difference between PV power with and without H₂ production (electrolyzer input) in Figure 6.15 represents the
energy converted to hydrogen by the electrolyzer. The power and duration of FC operation depended on the amount of hydrogen produced during the daytime. In winter, the FC could operate for about one hour at the rated power, after which it would power down because of the H₂ shortage. In summer, since relatively large amounts of H₂ were produced in the daytime, the FC could often operate for over two hours at the rated power.

Figure 6.15. Monthly average of power profile of fuel cell output and PV output with and without hydrogen production (Summarized time-step: 1 hour).

Figure 6.16 shows power production (kWh) in each month. Because the electric round-trip efficiency of the electrolyzer and fuel cell was around 30%, overall power generation was decreased by introducing a hydrogen storage system. When the H₂ storage system (left bars) was operating, the share of FC output was 16–22 %. The ratio of power generation with and without an H₂ storage system was around 0.7–0.8, as shown in Figure 6.17.

Figure 6.18 shows the accumulated operating hours of the fuel cell and electrolyzer in each month. Total operating hours in one year were 670 hours for the fuel cell and 3681 hours for the electrolyzer. As shown in Figure 6.19, the seasonal change of the electrolyzer operating hours was relatively large, while that of the FC was around two hours per day through the year, since the operating time was restricted (Figure 6.11).
Figure 6.20 shows the state of charge (SOC) profile and the frequency histogram of hydrogen in the tank through the year. When the electrolyzer and fuel cell were operated regularly following the planned regime, that is, the electrolyzer was operated as much as possible using PV power and the fuel cell was operated following the planned schedule (Figure 6.11) as long as stored hydrogen was available, the maximum storage was about 23 kg. In the real case, because the tank cannot ever be empty, the H₂ quantity range is between 18 and 125 kg, as noted above. Nevertheless, based on regular daily operation, the tank capacity can be reduced to about 50 kg under the present size of the electrolyzer and fuel cell.
Finally, the effect of component size was examined. The size of the FC was fixed at the present size of 160 kW, and the size of electrolyzer was varied from 50 kW to 300 kW. Figure 6.21 shows the effect of electrolyzer size. The larger electrolyzer produced a larger amount of hydrogen in a year, and the operation hours of FC were increased. This means that a larger amount of energy could be shifted from the daytime to the peak time. However, the ratio of PV power utilization was decreased, because the electric round-trip efficiency of the H₂ system was low at 30%. This can be recognized as a trade-off issue.
6.6 Summary

In the Myrte project, a hybrid system combining a grid-connected photovoltaic (PV) plant and a hydrogen energy storage unit was installed on the island of Corsica in France. Combining the PV power plant with hydrogen, Myrte adds value to a plentiful local resource—sunlight—and solves the constraint of intermittence related to the injection of fluctuating renewable energy into the relatively weak island grid. The major concept of the Myrte thus is daily peak load shaving of the AC grid. The electrolyzer (110 kW) is powered only by PV output (560 kWp) via the AC grid during sunny hours, when hydrogen and oxygen are produced and stored. The fuel cell (160 kW) is turned on and its power is fed back into the grid during the highest load hours in late afternoon.

An interesting feature of the Myrte is oxygen utilization. Produced oxygen as well as hydrogen were stored and fed to the FC for power generation. Applying oxygen to the cell operation realized positive effects on the system setup and performance compared to typical air feeding: high stack efficiency, simplifying the balance of plant (BOP) (no blower, no filter, no humidifier), a wide power range with similar efficiency, and faster dynamics (start and stop transient). However, oxygen storage poses extra cost and space requirements.

The Myrte has relatively large-scale storage tanks. The maximum capacity of the H₂ tank is 126 kg. Simulation results indicated that the tank capacity can be reduced to about 50 kg with the present size of electrolyzer and fuel cell based on regular daily operation. In addition, the larger electrolyzer produced a larger amount of hydrogen in a year, with the result that the operation hours of FC were increased. This means that a larger amount of energy could be shifted from daytime to peak time. Because the capacity of the Corsican grid is large, the effect of the peak shift on grid management would be limited.
7. **Japanese residential CHP**

7.1 **Background** [21]

In Japan, by FY 2007 energy-derived CO\(_2\) emissions had risen by 14.0% over the level in 1990, while household emissions showed a huge increase of 41.2%. There is thus strong pressure on the residential sector to reduce emissions.

The fuel cell offers high generation efficiency that can be raised further if the exhaust heat is recovered in a cogeneration system. For this reason, Japan’s national energy policy sets out ambitious goals for the deployment of fuel cells.

Residential polymer electrolyte fuel cell (PEFC) systems installed in houses to meet the demand for electricity and heat are positioned as a cogeneration power (combined heat and power; CHP) system that achieves energy savings and reduces CO\(_2\) emissions in the residential sector. Japan has been developing the technology as well as the pre-market infrastructure for commercialization and market creation.

7.2 **Outline of the Large-scale Stationary Fuel Cell Demonstration Project in Japan** [21]

With this as background, the Large-scale Stationary Fuel Cell Demonstration Project had since FY 2005 (April 2005) installed a large number of residential CHP systems in households nationwide to collect operation data on actual use. These CHPs were operated in a variety of residential settings and utilization patterns. The operation data collected was fed back to manufacturers to facilitate further improvements in reliability and durability, with the ultimate goal of commercialization and setting the stage for mass production and cost reduction. The project aimed to pave the way for a residential market for PEFCs by using the data to determine the level of technological maturity required for commercialization and to identify the issues for further R&D efforts. It was also expected that the project would bring public recognition to residential CHPs by introducing and exposing them as well as presenting their operating records to the general public.

The demonstration project was started in FY 2005 (April 2005) and terminated in FY 2008 (March 2009). As shown in Figure 7.1, the New Energy Foundation (NEF) provided funding to project operators (energy suppliers such as city gas and oil companies), who used the funds to purchase residential CHP systems from fuel cell manufacturers and install and operate them at regular detached houses. At participating homes (hereinafter called the “site”), the CHP systems produced electricity and heat (hot water) for daily consumption. Any data obtained on the operation of the systems (such as power supply, heat supply, fuel consumption, etc.) was collected by NEF via the project operators for analysis and evaluation. This data would assist in the determination of the technological maturity and identification of R&D challenges.
Table 7.1 shows the number of units the operators (energy suppliers) installed and operated by fuel type. Japan’s natural gas grid covers only urban areas, while LPG is typical in remote areas. Gases are used for both cooking and heating in residential houses, while kerosene is used only for heating. Overall, gases are a more widely used energy source than kerosene. In addition, reforming kerosene to hydrogen is more technically difficult than reforming gases. Therefore, about 90% of installed systems were fueled by gases (natural gas and LPG).

Table 7.1 Number of systems installed during the demonstration project [21,22].

<table>
<thead>
<tr>
<th>Type of fuel</th>
<th>FY2005</th>
<th>FY2006</th>
<th>FY2007</th>
<th>FY2008</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>City gas (Natural gas)</td>
<td>235</td>
<td>303</td>
<td>355</td>
<td>550</td>
<td>1443</td>
</tr>
<tr>
<td>LPG</td>
<td>245</td>
<td>399</td>
<td>424</td>
<td>482</td>
<td>1550</td>
</tr>
<tr>
<td>Kerosene</td>
<td>75</td>
<td>151</td>
<td>88</td>
<td>314</td>
<td>314</td>
</tr>
<tr>
<td>Total</td>
<td>480</td>
<td>777</td>
<td>930</td>
<td>1120</td>
<td>3307</td>
</tr>
</tbody>
</table>

Figure 7.2 shows the regional distribution of the 3307 sites where installation was carried out between FY 2005 and FY 2008. The project successfully installed and operated systems in all of Japan’s 47 prefectures. This broad distribution from Hokkaido in the north to Okinawa in the south allowed the acquisition of operating data under a wide range of climatic conditions, both warm and cold.
Figure 7.2. Regional distribution of installation sites (3307 sites installed between FY 2005 and FY 2008) [21,22].

Figure 7.3 shows the breakdown of participating households by family size and floor area. This information was based on a survey of the 777 sites installed in FY 2006, to which 440 sites responded. The family size varied from one to seven or more, with three- to five-person households dominating at 72.3%. The floor area also ranged widely, from 50 m$^2$ or less to 300 m$^2$ or more; houses of 100 m$^2$ to 200 m$^2$ accounted for 66.7%.

Figure 7.3. Households by family size and floor area [21,22].
7.3 System components and operation [21]

Residential CHP systems have been mainly composed of an FC unit and a hot-water tank. An FC unit includes a reformer, PEFC stack, rectifier, heat exchanger, and other balance of plants (BOPs). Figure 7.4 shows a schematic of FC installation and data collection; the data points are indicated by ◎. The fuel cell system was connected to a commercial grid, and the power and heat generated by the system were consumed by the household. The fuel flow, power output and power input, recovered heat, and electricity and heat consumptions of the site were measured.

Figure 7.4. Schematic of residential CHP installation and data collection [21,22].

Funding for the demonstration project was made available for CHP systems with a power rating of approximately 1 kW that were designed for installation in regular residential houses. To be eligible, the systems had to meet the following criteria:

a. Performance requirements
   Electrical efficiency of 30% or more (at rated operation; based on HHV) and 27% or more (at 50% load); gross efficiency of 65% or more (at rated; HHV) and 54% or more (at 50% load)

b. Manufacturer qualification
   Capable of providing 30 or more systems during the project term

c. Operator qualification
   Capable of installing 10 or more systems during the project term

d. Reporting requirements
   To operate the systems for two years or more (one year for systems installed in FY 2008) and report monthly data every quarter

Figure 7.5 shows power and thermal demand at 456 sites using natural gas or LPG systems that provided monthly data in 2008, out of a total of 930 sites installed in FY 2007. The figure represents the distribution of power and thermal demand by plotting the average power and thermal (hot water) demand at each site for the year. As this
The figure shows that demand for electricity and heat varied widely. Power demand ranged between 200 kWh and 2200 kWh per month, and thermal demand from 400 MJ to 4000 MJ per month; both show a difference of one order of magnitude. Average power demand was 652 kWh per month, and average thermal (hot water) demand was 1570 MJ per month. Compared to FY 2006, power demand was down by 3%, while thermal demand was up by 3%, but both distribution and average values could be described as essentially the same. The red dot-and-dash combination lines represent the amount of electricity and heat generated by a 1-kW system in 24-hour continuous operation, respectively. Compared to the region segmented by these red lines, the distribution of plotted data points indicates that the demand for heat was somewhat smaller than the amount of heat generated and that the CHP operation was, overall, driven by thermal demand. In other words, smart fuel cell operation requires a higher ratio of heat supply to demand and some kind of operational control that will allow the extraction of the maximum power output from the same thermal generation base.

**Figure 7.5.** Distribution of power and thermal demand among FY 2007 installation sites [21,22].
(Data from 456 sites, January–December 2008 (NG and LPG))

Figure 7.6 shows monthly changes in the power demand and CHP power supply as well as thermal demand (hot water) and FC hot water supply. The power demand curve has two distinct peaks (W-shaped): one in summer for air-conditioning and the other in winter for heating. Thermal demand, on the other hand, tended to increase in winter and decrease in summer (V-shaped curve), following the seasonal temperature changes.
Figure 7.6. Operation performance: monthly changes in FC power and heat supplied [21,22].
(Average data from 456 sites, January–December 2008 (NG and LPG))

Figure 7.7 presents comparisons between gaseous fuel systems (natural gas and LPG) and kerosene systems. The kerosene systems showed generation efficiencies that are a few points lower than those of city gas and LPG systems, but they were superior in thermal recovery efficiency by a few points. There are two likely reasons for the kerosene systems’ lower generation efficiency: a fundamental difference in the chemical process in that kerosene, with its heavy hydrocarbons, is more difficult to reform than natural gas and LPG, which have light hydrocarbons; and a difference in the system design in that kerosene systems require a vaporizer and a liquid pump due to the fact that kerosene is liquid.

Figure 7.7. Comparison between kerosene systems and natural gas (NG)/LPG systems [21,22].
(Actual performance for FY 2007 installation sites, averaged over January to December 2008)
Figure 7.8 shows the CO₂ emissions reduction achieved by installing a CHP system (data from January to December 2008 for FY 2007 installations of NG and LPG systems). The reduction of CO₂ emissions was evaluated on the basis of the emissions from fossil fuel power plants (oil and gas). The chart clearly depicts the significant influence thermal demand has on reducing CO₂ emissions, an effect similar to the primary energy reduction. The average reduction of CO₂ emissions was 75.1 kg per month, the equivalent of the CO₂ absorbed by 1670 m² of forest. Top-performing systems had a reduction of 100.1 kg per month on average, the same level of CO₂ absorbed by 2200 m² of forest.

![Graph showing CO₂ emissions reduction by CHP systems](image)

**Figure 7.8.** CO₂ emissions reduction by CHP systems [21,22].

(Data from 456 sites, January–December 2008 (NG and LPG))

In terms of reliability, Figure 7.9 shows the chronological trends of failure occurrences for natural gas and LPG systems by the year of installation and by the number of months of operation. Fault conditions generally tended to occur in the initial period after operation start-up; they then decreased in number after trouble-shooting, and flattened after one year or so of operation. Manufacturers have been incorporating feedback from the field operation into their designs and specifications every year with the aim of reducing costs ahead of commercialization. It is believed that such changes have been the cause of failures during initial operation. The FY 2007 systems represented substantial improvements over those installed in FY 2006, with a lower frequency of unforeseen shutdowns. Interim statistics for FY 2008 systems (failure information from October to December 2008 from 193 sites by three manufacturers; data available at the end of December 2008) indicate that unforeseen shutdowns had dropped further to approximately 0.29 per system per year. An unforeseen shutdown frequency of one per system per year means that any residential CHP system at any site might shut down due to a fault once a year. It is anticipated that a fault occurrence rate of less than roughly 0.3 per system per year, the level of the systems installed in FY 2008, would be the upper limit required for future commercialization.
Figure 7.9. Failure occurrences (unforeseen shutdowns) [21,22].
(natural gas and LPG systems)

As shown in Figure 7.10, over the three years from FY 2005 to FY 2008, a reduction of approximately 57% was achieved in the procurement price of residential CHP systems (the price reported by the installer/operator as the cost of a system consisting of a fuel cell unit and a hot water tank unit from a system manufacturer qualified for funding).

Figure 7.10. Reduction of system offering price [21,22].
Cost reduction and standardization of BOPs are essential for cost reduction of the total CHP system. METI and NEDO were leading not only the demonstration project but also the project focusing on the cost reduction and standardization of BOPs of the residential CHP system. The outcome of this BOPs project was directly reflected in the development of the CHP system demonstrated in the field. As shown in Table 7.2, a cost reduction of approximately 73% was achieved in the BOPs of residential CHP systems [23].

Table 7.2. Cost reduction of BOPs [23].

<table>
<thead>
<tr>
<th>Year</th>
<th>2005</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>JPY</td>
<td>JPY</td>
</tr>
<tr>
<td>Rotary machines (pump, blower)</td>
<td>140,000</td>
<td>60,000</td>
</tr>
<tr>
<td>Sensors (pressure, flow rate)</td>
<td>30,000</td>
<td>15,000</td>
</tr>
<tr>
<td>Valves</td>
<td>120,000</td>
<td>20,000</td>
</tr>
<tr>
<td>Rectifier</td>
<td>50,000</td>
<td>20,000</td>
</tr>
<tr>
<td>Heat exchanger</td>
<td>10,000</td>
<td>4,000</td>
</tr>
<tr>
<td>Water treatment instrument</td>
<td>50,000</td>
<td>4,000</td>
</tr>
<tr>
<td>Others (fittings, etc.)</td>
<td>120,000</td>
<td>15,000</td>
</tr>
<tr>
<td>Total</td>
<td>520,000</td>
<td>138,000</td>
</tr>
</tbody>
</table>

7.4 SWOT analysis

Based on the case study of Task 18, which represents the project activity in FY 2005 – FY 2008 [21], a SWOT analysis was performed on the Japanese CHP project. The outcomes of the analysis for each aspect of economic, environmental/technical, community/social, and regulatory are shown in Tables 7.3, 7.4, 7.5, and 7.6, respectively.
**Table 7.3. SWOT analysis for Japanese CHP project — Economical aspect.**

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demonstration of large-scale installation of fuel cell</td>
<td>High cost of the system</td>
<td>Suitable for large-scale market</td>
<td>Lack of general versatility in the world market</td>
</tr>
<tr>
<td>Diversification of energy source</td>
<td>Low degree of utilization rates at summer time</td>
<td>Cost reduction owing to large-scale installation</td>
<td>Rise of running cost due to increased fuel expenses.</td>
</tr>
<tr>
<td>Reduction of system cost</td>
<td>Business opportunity for small companies in BOP business</td>
<td></td>
<td>Difficulties at an installation for homes where the amount of the energy use is small</td>
</tr>
<tr>
<td>Synergy effect of energy infrastructure company and fuel cell supply company</td>
<td></td>
<td></td>
<td>Difficulties in internationalizing the market</td>
</tr>
<tr>
<td>Sufficiency of after support</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Table 7.4. SWOT analysis for Japanese CHP project — Environmental/technical aspect.**

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>Improvement of system efficiency and reliability</td>
<td>Lack of renewables</td>
<td>Potential for implementing hydrogen society</td>
<td>Lack of energy saving effect with low energy users</td>
</tr>
<tr>
<td>Demonstration of energy saving with CHP</td>
<td>Rigid specification of the system without considering user demand</td>
<td>Improvement of reliability of fuel cell</td>
<td>Decrease in interest for introducing RES</td>
</tr>
<tr>
<td>Low degree of energy saving rates at summer time</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low performance with kerosene system</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Table 7.5. SWOT analysis for Japanese CHP project — Community aspect.

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>Promotion of public understanding with large-scale installation</td>
<td>High cost of the system</td>
<td>Dissemination of distributed power generation</td>
<td>Difficulties at an installation for the home where the amount of the energy use is small</td>
</tr>
<tr>
<td>Received favorable reviews from the customers (pleasure in doing power generation at home)</td>
<td>Low degree of utilization rates at summer time</td>
<td>Increased understanding of need for saving energy</td>
<td>Lack of cost merit</td>
</tr>
<tr>
<td>Smooth installation owing to preliminary meetings</td>
<td>Frequent mechanical troubles at the initial stage of the project</td>
<td>Diversification of energy source</td>
<td></td>
</tr>
<tr>
<td>Contact with advanced technology</td>
<td></td>
<td>Promotion of R&amp;D based on user response</td>
<td></td>
</tr>
</tbody>
</table>

Table 7.6. SWOT analysis for Japanese CHP project — Regulatory aspect

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revision of domestic regulation by the government in advance of the project</td>
<td>Unified standard requires increased rigor</td>
<td>Reconsideration of regulation in reply to operation results</td>
<td>Inadequate regulations</td>
</tr>
<tr>
<td>Easy comparison and analysis with unified standard of power and efficiency</td>
<td></td>
<td>Internationalization of standards</td>
<td>Struggle for market between gas/oil company and power company</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Establishment of codes for test and evaluation</td>
<td>Lack of general versatility in the world market</td>
</tr>
</tbody>
</table>

7.5 Software analysis

7.5.1 Inputs for software analysis

System configuration and operation regime in HOMER
The demonstration project included three fuel options: natural gas (via grid), LPG, and kerosene. In the commercial phase after the demonstration project, natural gas–fueled CHP systems accounted for over 80% of the market (Figure 7.21). Therefore, this analysis concentrated on the systems fueled by natural gas. Based on the field test configuration (Figure 7.4), the virtual system configuration for simulation was fabricated in HOMER software as
shown in Figure 7.11. The fuel cell can act as a CHP unit and supply both electrical and thermal energy. In the HOMER analysis of the Japanese residential CHP system, a fuel reformer was included in the CHP unit and the reforming efficiency was included in the estimation of fuel cell performance. Similarly, a rectifier (DC/AC converter) was included in the CHP unit and the performance of the rectifier was considered in the estimation of fuel cell performance in the current analysis. A separate boiler (Figure 7.11) acted as a backup heat source, although the CHP systems installed in the residential houses contained a backup boiler inside the unit. Thus, both the fuel cell and the boiler are fueled by the same natural gas (grid). In Figure 7.11, “electric load” and “thermal load” designate the electric and thermal load for the single end user (residential house), respectively. In the HOMER analysis, it was difficult to consider the hot-water storage, and therefore a hot-water tank was not included in the system. Hot-water storage (buffering) was considered in preparing the thermal load.

The CHP operation always followed both the electrical and thermal loads simultaneously. The fuel, natural gas, was supplied from the grid on demand. The operation regime was different from the Lolland case. Because excess electricity cannot be fed back to grid in this application, the electrical and thermal energy produced by the CHP cannot ever exceed the electrical and thermal loads, respectively. If the CHP heat supply is inadequate for the thermal load, the shortfall of heat would be compensated by the backup boiler fueled by natural gas.

Figure 7.11. System configuration of Japanese residential CHP system in HOMER.

Electrical load and thermal load
Figure 7.6 showed observed data of the monthly average daily electrical and thermal loads in residential houses during the project. Figure 7.12 shows hourly profiles combining the data from Figure 7.6 with hourly or minutely profiles taken from the literature of the total daily electrical and thermal load in Japanese residential houses [24,25]. In addition, with regard to hot-water storage, the thermal load profile was little changed from the original data [24,25]. The load during late night (0100 to 0500) and daytime (1100 to 1600) was partially shifted to the morning (0600 to 1000) and evening and night (0500 to 1200). In the current simulation, only 12 profiles for each kind of load (Figure 7.12) were prepared for the year; thus, the hourly profile in a day was the same in each month. The yearly
assumed as 7847 kWh, and that of thermal energy was 5256 kWh.

**Figure 7.12.** Hourly profiles of electrical (a) and thermal (b) demands (loads) at one site in each month.

**Assumed performance of CHP**

As depicted in Figure 7.7, the electrical efficiency of the present CHP (1.0 kW\textsubscript{AC}), fueled by NG and LPG, varied from 30 to 32% (HHV), depending on the load. Because this efficiency includes fuel reforming, it is apparently lower than that of the hydrogen-fueled Lolland CHP, when the conversion efficiency from DC to AC is included in both cases. Because the current analysis was executed under the average load as noted, the power output from the CHP can be expected to be in the range of 200 to 300 kWh/month. Referring to Figure 7.7, the electrical efficiency of CHP was fixed at 31% (HHV), which corresponds to 34.4% (LHV). Similarly, the thermal efficiency of CHP was assumed at 43% (HHV), which corresponds to 47.7% (LHV). Thus, total CHP efficiency was calculated as 74% and 82.1% of HHV and LHV, respectively. In the real system, both efficiencies change depending on the load ratio (i.e., current density of FC) [26]. However, both the electrical and thermal efficiencies were assumed to be constant regardless of the load ratio. Because the time-step of the present simulation was one hour, the delay of power generation after a load change was not considered. The efficiency of the natural gas–fueled backup boiler was set at 80%, and the delay of heat supply after a load change was not considered either. Minimum load ratio was fixed at 25% in this case.

**Grid**

In the demonstration project, the reduction of CO\textsubscript{2} emissions was evaluated on the basis of emissions from fossil fuel power plants (oil and gas). The average CO\textsubscript{2} emission factor of fossil fuel power plants in Japan is 690 g/kWh, and this has been used for the present analysis of CO\textsubscript{2} emissions. The average CO\textsubscript{2} emission factor of the grid is in the range from 500 to 550 g/kWh.

**Assumed cost**
As shown in Figure 7.10, over the three years from FY 2005 to FY 2008, the capital cost of the CHP decreased by approximately 57%, and the cost range in the final year (FY 2008) was between ¥2.7 million and ¥5.0 million without subsidy. The cost analysis in the current simulation adopted the lowest price of ¥2.7 million. The average price of a Japanese hot-water boiler is about ¥250,000. The CHP unit includes the backup boiler and can cover all the functions of a boiler. In addition, the capital cost could not be allotted to the boiler in HOMER. Therefore, the cost difference between the CHP and the boiler was used as the CHP capital cost, which is $20,400 (¥2,448,000). Installation cost was not included in the capital cost, and operating and maintenance (O&M) cost was not considered either.

The grid cost of electricity and natural gas was also determined by the real cost in Japan. After the disaster in 2011, energy prices have increased in Japan. In particular, electrical power has risen about 20% since 2011. The current simulation used the most recent prices in Japan, although the demonstration project (April 2005 to March 2009) was executed before the disaster occurred. Based on the survey of grid costs in March 2015, the average energy price was determined as the constant grid price of the simulation regardless of demand, that is, ¥27.20/kWh ($0.227/kWh) for electricity and ¥213/Nm$^3$ ($1.77/Nm^3$) for natural gas. Both prices are including tax.

Assumed costs in the present analysis are summarized as follows:

- **CHP unit (1.0 kW$_{AC}$):** Capital: $22,500 (¥2,700,000), O&M: $0
- **backup boiler:** Capital: $2100 (¥252,000), O&M: $0
- **electrical power price:** $0.227/kWh (¥27.20/kWh) for buying
- **gas price:** $1.77/Nm$^3$ (¥213/Nm$^3$)

Scope of the analysis

In the present simulation, based on the actual operation of the residential CHP system, the CHP operation always followed both the electricity and heat loads simultaneously, and no excess energy production was permitted. The shortfalls of the electrical and thermal loads were compensated for by the AC grid and the backup boiler, respectively.

From the environmental/technical point of view, abundant data has been already presented by the project organizer (NEF), as shown in Section 7.3. In order to verify the current simulation, the calculated results have been compared with the observed data for share of FC output and reduction of CO$_2$ emissions.

From the economic point of view, the main parameters were the capital cost of the CHP unit, the electrical power price, and the natural gas price (grid). The analysis was able to specify the conditions for economic feasibility for the CHP installation versus existing energy facilities.

The time-step and lifetime of the simulation were set as one hour (60 min) and 10 years, respectively. The lifetime of all system components was assumed as the project lifetime (10 years), and the rate of interest was fixed at 0%.
7.5.2 Outputs from software analysis

Environmental/technical

In the present simulation, the CHP (FC) operation always followed the electrical and thermal loads simultaneously. As noted in Section 7.5.1, the electrical and thermal efficiencies of the CHP were assumed as 34.4% and 47.7% (LHV), and the rated power was set at 1.0 kW\textsubscript{AC}; the rated heat output was thus 1.39 kW. Because the minimum load ratio was set at 25% in this case, the CHP was operated when the electrical load exceeded 0.25 W and the thermal load exceeded 0.34 kW.

Examples of the calculated hourly profiles in January, April, and July are presented in Figures 7.13, 7.14, and 7.15, respectively. Because the hourly load profile in a day was the same in each month, each hourly profile of the CHP output also presents the monthly average profile in a day. In January (Figure 7.13), because thermal load was relatively high even in daytime, the CHP was stopped only in the late night (0200–0600). However, the thermal load in the morning was less than 1 kW, and the CHP could not cover a small part of the high electricity peak in the morning. In April (Figure 7.14), the thermal load in the afternoon was low, and the CHP would stop twice a day. As in January, the CHP operation in April was restricted by the thermal load almost all day except for the evening. Because the electricity load was lower than in January, the share of the CHP power supply to the electrical load must be higher. In July (Figure 7.15), since the thermal load was very low, the CHP operation was restricted only in the evening and night (1600–2400) and could not reach the rated operation through the daytime. The thermal energy share of the CHP

![Figure 7.13. Hourly profiles of (a) electricity and (b) thermal energy in January.](image)

![Figure 7.14. Hourly profiles of (a) electricity and (b) thermal energy in April.](image)
was thus very high, while the electricity share was very low.

Figure 7.16 presents the monthly average share of the CHP output. The share of thermal energy depended on the load; that is, the share was high for low load and low for high load. As for the share of electricity, because the CHP operation nearly followed the thermal load, the seasonal change showed a different behavior than that of the thermal share. In particular, the share in summer was significantly lower than in winter, because the electricity load in summer was relatively high due to the demand for air-conditioning, while the thermal load was very low. In general, the seasonal change of the shares of electricity and thermal energy was in agreement with the observed results presented in Figure 7.6.

Figure 7.15. Hourly profiles of (a) electricity and (b) thermal energy in July.

Figure 7.16. Calculated results of monthly average production of (a) electricity and (b) thermal energy.
Figure 7.17 shows a comparison of the measured data and simulated results for the shares of the CHP output allotted as electrical and thermal energy. The measured data is actually calculated data using the demand and supply data presented in Figure 7.6. In terms of electrical share, the present simulation results show good agreement with the measured data through the year, while the simulated thermal share deviates from the measured data somewhat. The present calculation thus could simulate the real CHP operation well, although the reason for the differences in thermal share is not clear at present. It can be concluded that the CHP operation was restricted by the limit of thermal load under the present operation regime.

![Figure 7.17. Comparison between measured data and simulated results for share of CHP output.](image)

Regarding CO₂ emissions per site, Table 7.7 shows a comparison between with and without the CHP installation. Based on a grid CO₂ emission factor of 690 g/kWh, which is the assumed value of the grid power from only fossil fuel plants, the present calculation results show that the installation and operation of a CHP reduced CO₂ emissions by 1372 kg/yr, a 20.7% drop. The observed data presented in Figure 7.8 shows that CO₂ emissions were reduced by about 1200 kg/yr per site. The calculated result agrees with measured data sufficiently, though it is slightly higher.

When we use a CO₂ emission factor of 500 g/kWh, which is the average value for the grid power from all types of power plants, the CO₂ emissions can be calculated as 5136 kg/yr without a CHP installation and 4314 kg/yr with the CHP installation. In this case, the reduction of CO₂ emissions per site is 822 kg/yr, or a reduction of 16.0%.
Table 7.7. Comparison of emissions with and without CHP installation.

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emissions (kg/yr)</th>
<th>Emissions (kg/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Grid</td>
<td>Grid/CHP</td>
</tr>
<tr>
<td>Carbon dioxide</td>
<td>6,627</td>
<td>5,255</td>
</tr>
<tr>
<td>Carbon monoxide</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Unburned hydocarbons</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Particulate matter</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Sulfur dioxide</td>
<td>3.14</td>
<td>1.98</td>
</tr>
<tr>
<td>Nitrogen oxides</td>
<td>3.92</td>
<td>2.48</td>
</tr>
</tbody>
</table>

Economic

Because the objective CHP system relies fully on the electricity and natural gas grids, economic feasibility was evaluated using the balance of the CHP capital cost and the reduction of operating costs owing to the CHP installation. As mentioned, the present CHP unit included a backup boiler; however, the capital cost cannot be appropriated for the boiler in HOMER. Thus the capital cost difference between the CHP unit and the boiler was applied to the CHP (FC) capital cost in the present analysis, that is, $20,400, when the boiler capital cost was assumed as $2100. Figure 7.18 shows a cash flow comparison over 10 years between the conventional case with no CHP installed and a case where a CHP is installed. Figure 7.19 shows the cost composition of a system with a CHP. When no CHP is installed, there is no specific installation cost, and the cash flow each year consists of only the grid cost of electricity and natural gas. In the case of a system with a CHP installed, the CHP capital cost ($20,400) is appropriated in year 0, and the cost in years 1 to 10 consists of only the grid costs (Figure 7.19), just as in the uninstalled case (although the annual costs for the installed case were lower owing to the share of CHP, when operating and maintenance (O&M) costs of the CHP are not considered). The total cost over 10 years could be calculated as $28,280 for the CHP uninstalled case and $47,507 for the installed case. Therefore it can be clearly concluded that, without incentives, the CHP installation is not economically feasible under the present cost conditions.
As shown in Figure 7.10, a 57% cost reduction was achieved over the three years to the end of the project (March 2009), and further reduction could be expected. In the present study, a sensitivity analysis was executed as a function of the capital cost of the CHP (Figure 7.20). When the capital cost was decreased, the area for the CHP installation system (black area) expanded in the optimal system diagram; however, it is difficult to achieve economic feasibility under the present Japanese grid costs even when the CHP capital is one-fourth of the present ($5100 CHP only; $7200 (¥864,000) CHP + boiler).
Updates in commercial phase

Residential CHP systems were to be launched onto the market in May 2009, just after the demonstration project, under the standard name of “Ene-Farm.” Although there were three options for fuel type during the demonstration project (natural gas, LPG, and kerosene), commercial products have been limited to natural gas and LPG. Figure 7.21 shows that the number of residential CHPs installed has increased each fiscal year, and exceeded 100,000 in September 2014. PEFCs have dominated the market for residential CHPs, although CHPs with a solid oxide fuel cell (SOFC) were also launched onto the market in 2012. Since the disaster, products combining a CHP and a PV or a CHP and a battery (UPS) have been developed and sold.

Figure 7.22 shows the reduction of the CHP capital cost from 2005 to 2015. In the case of Panasonic [26], a 43% cost reduction was achieved even after the project, and the rated power of the CHP was reduced from 1 kW in 2009 to 0.75 kW in 2011. The rated power of the latest Panasonic version, released in 2015, is 0.70 kW. Performance has also been improved since the project.

Table 7.8 shows a comparison between nominal data from the previous type at the end of the project and the latest version. Applying the data from the latest version into HOMER, a simulation of CHP operation was performed under the same load conditions as the previous. The simulation results of the latest type are also listed in Table 7.8 and compared with those of the previous type. The monthly change of share in a year is presented in Figure 7.23. On the basis of the simulation results, the power output of the latest type of CHP was over 90% of the previous type, even though the rated power was reduced to 70%. Operating hours and capacity factor have been improved due to the size reduction. These facts can be explained by not only the performance improvement but also the optimization of
size for the Japanese residential energy load.

Figure 7.21. Number of CHP installations in commercial phase since 2009 (data for 2009 and 2010 contains no information about fuel type) [27].

Figure 7.22. Reduction of CHP capital cost (The capital cost of Panasonic products is presented for the commercial phase [26]).
Table 7.8. Comparison of nominal data and simulated operation of CHP [21,26].

<table>
<thead>
<tr>
<th></th>
<th>Previous type</th>
<th>Latest type</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Nominal data</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Release year</td>
<td>2008</td>
<td>2015</td>
<td></td>
</tr>
<tr>
<td><strong>Rated power</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electric</td>
<td>1.0</td>
<td>0.7</td>
<td>kW</td>
</tr>
<tr>
<td>Thermal</td>
<td>(1.4)(^{(a)})</td>
<td>1.01</td>
<td>kW</td>
</tr>
<tr>
<td><strong>Efficiency at rated</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>operation</td>
<td>Electric</td>
<td>34.4</td>
<td>% (LHV)</td>
</tr>
<tr>
<td></td>
<td>Thermal</td>
<td>47.7</td>
<td>% (LHV)</td>
</tr>
<tr>
<td><strong>Capital cost</strong></td>
<td>JPY</td>
<td>¥3,290,000(^{(b)})</td>
<td></td>
</tr>
<tr>
<td></td>
<td>USD(^{(c)})</td>
<td>$27,417</td>
<td>$13,333</td>
</tr>
</tbody>
</table>

**Simulated results**

<table>
<thead>
<tr>
<th></th>
<th>Previous type</th>
<th>Latest type</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power production</td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Electric</td>
<td>2,891</td>
<td>2,635</td>
<td>kWh/yr</td>
</tr>
<tr>
<td>Thermal</td>
<td>3,923</td>
<td>3,790</td>
<td>kWh/yr</td>
</tr>
<tr>
<td>Mean output</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electric</td>
<td>0.603</td>
<td>0.459</td>
<td>kW</td>
</tr>
<tr>
<td>Thermal</td>
<td>0.818</td>
<td>0.660</td>
<td>kW</td>
</tr>
<tr>
<td>Yearly share</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electric</td>
<td>37</td>
<td>34</td>
<td>%</td>
</tr>
<tr>
<td>Thermal</td>
<td>75</td>
<td>72</td>
<td>%</td>
</tr>
<tr>
<td>Operation hours</td>
<td>4,794</td>
<td>5,738</td>
<td>hr/yr</td>
</tr>
<tr>
<td>Number of starts</td>
<td>549</td>
<td>519</td>
<td>starts/yr</td>
</tr>
<tr>
<td>Capacity factor</td>
<td>33.0</td>
<td>43.0</td>
<td>%</td>
</tr>
</tbody>
</table>

\(^{(a)}\): Estimated value from efficiencies.
\(^{(b)}\): Average value at the end of the project.
\(^{(c)}\): $1=¥120

Figure 7.23. Monthly change of share with the latest type of CHP.
Economic feasibility was also examined for the latest type of CHP released in 2015. As with previous type (2008), the cost difference between the whole CHP unit ($13,333) and the backup boiler ($2083) is assumed as the CHP capital cost ($11,250). Figure 7.24 shows the optimal system diagram as functions of power price and natural gas price. It can be suggested that the residential CHP system can achieve economic feasibility when the CHP capital including the boiler is reduced to under about $4900 (= $2800 + $2100) (¥588,000) under the present Japanese grid costs.

![Figure 7.24. Sensitivity analysis results for optimal system as functions of power price ($/kWh) and natural gas price ($/m³). CHP capital multiplier is assumed as (a) 0.50 and (b) 0.25 when the initial CHP capital cost is set at $11,250. Red circles represent grid cost area of power and natural gas in Japan.](image)

The reduction of CO₂ emissions with the latest type was calculated as 1451 kg/yr (21.9%) when the CO₂ emission factor of the grid was set at 690 g/kWh. When the factor was set at 500 g/kWh, CO₂ emissions were reduced by 951 kg/yr (18.5%). Figure 7.25 shows the calculated relationships between CO₂ reduction and the CO₂ emission factors of the electricity grid for the precious 1-kW FC system and the latest 0.7-kW FC system. Because of the improvement in efficiency, CO₂ emissions from the latest type were lower than those from the previous type, though the share was slightly decreased (Table 7.8). It is suggested that the reduction of CO₂ emissions can be achieved when the CO₂ emission factor of electricity grid exceeds about 200 g/kWh.
7.6 Summary

In Japan, the Large-scale Stationary Fuel Cell Demonstration Project (2005–2009) had since 2005 installed a large number of residential CHP systems (1 kW_{AC}) in households nationwide to collect operation data on actual use. These CHPs were operated in a variety of residential settings and utilization patterns. During this project, any data obtained from the operation of the system (such as power supply, heat supply, fuel consumption, etc.) was collected for analysis and evaluation by the project organizer (NEF) via the project operators. The change of system installation cost was provided by the organizer. These data were very useful for the present analysis to assist in the determination of CHP technological maturity and economic feasibility.

A software analysis was performed based on the monthly average value of observed load data of electricity and thermal energy, and the calculated results were compared to the observed data of the share of CHP in electrical and thermal load. The calculated results showed good agreement with the observed data. The calculated result of CO\textsubscript{2} reduction was also in good agreement with the published data. In this case, because reverse power flow to the AC grid was not permitted and thermal demand was relatively low in Japan (particularly in summer), the CHP operation was restricted by the thermal demand. Based on the software analysis, at the original standard scale of 1 kW_{AC}, yearly operation time was calculated as about 4800 hours and the capacity factor of the CHP was 33%. CO\textsubscript{2} reduction per site was calculated as 822 kg/yr, which corresponds to a 16.0% reduction, based on the average value of the CO\textsubscript{2} emission factor of the Japanese grid.

In May 2009, just after the demonstration project, residential CHP systems were launched onto the market under the standard name of “Ene-Farm.” The number of residential CHPs installed in each fiscal year has been successfully increased and exceeded 100,000 in September 2014. In these commercial products, considering the limit of thermal
demand, the rated power was reduced from 1 kW\textsubscript{AC} to 0.7 kW\textsubscript{AC}. Performance was improved even more. In the latest version of the commercially available CHP, with a rated power of 0.7 kW\textsubscript{AC}, yearly operation time was calculated as about 5700 hours and the capacity factor reached 43\%, while CO\textsubscript{2} emissions dropped by 951 kg/yr, which corresponds to an 18.5\% reduction. It can be stated that a reduction of about 20\% in CO\textsubscript{2} emissions is major progress in urban areas.

Thanks to the efforts of suppliers and governmental support, the capital cost of residential CHPs has been significantly reduced over the last 10 years, from ¥7.7 million to ¥1.6 million. However, it can be suggested that residential CHP systems will achieve economic feasibility when the CHP capital cost including the boiler is reduced to about $4900 (= $2800 + $2100) (¥588,000) or less under the present Japanese grid costs. Although this cost target might be a considerably severe figure for the manufacturer, it seems not impossible in view of the current trend in cost reduction.
8 The Octagon

8.1 Background

Because natural gas can achieve higher carbon efficiency with lower emissions of harmful exhaust gases such as NOx and SOx, it is a major source of electricity generation through the use of cogeneration with gas turbines, steam turbines, and fuel cells. As the US Environmental Protection Agency noted [28], combined heat and power (CHP) can play an important role in meeting the energy needs of the US as well as in reducing the environmental impact of power generation. CHP offers benefits in the following areas [28]:

- **Efficiency** — CHP requires less fuel to produce a given energy output, and avoids transmission and distribution losses that occur when electricity travels over power lines.
- **Reliability** — CHP can be designed to provide high-quality electricity and thermal energy to a site regardless of what might occur on the power grid, decreasing the impact of outages and improving power quality for sensitive equipment.
- **Environmental** — Because less fuel is burned to produce each unit of energy output, CHP reduces air pollution and greenhouse gas emissions.
- **Economic** — CHP can save facilities considerable money on their energy bills due to its high efficiency and can provide a hedge against unstable energy costs.

In addition, US natural gas prices have been decreasing in recent years as a result of shale gas development. It would be interesting to evaluate the ways in which CHP can benefit communities under such favorable conditions.

8.2 Outline of The Octagon [29,30]

The Octagon is a 500-unit, multi-family luxury residential building located on Roosevelt Island in New York, NY (Figures 8.1 and 8.2). The 14-story wings contain the residential areas, while the common areas are housed in the original historic Octagon. The Octagon was originally built in 1814 but fell into disrepair over the years. In 2006 it was completely renovated to its current condition. In 2011 Becker + Becker, the project’s developer and architect, planned and installed a CHP system with a fuel cell in order to be as energy efficient as possible. It made history by becoming the first residential building in New York State to be powered and heated by a fuel cell.

The project was supported by $1.2 million in financial incentives from the New York State Energy Research and Development Authority (NYSERDA), a body established to protect the environment of New York by promoting energy efficiency and the use of renewable energy sources. These efforts are key to developing a less polluting and more reliable and affordable energy system for all New Yorkers. Collectively, NYSERDA’s efforts aim to reduce greenhouse gas emissions, accelerate economic growth, and reduce consumer energy bills. NYSERDA works with stakeholders throughout New York, including residents, business owners, developers, community leaders, local government officials, university researchers, utility representatives, investors, and entrepreneurs.
In addition to the fuel cell, The Octagon is also powered by a 50-kW PV, the largest PV array on a residential building in New York City. The CHP system converts natural gas to electricity and heat through a combustion-free electrochemical process to provide power and heat to meet the majority of the apartment building’s energy demand. The energy efficiency achieved by the fuel cell is higher than that of the energy received from the grid, and emissions are negligible. Additionally, the fuel cell’s process heat is captured to satisfy the building’s space and domestic water heating requirements.

Figure 8.1. The site of The Octagon on Roosevelt Island, New York [31].

Figure 8.2. Views of The Octagon [30].

The specifications of the CHP system (Figure 8.3) installed in The Octagon are as follows [30]:

- CHP unit: UTC Power PureCell™ 400 (Doosan Fuel Cell America) — phosphoric acid fuel cell (PAFC)
• installation date: 2011
• operation start-up: May 2011
• generating power: 400 kW
• heat generation: 1.7 MMBtu/h (ca. 500 kW)
• CHP design efficiency: 90%
• total cost – FC & installation: $3,000,000 ($2,175,000 for CHP unit + installation and existing system tie-in and upgrades)
• maintenance cost: $70,000/yr
• total incentives: $1,200,000

Figure 8.3. PureCell® 400 (Doosan Fuel Cell America) [30].

8.3  System components and operation

The current case study focused on the natural gas–fueled CHP application using PAFC that was installed in The Octagon. Although The Octagon is also powered by a 50-kW PV, the study has not considered the PV contribution at all. The energy utilization regime is the same as that of the Japanese residential CHP, although the scale and the type of fuel cell are different. The natural gas fuel is supplied to the CHP unit via the grid and converted to hydrogen by the reformer in the unit. Hydrogen is used for the PAFC, which produces power and heat simultaneously. The produced electricity and heat are supplied to the residential demand of The Octagon as shown in Figure 8.4.
The CHP unit with PAFC was initially developed by UTC Power. Its fuel cell business was moved to ClearEdge in December 2012, and in July 2014 ClearEdge was purchased by South Korean conglomerate Doosan Group. Doosan Fuel Cell America was established to take over the fuel cell manufacturing business from ClearEdge. Doosan Fuel Cell America [33] currently manufactures and provides the PureCell® 400 (400 kW AC at rated) with the same brand, specification, and performance as that of UTC Power and ClearEdge.

PAFCs were the first fuel cells to be commercialized. UTC had already developed a 4-kW PAFC in 1968. Since then, the PAFC has been scaled up and field-tested, and its stability, performance, and cost have been improved significantly. The electrolyte used in the PAFC is a solution of phosphoric acid (H₃PO₄) saturated in a silicon carbide matrix (SiC). Operating temperature is about 150 to 210°C, which can provide a higher quality of thermal energy than the PEFCs used in other projects in this report. Such characteristics have made the PAFC a good candidate for early stationary applications.

The CHP unit is composed of main three sections: a fuel processor, a fuel cell stack, and a power conditioner (Figure 8.5). The natural gas supplied to the unit is reformed to hydrogen by the fuel processor (reformer). Hydrogen is supplied directly to the PAFC stack for cogeneration of heat and power. In the case of the PureCell® 400, 400-kW AC power can be supplied to the electrical load via the unit’s power conditioner, and thermal energy can be supplied to the thermal load at two temperature levels: high-grade (HG) heat at about 120°C, and low-grade (LG) heat at about 60°C [34]. The suppliers of the PureCell® 400 have guaranteed a stack life of 10 years. Table 8.1 lists the specifications of the PureCell® 400.

![Figure 8.4. Schematic of heat flow in The Octagon [32].](image-url)
All projects supported by NYSERDA have posted their operating data on the Internet to the extent possible [29]. In the case of The Octagon, all of the CHP operating data has been posted, although the facility demand data has not. Therefore we could not evaluate the amount by which electricity generated exceeded demand, although the excess electricity did go back to the grid without reimbursement. Figure 8.6 shows hourly ambient temperatures at the site.
and the runtime of the CHP per hour through the year (2012). Most of the spikes in Figure 8.6(b) represent data missing. Thus, it can be seen that the CHP could be operated stably through the year. This corresponds to the “baseload operation” mode in Table 8.1.

Figure 8.7 shows hourly electrical output and useful heat recovery. As seen in Figure 8.7(a), the CHP was operated stably at its rated electric power of 400 kW in winter and summer, while it was operated at partial load below 400 kW in some hours during spring and fall. Even during partial load operation, the runtime was kept at full hours (Figure 8.6(b)). Figure 8.7(b) shows a profile of useful heat recovery, which might be calculated by the difference between total heat output from the CHP and exhaust heat released from the cooling module (Figure 8.4) and might represent the actual thermal load of the site, although the thermal demand data has not been published. As mentioned, the CHP unit can produce HG and LG heat, and total energy can be calculated as 446 kW (= 188 + 258 kW, 1.52 MMBtu) from the baseload operation mode listed in Table 8.1. In actual operation at The Octagon, only LG heat was applied to the thermal load when the thermal energy supplied from the CHP reached 500 kW (1.7 MMBtu). Over one year of operation, total electrical production was 3,381,004 kWh, and total recovered heat was 1,031,618 kWh. Assuming the nominal output of the CHP mentioned above (400 kW electricity and 500 kW heat), the capacity factor was 96.5%, and the thermal utilization ratio was 23.6%.

Figure 8.8 shows the electrical efficiency and overall efficiency of the CHP calculated from the observed data. The electrical efficiency (Figure 8.8(a)) is somewhat higher than the nominal 42% presented in Table 8.1. The reason for this is not clear at present, although the flow rate of natural gas might have been underestimated. Electrical efficiency was nevertheless stable through the year, which implies that the decrease of electrical efficiency caused by the partial load operation was limited. On the other hand, because overall efficiency is the sum of electrical efficiency and heat recovery efficiency (thermal efficiency), overall efficiency was definitely affected by the heat recovery, as shown in Figure 8.8(b).

Figure 8.6. (a) Observed hourly data of ambient temperature profile, and (b) runtime of CHP per hour, 2012 [29].
Figure 8.7. Observed hourly data of (a) electrical output, and (b) useful heat recovery of CHP, 2012 [29].

Figure 8.8. Observed hourly data of (a) electrical efficiency, and (b) overall efficiency of CHP, 2012 [29].

Because the present CHP system is fully reliant on both the electricity and natural gas grids, grid information is important for system evaluation. Figure 8.9 shows the monthly change of electricity prices in New York State (NY) and the United States (US) since 2011. Electricity prices vary widely from region to region in the US, and the price in NY has been significantly higher than the national average. According to the project organizer (Becker+Becker), the residential consumer price was applied to The Octagon, and it worked out to be about $0.21/kWh including all fees and taxes as of June 2013.

Figure 8.10 shows the monthly change of natural gas prices in NY and the US since 2000. Unlike electricity prices, there is little variation in natural gas prices around the country. In addition, prices have been decreasing since around 2009. The project organizer states that The Octagon received the natural gas rate for commercial users, which was about $0.98/therm ($0.36/Nm$^3$ based on the heat content data in NY of 1029 MMbtu/ft$^3$) [35].

Figure 8.11 shows electricity grid information for NY and the US related to CO$_2$ emissions. Figure 8.11(a) shows the CO$_2$ emission factors of the grid in NY and the US. The CO$_2$ emission factor for the entire US shows a
downward tendency and was about 560 g/kWh in 2010. That of the NY region grid (NPCC NYC/Westchester) has been much lower than that for the whole country and was about 280 g/kWh in 2010, half the US average. Figure 8.11(b) shows the composition of electricity generation in New York State by source. About a quarter of the power supplied to the NY grid is produced by renewables, including hydro, and about 40% comes from fossil fuel plants (petroleum, coal, and natural gas). It should be emphasized that the proportion produced by fuels that have higher CO$_2$ emission factors than natural gas, namely petroleum and coal, is very low at about 2.0%. Thus, if a CHP application is to make a meaningful contribution to reducing CO$_2$ emissions in NY, it will have to be highly efficient.

![Figure 8.9. Monthly change of grid electricity price in NY and US [36].](image1)

![Figure 8.10. Monthly change of grid natural gas prices in NY and US [36].](image2)
Figure 8.11. Electricity grid information for NY and US: (a) change of CO$_2$ emission factor of the grid, and (b) composition of electricity generation in New York State by source [35,36].

8.4 SWOT analysis

Mr. Robert Friedland of Proton Onsite performed a fundamental evaluation of the CHP system in The Octagon, based on site visits and interviews at Becker+Becker. The outcomes of the analysis for economic, environmental/technical, community/social, and regulatory aspects are shown in Tables 8.2, 8.3, 8.4, and 8.5, respectively.

Table 8.2. SWOT analysis for Octagon project — Economical aspect.

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>Uses inexpensive natural gas to create electricity. Recent declines have improved payback by 6 months</td>
<td>High cost of equipment makes viability questionable without incentive</td>
<td>Compatible with existing infrastructure</td>
<td>Competing technologies</td>
</tr>
<tr>
<td>Grid independence provides value to residents of building</td>
<td>Cannot sell back power to the grid in New York City</td>
<td>Natural gas prices are expected to stay low for some time, at least in the US</td>
<td>Life cycle costs are largely unproven</td>
</tr>
<tr>
<td>Tax incentives made project viable</td>
<td>Suitable for large-scale markets</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Compatible with smart grid technologies</td>
<td></td>
</tr>
</tbody>
</table>
### Table 8.3. SWOT analysis for Octagon project — Environmental/technical aspect.

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reduced environmental impact and carbon footprint</td>
<td>Maturity of technology still unproven</td>
<td>Reduced environmental impact</td>
<td>Climate change debate</td>
</tr>
<tr>
<td>Low noise compared to other on-site generation technologies</td>
<td>Natural gas still has some greenhouse gas emissions</td>
<td>Emergence of large-scale markets</td>
<td>Inadequate legislative policy</td>
</tr>
<tr>
<td>CO2 emissions average 1120 lb/MWh</td>
<td>Lack of codes and standards governing interconnection and siting</td>
<td>Reduced costs eliminate need for incentives and improve overall economics</td>
<td>Competing technologies</td>
</tr>
<tr>
<td>Improvement of system efficiency and reliability</td>
<td>Unpredictable life and maintenance costs</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Table 8.4. SWOT analysis for Octagon project — Community aspect.

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>Prestige of being seen as “green”</td>
<td>Lack of codes and standards</td>
<td>New job creation</td>
<td>Climate change debate</td>
</tr>
<tr>
<td>Received favorable reviews from the tenants of the building</td>
<td>Lack of education of engineers and building owners</td>
<td>Business and economic growth</td>
<td>Cost of the system versus the overall environmental benefits</td>
</tr>
<tr>
<td>Uses 35% less energy than a baseline residential building - certified LEED silver</td>
<td>Some initial concern over appearance and noise but now largely unnoticed and quieter than traffic</td>
<td>Attract new investment and funding</td>
<td>Lack of awareness</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Publicity and prestige</td>
</tr>
</tbody>
</table>

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Table 8.5. SWOT analysis for Octagon project — Regulatory aspect.

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>No special permits required for installation</td>
<td>Lack of codes and standards</td>
<td>Inform utilities on interconnection issues for wider adoption</td>
<td>Customer reluctance to switch from grid</td>
</tr>
<tr>
<td>Grid independence</td>
<td>Inexperience of AHJs</td>
<td>Potential large market opportunity</td>
<td>Politics could change economics or ability to sell power to grid</td>
</tr>
<tr>
<td>Low availability and high cost of fuel cells</td>
<td>Huge arbitrage of spread between natural gas and electricity</td>
<td></td>
<td>Not enough players enter the market</td>
</tr>
<tr>
<td>Lack of awareness and potential benefits</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Every installation is unique – no consistent market</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

8.5 Software analysis

8.5.1 Inputs for software analysis

System configuration and operation regime in HOMER

The CHP system in The Octagon relies fully on the electricity and natural gas grids, just like the Japanese residential CHP. Thus, the apparent system configuration in HOMER was the same as in the Japanese residential case (Figure 8.12). It was composed of a fuel cell that can act as a CHP unit and supply both electrical and thermal energy. As in the Japanese residential CHP system, the CHP unit included a fuel reformer, and reforming efficiency was also included in the estimation of fuel cell efficiency in the HOMER analysis. Similarly, a rectifier was included in the CHP unit, and the performance of the rectifier was considered in the estimation of fuel cell performance in the HOMER analysis. A separate boiler was also included in The Octagon, and it is still active (Figure 8.4).

The CHP operation always followed both the electrical and thermal loads simultaneously. Because excess heat could be released from the cooling module of The Octagon, the operation regime was different from that of the Japanese case. The project organizer noted that excess electricity could be fed back to the grid (without reimbursement) [30]. However, because the CHP operated at partial load during certain hours (Figure 8.7(a)), the reverse power flow has not been considered in the current analysis. Therefore, the electrical power produced by the CHP can never exceed the electrical load, while the thermal energy from the CHP can exceed the thermal load. If the
CHP heat supply was inadequate for the thermal load, the shortfall of heat would be compensated by the backup boiler fueled by natural gas.

![Diagram of equipment configuration](image)

**Figure 8.12.** System configuration of The Octagon CHP system in HOMER.

**Electrical load and thermal load**

As mentioned above, the electrical load profile of The Octagon is unknown, other than that the base load is approximately 600 kW [30]. Thus, an electrical load profile was picked up from the data from a similar apartment building posted on the NYSERDA website. That building was the Archstone Chelsea, a 266-unit, multi-family luxury residential building located in Manhattan [32]. However, the base load of the Archstone Chelsea is about 75 kW, lower than that of The Octagon, and so the electrical load profile of the Archstone Chelsea was enlarged to match the load level of The Octagon. Finally, the data was modified slightly, based on advice from the project organizer (Becker+Becker).

Regarding thermal load, as mentioned, it could be suggested that the observed data for useful heat recovery (Figure 8.7(b)) represents the actual thermal load of the site. As such, it has been used as the thermal load in the current analysis.

Figure 8.13 shows the hourly profiles of electric and thermal load used in the analysis. The yearly total demand for electricity was assumed as 6,279,807 kWh and that for heat as 1,025,283 kWh. The time-step of the present simulation was set at one hour (60 min).
Figure 8.13. Hourly profiles of (a) electrical and (b) thermal load at The Octagon over one year.

Assumed performance of CHP
As depicted in Table 8.1, in baseload operation mode the nominal and overall electrical efficiencies of the CHP unit are 42% and 90%, respectively. In addition, the observed electrical efficiency was stable at a high level regardless of the load ratio. Therefore, the electrical efficiency of the CHP was fixed at 42% (LHV), including the conversion efficiency from DC to AC. The overall CHP efficiency was fixed at 90% (LHV). Because The Octagon uses only low-grade (LG) heat in actual operation, the difference in heat grade was not considered in the analysis. The efficiency of the natural gas–fueled backup boiler was set at 80%. Because the time-step of the present simulation is one hour, the delay of power generation in relation to load change was not considered. The minimum load ratio of the CHP was fixed at 25%.

Grid
Based on the inspection noted in Section 8.3, the CO₂ emission factor of the electricity grid was assumed as 282 g/kWh. However, the analysis did not consider any other air pollution.

Assumed cost
The HOMER analysis of The Octagon used real costs. Because the CHP unit does not include a backup boiler and The Octagon relied on its existing boilers, the cost of backup boilers was not considered.

The assumed costs in the present analysis are as follows:

- CHP unit (400 W<sub>AC</sub>): Capital: $3,000,000, O&M: $70,000/yr (@$8000/h)
- Power price: $0.21/kWh for buying
- Gas price: $0.36/Nm<sup>3</sup> ($0.98/therm)

Scope of the analysis
In the present simulation, the CHP operation always followed the loads of both electricity and heat simultaneously, although there was no limit on excess heat released from the cooling module. The shortfall of the electrical and thermal loads would be compensated by the AC grid and the backup boiler, respectively.

The CHP’s share of the electrical and thermal load was examined from the environmental/technical point of view, and the reduction of CO₂ emission due to the CHP installation was evaluated based on the CO₂ emission factor of the electricity grid.

From the economic point of view, the main parameters were the capital cost of the CHP unit, the electrical power price, and the natural gas price (grid). The analysis was able to specify the conditions under which the CHP installation would be economically feasible compared to existing energy facilities.

The time-step and lifetime of the simulation were set as one hour (60 min) and 10 years, respectively. The lifetime of all system components was assumed as the project lifetime (10 years), and the rate of interest was fixed at 0%.

8.5.2 Outputs from software analysis

Environmental/technical

Based on the hourly data of both the electrical and thermal loads (Figure 8.13), the HOMER simulation was carried out for 8760 (= 365 × 24) steps in one year. Figure 8.14 shows the share of CHP output for electrical load and thermal load over one year. Because the electrical demand was almost always higher than the rated power of the CHP (400 kW), the CHP operation time reached 8760 hours per year and the capacity factor was 97.3%. This corresponds to the fact that the CHP was operated continuously without stops through the year, which agrees well with the observed runtime data in Figure 8.6(b).

Figure 8.15 shows the monthly average share of CHP output over one year. Because the electrical load in summer was higher than that in other periods, the electrical share was relatively low in summer. As mentioned, since the capacity of heat supply was significantly higher than the thermal demand, the thermal share of the CHP was 100% and the backup boiler did not work.

Simulated yearly energy production and consumption of the CHP in The Octagon are summarized in Table 8.6. The simulated yearly production of electricity was calculated as 3,410,495 kWh and that for recovered heat was 1,025,283 kWh. As noted above, in 2012 the observed total electrical production was 3,381,004 kWh, and total recovered heat was 1,031,618 kWh. It can be stated that the simulation fairly agrees with the real operation of the CHP. Based on the assumed electrical load, the electrical share of the CHP was 54%, and the ratio of thermal utilization was 22%, which corresponds to the fact that 78% of produced heat was released from the cooling module as excess heat.

For the environmental aspect, the change of CO₂ emissions owing to the CHP installation was evaluated. The present calculation considered the CO₂ emissions from the grid electricity and natural gas used in The Octagon. Figure 8.16 shows CO₂ emissions from the site with and without CHP installation, and CO₂ emission reduction as a
function of the grid CO$_2$ emission factor. Because the grid CO$_2$ emission factor in NY is relatively low at 282 g/kWh (in 2010), as discussed in Section 8.3, the CO$_2$ emissions from energy use in The Octagon would be increased in the present simulation. The CO$_2$ emissions from the site would be increased by 433 ton/yr (866 kg/yr per unit) due to the CHP installation. If the average CO$_2$ emission factor in the US (559 g/kWh in 2010) were applied, the CO$_2$ emissions from the site would be decreased by about 500 ton/yr (1000 kg/yr per unit). As for the present case, a CO$_2$ emission factor of 400 g/kWh would be the threshold value for the reduction of CO$_2$ emissions.

Figure 8.14. Results of simulated hourly profile share of CHP output for (a) electrical load and (b) thermal energy load through one year.

Figure 8.15. Monthly average of simulated share of CHP output for (a) electrical load and (b) thermal energy load.
Table 8.6. Simulated yearly energy production and consumption at The Octagon with CHP installation.

<table>
<thead>
<tr>
<th></th>
<th>Electrical</th>
<th>Thermal</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Production</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Source</td>
<td>kWh/yr</td>
<td>%</td>
</tr>
<tr>
<td>Fuel Cell</td>
<td>3,410,495</td>
<td>54</td>
</tr>
<tr>
<td>Grid purchases</td>
<td>2,869,312</td>
<td>46</td>
</tr>
<tr>
<td>Total production</td>
<td>6,279,807</td>
<td>100</td>
</tr>
<tr>
<td><strong>Consumption</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Use</td>
<td>kWh/yr</td>
<td>%</td>
</tr>
<tr>
<td>AC primary load</td>
<td>6,279,807</td>
<td>100</td>
</tr>
<tr>
<td>Excess power</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Total consumption</td>
<td>6,279,807</td>
<td>100</td>
</tr>
</tbody>
</table>

Figure 8.16. CO\textsubscript{2} emission factor of grid vs. (a) CO\textsubscript{2} emissions from the site with and without CHP installation, and (b) CO\textsubscript{2} emission reduction.

Economic

Because the objective CHP system relies fully on the electricity and natural gas grids, as does the Japanese residential CHP, economic feasibility can be evaluated by the balance of the CHP capital cost and the reduction of operating cost owing to the CHP installation. Figure 8.17 shows a cash flow comparison over 10 years between the conventional case (CHP not installed) and the CHP-installed case. Installing the CHP would reduce yearly operating costs (grid electricity, natural gas, and CHP O&M costs) by $385,480 under the present NY grid costs of electricity and natural gas. Because the capital cost of the CHP is assumed as $3,000,000 in the present analysis, the present CHP installation can achieve payback within 10 years.

Figure 8.18 shows the optimal system diagram as functions of electricity price and natural gas price. It can be
reconfirmed that the CHP installation can be economically feasible under the present grid price at The Octagon. As shown in Figure 8.9, the national average electricity price in the US (ca. $0.12/kWh) is significantly lower than that in NY ($0.21/kWh), while the natural gas price for both is nearly the same ($0.36/Nm$^3$). If the US average prices of electricity and natural gas were applied to the diagram in Figure 8.18, the CHP installation would not be economically feasible.

Figure 8.17. 10-year cash flow comparison between (a) CHP not installed, and (b) CHP installed.

Figure 8.18. Sensitivity analysis results for optimal system as functions of electricity price ($/kWh) and natural gas price ($/m$^3$).
The simple payback time of the CHP installation at The Octagon was calculated as 7.78 years without incentives. The Octagon project received an award and a total of $1,200,000 in incentives from NYSERDA. These covered 40% of the capital (installation) cost of the CHP. Figure 8.19 shows the relationship between the capital cost multiplier and the simple payback time based on The Octagon simulation. Taking into account the incentives (capital multiplier = 0.6), the payback time would be less than five years.

![Figure 8.19. Relationship between CHP capital multiplier and simple payback time. A multiplier of 1 corresponds to $3,000,000.](image)

### 8.6 Summary

A 400-kW<sub>AC</sub> CHP system with PAFC was installed in a New York City apartment building called The Octagon. The CHP system relied on both the electricity and natural gas grids, as did the Japanese residential CHP. In this application, the electricity demand exceeded the rated power of the CHP (400 kW<sub>AC</sub>) almost all the time, and excess thermal energy was released via a cooling module. Therefore, based on the calculated results, the operation time of the CHP system reached 8760 hours per year and the capacity factor was 97.3%. Based on the assumed electrical load, the electrical share of the CHP was calculated as 54%, while the thermal share was 100%.

Based on the present grid cost in New York City, the CHP installation could bring an economic advantage for the users. The simple payback time was calculated as 7.78 years even when no incentives were considered.

On the other hand, based on the published CO<sub>2</sub> emission factor of the NY grid, the CHP installation would increase CO<sub>2</sub> emissions, because the CO<sub>2</sub> emission factor of the NY grid is very low at 280 g/kWh. When we assume
full operation of the CHP, a CO₂ emission factor of 400 g/kWh would be the critical value for the reduction of CO₂ emissions.

It can be expected that CO₂ emissions would be significantly decreased when the CHP operation follows the thermal load. However, operating with frequent starting and stopping and a small capacity factor is not appropriate for this large-scale CHP system.
9 FedEx forklift

9.1 Background [37,38]

Fuel cell vehicles (FCVs) are expected to provide significant positive environmental benefits; yet more time is required for their widespread adoption. However, hydrogen fuel cells are being used today in early market applications to satisfy commercial needs such as material handling equipment (MHE) and backup power. These early commercial fuel cell deployments are helping improve hydrogen and fuel cell technologies and expanding their market potential. In particular, fuel cell (FC)-powered forklifts are expected to achieve economic feasibility in the near future [37,38].

Forklifts are a type of material handling equipment (MHE) used by various industries to move materials to, through, and from production processes in receiving, storage, packing, and shipping. Fuel cell systems look particularly promising as replacements for forklift batteries in warehouses that operate two or three shifts per day. In such applications, batteries generally need to be charged and replaced one or more times each day, which complicates logistics and increases overall labor costs. FC-powered forklifts have zero emissions, can operate for more than 12 hours without performance degradation, and can be fueled in several minutes; these advantages make fuel cells an attractive alternative to conventional battery systems [38].

Forklift trucks are available in many variations and load capacities. They can be powered by batteries or internal combustion engines (ICEs) fueled by gasoline, propane, or diesel. The Industrial Truck Association (ITA) has defined seven classes of forklift trucks [37]:

- **Class 1** – battery-powered motor trucks with cushion or pneumatic (air-filled) tires
- **Class 2** – battery-powered motor narrow aisle trucks with solid tires
- **Class 3** – battery-powered hand trucks or hand-rider trucks with solid tires
- **Class 4** – ICE-powered sit-down rider forklifts with cushion tires, generally suitable for indoor use on hard surfaces
- **Class 5** – ICE-powered sit-down rider forklifts with pneumatic tires, typically used outdoors on rough surfaces or significant inclines
- **Class 6** – battery- or ICE-powered ride-on units with the ability to tow at least 1000 pounds; this class is designed to tow cargo rather than lift it
- **Class 7** – rough terrain forklift trucks with pneumatic tires; these are almost exclusively powered by diesel ICE and are used outdoors

Class 1, 2, and 3 forklifts are typically used in multi-shift operations by warehousing and distribution centers. Class 4, 5, and 6 trucks are typically used in construction, agriculture, manufacturing, and large warehousing. Battery-powered forklifts (Class 1, 2, and 3) are typically used in indoor material handling applications that do not require large lift capacities. Although new battery-powered forklifts can cost 20–40% more than ICE-powered trucks of a comparable size, battery-powered forklift trucks have lower lifecycle costs compared to ICE-powered models. This is due to lower maintenance costs, lower fueling costs, and a longer service life.
As noted by the NREL report [38], the US Department of Energy (DOE) has been funding deployments of fuel-cell MHEs in order to evaluate their performance, help further fuel cell technology- and manufacturing-readiness levels, and help build and expand early markets for fuel cell technologies. Leveraging funding from the American Recovery and Reinvestment Act (ARRA) of 2009, DOE helped fund deployments of PEM fuel-cell MHEs at eight commercial warehousing and distribution centers, including facilities operated by Sysco Houston, Sysco Philadelphia, HEB Grocers, Coca-Cola, Wegman’s Grocers, Whole Foods, Kimberly Clark, and FedEx Springfield. Additionally, the Department of Defense’s Defense Logistics Agency (DLA) concluded fuel cell research and development projects that have included multi-year demonstrations of the use of hydrogen fuel cell–powered forklifts in material handling operations at four of its warehousing and distribution centers. In total, more than 600 fuel-cell MHE units were deployed in eight commercial facilities and two government-operated warehouses.

9.2 **Outline of FedEx forklift project** [39]

With the assistance of the DOE, FedEx installed fuel cell power units (GenDrive®–class 1, Plug Power) into 35 existing forklifts at its freight distribution center in Springfield, MO (Figure 9.1) in June 2010. Battery power units in existing electric forklifts were replaced with FC power units (Figure 9.2(a)). Air Products installed hydrogen fueling and storage equipment (Figure 9.2(b)), and FedEx completed the system integration. A safety plan was completed by Plug Power, Air Products, and FedEx. The hydrogen fueling station was tested and became operational in June 2010. Start-up and training for forklift operators was finished in June 2010. Finally, the operation and evaluation of FC-powered forklifts were started in July 2010. Five FC power units were added in December 2010, bringing the total to 40 units, and eventually the entire forklift fleet at the site was converted to FC power. No DOE funding was used for the last five units.

Project overview is as follows [39]:

- **Duration:** October 2009 – September 2013
- **Total project funding:**
  - DOE: $1,290,646 (46%)
  - FedEx: $1,526,836 (54%)
- **Barriers:**
  - high number of repairs to fuel cells
  - operating fuel cells in cold weather
  - hydrogen fueling in cold weather
- **Partners:**
  - Plug Power: GenDrive® system and service provider
  - Air Products: Hydrogen supplier

The objectives of this project include [39]:

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To ensure safe and reliable operations of FC-powered MHE.
To demonstrate economic benefits of conversion.
To provide cost-effective and reliable hydrogen.
To establish a proving ground for FC-powered forklifts and to spur further forklift conversions.

Figure 9.1. Location of FedEx Springfield, MO [40].

Figure 9.2. Site photos at FedEx freight distribution center in Springfield, MO: (a) fuel cell power unit on a forklift, and (b) hydrogen dispensers [39].

9.3 System components and operation [39]

As mentioned Section 9.2, 35 FC-powered forklifts began operation at the FedEx freight center in July 2010, and five more were added in December 2010. Operation data is available up until February 2012 [39]. Figure 9.3 shows a comparison of fueling/charging systems for FC-powered and battery-powered forklifts. Because the battery power units in existing electric forklifts were replaced with FC power units, battery-powered forklifts were used as a base reference. The system components of the FC-powered systems are described below.
Fuel cell–powered forklift
At the time of this project, Plug Power provided three types of GenDrive® fuel cell power unit for forklifts: Class 1, Class 2, and Class 3. Of these, GenDrive Class 1 (Figure 9.4) had the largest lift capacity. Its specifications are as follows:

- nominal voltage: 36 V<sub>DC</sub>
- power output: 10–12 kW
- hydrogen storage: 2.2 kg
- storage pressure: 350 bar
- fill time: 3 min.
- lift capacity: 2260–4000 lb. (ca. 1000–1800 kg)

As shown in Figure 9.2(a), a fuel shield was installed to cover the fuel intake while the seat is down to prevent damage to the hydrogen hose.

Hydrogen fueling station
Air Products installed all hydrogen fueling and storage equipment, which included two indoor dispensers (Figure 9.2(b)) and a horizontal liquid hydrogen tank with a capacity of 6000 gallons (1600 kg). Air Products also provided hydrogen fueling training for operators, including operation, hydrogen safety, and emergency response. FedEx purchased more than 20,800 kg of hydrogen up to February 2012.

Operation results [39]
At the project outset FedEx was concerned that FC-powered forklifts would have a higher frequency of repairs compared to conventional battery- or ICE-powered forklifts. Other anticipated barriers included forklift operation and
hydrogen fueling in cold weather.

Figure 9.4 shows the distribution of mean time between repairs (MTBR) for the 40 FC power units from July 2010 to February 2012. The average MTBR for the power units was 261 hours. Figure 9.5 shows the distribution of repair times for the power units. The average repair time was about 2.0 hours. These repair data observed in Springfield (SGF) were compared to the data of conventional forklifts powered by ICE (propane fuel) at another FedEx freight center located in Whittier, CA (WHT). WHT had 42 propane forklifts with an average age of 7.1 years, while SGF had 40 FC forklifts with an average age of 7.5 years. The comparison was based on the data for unscheduled forklift repairs including FC repairs from July 2010 to February 2012. The average repair hours per forklift during that period was 144 hours at SGF and 64 hours at WHT. The repair time of FC forklifts was 2.25 times that of propane forklifts. It can therefore be said that the reliability of the FC power units was inferior to that of conventional ICE power units at that time.

The other issues of concern were the cold-weather operation and fueling of the FC-powered forklifts. Figure 9.6 shows the total number of repairs versus runtime of FC-powered forklifts. The figures show that repair frequency was high in the cold season (December 2010 to March 2011), when the average MTBR was about one-third of before that period. In order to reduce cold-weather operating problems, an additional heater was added to the power units, and the right side of Figure 9.6 shows the latest cold season data (up to February 2012). Average MTBR after March 2011 is clearly stable regardless of seasonal temperature change, although the effect of the additional heater is not clear. The hydrogen station was equipped with pneumatic valves, and hydrogen fueling problems in cold weather were solved by reducing the moisture content in the air supply in 2011.
9.4 SWOT analysis

A SWOT analysis was performed on the FedEx forklift project using published information [39]. The outcome of the analysis for each aspect of economic, environmental/technical, community/social, and regulatory is shown in Tables 9.1, 9.2, 9.3, and 9.4, respectively.
Table 9.1. SWOT analysis for FedEx forklift project — Economic aspect.

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demonstration of large-scale installation of fuel cell and fueling system</td>
<td>High cost of the system</td>
<td>Replace conventional propane forklift</td>
<td>Lack of cost merit</td>
</tr>
<tr>
<td>Quick charge (refuel time 3-6 min)</td>
<td>Increase of repairs under cold whether</td>
<td>Cost reduction owing to large-scale installation</td>
<td>Lack of maintenance support</td>
</tr>
<tr>
<td>Longer Mean Time Between Repair (MTBR) compared to conventional propane forklift</td>
<td></td>
<td>Global market for forklift application</td>
<td>Increased running costs due to higher fuel prices</td>
</tr>
<tr>
<td>Synergy effect of FC company (Plug Power) and hydrogen supply company (Air Products)</td>
<td></td>
<td></td>
<td>Poor fuel cell durability</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Installation in small sites is difficult due to high capital cost</td>
</tr>
</tbody>
</table>

Table 9.2. SWOT analysis for FedEx forklift project — Environmental/technical aspect.

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>Improvement of system efficiency and reliability</td>
<td>Lack of renewables</td>
<td>Potential to apply hydrogen power to forklift operation</td>
<td>High maintenance cost</td>
</tr>
<tr>
<td>Long time (accumulated over 74,300 hours) driving experience</td>
<td>Uncertainty of CO₂ reduction</td>
<td>Improvement of fuel cell reliability</td>
<td>Lack of CO₂ reduction</td>
</tr>
<tr>
<td>Evaluated operational and maintenance support for FC power unit</td>
<td>Difficulties of cold weather operation</td>
<td>Potential for installation of RES</td>
<td>Disaster owing to high-pressure (350 bar) hydrogen</td>
</tr>
<tr>
<td>Experience of FC operation in cold weather</td>
<td></td>
<td>On-site hydrogen supply for other applications</td>
<td></td>
</tr>
<tr>
<td>Cleaner environment</td>
<td></td>
<td>Potential for installation in other vehicles</td>
<td></td>
</tr>
</tbody>
</table>
9.5 Software analysis

9.5.1 Cost analysis by NREL [38]

The main objective of this analysis is to evaluate the economic feasibility of FC-powered forklifts relative to the ownership cost of conventional battery-powered forklifts. In April 2013, the National Renewable Energy Laboratory (NREL) of the United States published a technical report titled “An evaluation of the total cost of ownership of fuel
cell–powered material handling equipment” [38], which addresses the same objectives as the present study. The NREL analysis is quite comprehensive and instructive for the present study, and was based on data collected from the DOE and DOE-sponsored deployments of fuel-cell MHEs, including at FedEx Springfield. Because the present analysis uses some cost parameters determined by NREL, the outline of the NREL report should be introduced for better understanding.

The total cost of ownership analysis performed by NREL was based on two primary sources of data. Much of the data on MHE costs and usage came from a questionnaire provided to operations managers of the warehouses deploying fuel-cell MHEs (listed in Section 9.1). NREL sent questionnaires to facilities managers at 10 deployment sites and received responses from seven sites. Data on usage patterns were also drawn from NREL’s fuel-cell MHE composite data products (CDPs), which characterize fuel-cell MHE performance and operations. In addition to these primary sources of data, some literature data are referenced [38]. In the NREL analysis, all costs were presented as annualized costs on a per lift truck basis (in present value). Costs of ownership were not analyzed over a specific time period.

Based on the response to the questionnaire, NREL set each cost element of ownership for battery-powered and FC-powered forklifts (Classes 1 and 2). These cost elements include:

- cost of the bare forklift
- cost of the required battery or fuel cell system
- cost of battery changing and charging or hydrogen fueling infrastructure
- labor costs of battery changing or hydrogen fueling
- cost of energy required by the forklifts
- cost of facility space for infrastructure (indoor and outdoor)
- cost of lift truck maintenance
- cost of battery or fuel cell system maintenance

A summary of the cost elements contributing to the total cost of ownership of Class 1 and 2 MHEs is listed in Table 9.5 and illustrated in Figure 9.7. Some of the key input parameters affecting these costs are reviewed below.

**Table 9.5. NREL analysis results – Contributing costs to total annual ownership cost of MHE (Classes 1 and 2) [38].**

<table>
<thead>
<tr>
<th>Cost Element</th>
<th>Battery MHE</th>
<th>Fuel Cell MHE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Amortized Cost of Lift Truck</td>
<td>$2,800</td>
<td>$2,800</td>
</tr>
<tr>
<td>Amortized Cost of Battery / Fuel Cell Packs</td>
<td>$2,300</td>
<td>$2,600</td>
</tr>
<tr>
<td>Per-Lift Truck Cost of Charge/Fuel Infrastructure</td>
<td>$1,400</td>
<td>$3,700</td>
</tr>
<tr>
<td>Labor Cost for Charging and Fueling</td>
<td>$4,400</td>
<td>$800</td>
</tr>
<tr>
<td>Cost of Electricity / Hydrogen</td>
<td>$500</td>
<td>$2,400</td>
</tr>
<tr>
<td>Cost of Infrastructure Warehouse Space</td>
<td>$1,900</td>
<td>$500</td>
</tr>
<tr>
<td>Lift Truck Maintenance</td>
<td>$2,800</td>
<td>$2,800</td>
</tr>
<tr>
<td>Battery / Fuel Cell Maintenance</td>
<td>$3,600</td>
<td>$2,200</td>
</tr>
<tr>
<td>Total Annual Cost of Forklift</td>
<td>$19,700</td>
<td>$17,800</td>
</tr>
</tbody>
</table>
Cost of bare lift truck battery packs and FC systems

According to the feedback from the questionnaire, the average cost of a bare lift truck was $25,000 and average lifetime was 10 years. Based on this, the annualized present value cost of a bare lift truck (Class 1) was set at $2800.

Facility operators reported the average cost of a single battery pack as $4800, with an average lifetime of 4.4 years. The facilities operate two to three shifts per day, with an average of 2.25 shifts per day. Charging the MHE battery takes five to eight hours, plus a few hours of cooling time before the battery can be used. Due to this slow charging speed, users typically own one more than one battery pack per lift truck, and swap depleted batteries for charged batteries. Considering these data, the annualized present value of battery packs was fixed at $2300.

Operators reported an average cost of $33,000 for a fuel cell system for Class 1 and 2 lifts (typically 8–10 kW output). These equipment costs were generally offset by a federal tax credit available for FC systems, set at the lesser of $3000/kW or 30% of the cost. For an average system costing $33,000, this tax credit reduces the effective cost of the fuel cell system by about $10,000. Considering the cost reduction owing to the available tax credit and a lifetime of 10 years, the annualized present value of fuel cell systems per lift truck was set at $2600. If the tax credit were not available, the annualized cost of a fuel cell system would rise by $1100 to a total of $3700 per year per lift truck.

Cost of battery-charging and hydrogen-fueling infrastructure

Facility operators reported keeping an average of 1.1 chargers for each battery lift truck deployed. The average charger cost $2800, with an average lifetime of 7.5 years. Based on these data, the present-value annualized cost of chargers reported on a per-lift truck basis was $500. In addition to these equipment costs for battery chargers, battery infrastructure costs included the equipment costs for the racks, hoists, and cranes; periodic refurbishment of changing...
equipment; amortized construction costs for the battery changing and charging room; and maintenance of both the chargers and the battery changing equipment. These costs were estimated to be $900 per lift truck per year. Together with the equipment costs of the chargers, the total of present-value annualized battery infrastructure capital, operating, and maintenance costs was $1400 per lift truck.

Taking into account the number of fuel-cell MHEs served, the present-value annualized cost of hydrogen fueling infrastructure (including capital, operating, and maintenance costs) was $3700 per lift truck. It is important to note that this per-lift truck cost of hydrogen infrastructure was for an average fuel-cell MHE fleet size of 58 units. Per-lift truck hydrogen infrastructure costs vary inversely to the number of fuel cell units deployed.

Labor costs for battery-charging and hydrogen fueling

Based on the questionnaire, warehouse facilities operated an average of 333 days per year and averaged 2100 hours of operation per year. Facilities operated two or three shifts each day, with an average of 2.25 shifts per day. Facility managers reported an average loaded labor rate for battery change-out of $24/hour. Hydrogen fueling labor also averaged $24/hour.

Respondents reported an average of 2.25 battery changes per day, which corresponds to one battery change for each shift. Travel and queuing time for battery lifts averaged 3.8 minutes, and battery changes required an average of 10.5 minutes. Based on this, the annual per-lift truck labor cost for battery changing and charging was $4400.

Respondents reported an average travel and queuing time of 3.3 minutes for filling fuel-cell MHEs with hydrogen. Based on data from the deployments [38], actual hydrogen fueling time was 3 minutes per fill (compared to an average hydrogen filling time of 3.4 minutes reported by facility managers). Analyzing the data from the questionnaire and from the fuel-cell MHE deployments, the annual per-lift truck labor cost for hydrogen fueling was $800.

Cost of electricity and hydrogen

Based on feedback from warehouse operators, annual electricity costs per battery-powered lift averaged $500. As a reference, average commercial electricity rates in the US are about 7.5 cents/kWh. Facility operators reported an average hydrogen cost of $8/kg. Using fuel-cell MHE deployment data on per-lift truck hydrogen usage together with this average $8/kg hydrogen cost, fuel-cell MHEs incurred annual hydrogen expenses of $2400 per lift.

Cost of infrastructure space

The total cost of ownership analysis also considers the cost of warehouse space and outdoor space dedicated to hydrogen infrastructure and battery changing and charging infrastructure. Respondents did not address the cost of outdoor space, so the cost analysis used a value of $0.34/ft.²/month, which is the cost of leased land at fueling stations used by NREL’s Hydrogen Analysis (H2A) model.

Respondents reported an average of 5100 square feet of warehouse space dedicated to battery swapping and charging.
At an average warehouse cost of $3/ft.²/month, this resulted in an average annual warehouse space cost of $1900 per battery lift.

Warehouse space dedicated to hydrogen infrastructure (dispensers) averaged 500 square feet. Outdoor space dedicated to hydrogen infrastructure (storage equipment) averaged 2500 square feet, with a range of 500 to 5000 square feet. Applying the average costs of warehouse and outdoor space reported above results in an average annual infrastructure space cost of $500 per FC lift truck.

Cost of maintenance for lift trucks, battery packs, and fuel cell systems

Operators reported spending an average of $230 per month on bare lift truck maintenance, or $2800 per lift truck each year. This maintenance cost was assumed to be the same for battery lift trucks and fuel cell lift trucks. Operators reported an average of $150 per month in maintenance costs per battery system. With an average of two battery packs per lift, this resulted in an annual battery pack maintenance cost of $3600 per lift truck.

Based on data provided for the fuel-cell MHE deployments, maintenance time of fuel cell systems averaged about 1.5 hours per month. The analysis assumed a labor rate of $80/hour and that the total parts cost averaged half the maintenance labor cost. Based on this, the total annual maintenance cost for fuel cell systems was $2200 per lift truck. This calculated maintenance cost using deployment data matched the average $2200 annual per-lift truck maintenance cost reported in the questionnaire.

Total cost of ownership results

Figure 9.7 shows the results of the total cost of ownership assessment for both battery-powered and FC-powered Class 1 and 2 MHEs. The fuel-cell MHE deployments characterized in this cost analysis included an average of nearly 60 fuel-cell material handling units per site, with facilities operating two to three shifts per day. Under these conditions, fuel-cell MHEs are predicted to have a lower total cost of ownership than their comparable battery-powered counterparts. Overall, NREL concluded that for Class 1 and 2 forklifts used in multi-shift operations, fuel cells could reduce the overall cost of ownership by 10%, from $19,700 to $17,800 per year per lift truck.

9.5.2 Inputs for software analysis

System configuration and operation regime in HOMER

Because commercialization of FC-powered forklifts in a wide area of material handling has become of major interest, the main topic of the present analysis using HOMER is an evaluation of the economic feasibility of FC-powered forklifts relative to battery-powered forklifts. However, HOMER was designed to analyze stationary energy systems and has no options for vehicle applications analysis. Therefore, the present analysis considers forklifts as generators. The system configuration of forklift operation was the same as a stationary energy system consisting of generators and electrical load (primary load) in the HOMER platform (Figure 9.8). In the figure, “FC forklift” is a generator fueled by reformed hydrogen, and “Battery Forklift” is a generator fueled by natural gas. Adjusting efficiency and
fuel cost, simulation of power production by a generator was evaluated as operation (driving) of a forklift. “Primary load” was an electrical load in HOMER, which corresponded to the operation load of one forklift. “Reformer” was fueled by a type of natural gas different from the fuel of the battery forklift, and produced hydrogen. The reformer was considered to be hydrogen fueling equipment, disregarding its performance. The efficiency of the reformer was set at 30.5% so as to directly convert the price of a natural gas fueling reformer to the hydrogen price ($/m^3). (HOMER needs a specific hydrogen resource for a hydrogen-fueled generator, that is, electrolyzer or reformer.) Neither equipment nor loss related to hydrogen storage was considered in the present analysis.

![Diagram of system configuration](image)

**Figure 9.8.** System configuration of forklift operation in HOMER.

**Electrical (operation) load**

The actual operation of forklifts is complex, as the energy load varies greatly as the material is lifted and carried. Because profile data could not obtained, a virtual load profile was determined arbitrarily. Operation was assumed as 2400 hours per year. In the present analysis, as mentioned below, a constant efficiency regardless of load ratio was assumed for both the FC forklift and the battery forklift. Thus, only the total load influences the evaluation, and load profile was not significant. The FC forklift and the battery forklift both followed the same load in this case, and thus could be evaluated under the same load of operation.

In order to examine the effect of load size on the total cost of operation, several load scenarios with different load amounts were prepared. The yearly load amount was varied from 3 MWh to 5 MWh, although the load profile and operation time were constant.

**Assumed performance of forklift**

Based on the power output of the FC power units installed at FedEx Springfield, the nominal power of a single forklift was fixed at 12 kW for both the FC-powered and battery-powered lifts. Based on data provided by the FC
power unit supplier (Plug Power), the efficiency of the FC-powered forklift was set at 45% when pure hydrogen was fueled, which is assumed as constant regardless of load ratio. Argonne National Laboratory (ANL) reported that the typical charging efficiency of a battery charger is 84% and the typical discharge efficiency of batteries used in MHEs is 76% [41]. Because the battery forklift in the present HOMER simulation includes both charge and discharge functions, the efficiency of a battery-powered forklift was set at 63.8%, which is also assumed as constant and slightly higher than ANL’s estimate (63.8%).

Assumed performance of reformer
There is no information on the performance of reformers available at present, although Ramsden (NREL) reported that the average hydrogen cost of seven MHE facilities is $8/kg (ranging from $5 to $22/kg) [38]. Because the major interest of this study was economic issues, the analysis considered only the cost of hydrogen produced by the reformer. Based on the physical properties of natural gas in HOMER (energy content: 45 MJ/kg-LHV, density: 0.79 kg/m$^3$, carbon content: 67%), when the reformer efficiency was set at 30.5%, the volume of input gas (natural gas) was equal to that of output gas (hydrogen). In that case, the natural gas price ($/m^3$) could be used as the hydrogen price in an economic analysis.

Assumed cost
Much of the cost data for the forklift analysis was taken from the NREL report reviewed above [38]. In the case of battery-powered forklifts, all the cost data used here came from the NREL report. Because the present HOMER analysis did not consider any battery-charging apparatus, as shown in Figure 9.8, with the exception of electricity cost, the cost element classification used by NREL (Table 9.5) was summed up as capital cost or operating and maintenance (O&M). This conversion of cost elements is summarized in Table 9.6. The electricity cost was assumed as $0.08/kWh. Regarding the maintenance cost of the lift truck and battery, because HOMER requires O&M cost to be expressed per hour, the annualized cost calculated by NREL was divided by the yearly operation hours (2496 h) and applied to HOMER. The definition of labor cost for charging is described below.

As for the cost data of FC-powered forklift operation, in addition to the cost data published by NREL, the author also received inputs from the supplier of the FC power units (Plug Power). These inputs included the installation and O&M cost of hydrogen fueling equipment (infrastructure), which corresponds to “Per-Lift Truck of Fuel Infrastructure” in the NREL report. This cost of Plug Power was about 1.6 times higher than the cost reported by NREL. This could be mainly explained by the fact that the NREL analysis was based on 58 forklifts per site, while 40 forklifts were deployed at FedEx Springfield. In the present analysis, the cost data of hydrogen fueling equipment supplied by Plug Power was applied to the capital and O&M costs of the reformer in HOMER. In addition, the number of FC forklifts per hydrogen fueling infrastructure has been changed (i.e., Per-Lift Truck of Fuel Infrastructure has been changed) as listed in Table 9.7. A capital cost of the FC power unit assumed here was the same as that in the NREL report.
The literature [37,38] indicates that forklifts typically operate over multiple shifts per day. The shorter fueling time for fuel cells compared to the time required to swap and charge batteries gives FC forklifts an advantage over battery forklifts under these operating conditions. Therefore, the labor cost for charging/fueling was one of the critical parameters in an economic analysis of FC-powered forklifts compared with battery-powered forklifts. In the present analysis, the simulation was carried out under three different load conditions, in which the yearly total load of forklift operation was varied in 1-MWh/yr increments from 3 MWh/yr to 5 MWh/yr. Fuel (electricity or hydrogen) consumption under these different loads is listed in Table 9.8. An increase of the load brought an increase of fuel (electricity or hydrogen) consumption as well as an increase of charge/fueling frequency (Figure 9.10). Based on the NREL report, travel and queuing time of 3.8 min and battery charging time of 10.5 min were used to calculate labor cost for battery charging. As for FC-powered forklifts, travel and queuing time of 3.3 min and hydrogen fueling time of 3.4 min were used to calculate labor cost for hydrogen fueling. Because HOMER simulation needs a cost per hour for O&M, the labor cost for charge/fueling should be converted to the cost per hour. Based on the frequency and duration for charge/fueling, labor cost per 1 year was calculated and listed in Table 9.9. The cost for battery charging was significantly higher than that for hydrogen fueling.

Table 9.7. Assumed cost of hydrogen fueling infrastructure under different numbers of forklifts.

<table>
<thead>
<tr>
<th>Hydrogen fueling infrastructure</th>
<th>Initial cost</th>
<th>Operating &amp; maintenance (lease) cost</th>
<th>Cost of space in warehouse</th>
</tr>
</thead>
<tbody>
<tr>
<td>Per-Lift Truck cost of hydrogen fueling infrastructure</td>
<td>$200,000</td>
<td>$18,000/mo</td>
<td>$28,200/yr</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Number of deployed forklifts</th>
<th>Initial ($)</th>
<th>O&amp;M ($/yr)</th>
<th>Space ($/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>30</td>
<td>6667</td>
<td>7200</td>
<td>940</td>
</tr>
<tr>
<td>40</td>
<td>5000</td>
<td>5400</td>
<td>705</td>
</tr>
<tr>
<td>50</td>
<td>4000</td>
<td>4320</td>
<td>564</td>
</tr>
<tr>
<td>60</td>
<td>3333</td>
<td>3600</td>
<td>470</td>
</tr>
</tbody>
</table>
Scope of the analysis
In the present simulation of forklift operation, both FC-powered and battery-powered forklifts were operated under common loads. HOMER used a one-time installation cost as a capital cost of equipment. Because the project time in the simulation was set at 10 years, the capital cost in HOMER was calculated by multiplying the annualized capital cost (NREL data) by 10. Time-step was set as one hour (60 min). The lifetime of all system components was assumed
as the project lifetime (10 years), and the interest rate was fixed at 0%.

For the economic analysis, hydrogen cost was varied in the range from \$0.09/m^3 to \$0.90/m^3 (\$1–10/kg), while electricity cost was fixed at \$0.08/kWh. From the environmental/technological point of view, we should examine the technical performance of FC-powered forklifts, including such aspects as efficiency, durability, reliability, and safety. In particular, FC-powered forklifts provide a consistent level of power throughout their operation cycle, whereas battery-powered forklifts can sometimes exhibit a sag in their available voltage at the end of the discharge cycle, reducing available performance [38]. This might be a big advantage for FC-powered forklifts in real operation. In addition, use of FC-powered forklifts could reduce greenhouse gas emissions. However, because of lack of data, no analysis has been conducted of the environmental/technical aspect.

From the economic point of view, as mentioned above, the main parameters were the per-lift truck cost of hydrogen fueling infrastructure, the load for forklifts and the hydrogen price.

9.5.3 Outputs from software analysis

As the NREL report pointed out, the cost share of “Per-lift truck cost of hydrogen fueling infrastructure” should be large in the case of FC-powered forklifts (Fig. 9.7). This cost mainly depends on the number of deployed forklifts per site. As mentioned above, the NREL analysis was based on 58 forklifts per site, while 40 forklifts were deployed at FedEx Springfield. Therefore, at first, the relationship between the number of lifts and total cost was examined. Figure 9.11 represents the total operating cost comparison between the battery-powered and FC-powered forklifts (30 and 50 lifts). As this figure shows, “Per-lift truck cost of hydrogen fueling infrastructure” was strongly depends on the number of the lifts and the change of this cost affected definitely the total cost. When only 30 FC-powered forklifts were deployed in the site, the total cost per lift truck of FC forklifts would be higher than that of the battery-powered forklifts under the same load condition. Contrary to this, when the number of FC-powered forklifts was reached to 50 per site, the total cost of FC forklifts would be lower than that of the battery forklifts. Figure 9.12 shows economically optimal system diagrams comparing battery-powered and FC-powered forklifts under the constant load level (4MWh/yr). This diagram indicates that, when the number of forklifts was over 50 per site, FC-powered forklifts must be economically favorable rather than battery-powered forklifts regardless of hydrogen price. Consequently it can be stated that FC-powered forklifts should be deployed over 50 per site (i.e., fueling infrastructure) under typical cost of hydrogen fueling infrastructure (cf. Table 9.7).
Figure 9.11. Total cost elements of forklift under load of 4 MWh/yr and hydrogen price of $8/kg.

Figure 9.12. Optimal system diagram between battery-powered (black) and FC-powered forklift (dark blue) systems as functions of total cost of hydrogen fueling infrastructure and hydrogen price under loads of 4 MWh/yr. (When $H_2$ fueling infrastructure cost multiplier = 1, Initial = $6,667, and O&M=$7,200/yr, and space= $940/yr as listed in Table 9.7.)

The load level for the forklifts is also important parameter for the system evaluation. According to the load change, not only fuel (electricity or hydrogen) consumption but also labor cost of charge/fuel was changed, because frequency of charge/fueling depends on the load as show in Fig. 9.10. The cost elements under 3, 4, and 5 MWh/yr
are listed in Tables 9.10, 9.11, and 9.13, respectively, and the cost composition for each case is presented in Figures 9.13, 9.14, and 9.15, respectively, where hydrogen price was assumed as $8/kg ($0.72/m³). In the case of FC-powered forklifts, all the cost elements of other than “Per-Lift Truck Cost of Charge/Fuel Infrastructure”, “Labor Cost for Charging/Fueling”, and “Cost of Electricity/Hydrogen” were identical with the data of the NREL report [38]. As for battery-powered forklifts, “Labor Cost for Charging/Fueling” and “Cost of Electricity/Hydrogen” were different from the NREL data. As shown in these tables (9.10, 9.11, and 9.12) and figures (9.13, 9.14, and 9.15), the total cost of FC-powered forklifts was lower than that of battery-powered forklifts regardless of load level. Inspecting the NREL data again, it can be suggested that the NREL analysis described the cost comparison under 4 MWh/yr of load condition. Figure 9.16 presents the total cost of forklifts versus load level. The cost difference between battery-powered and FC-powered forklifts tends to increase as the load increase. This implies that the application FC-powered forklifts must be favorable into heavy load site rather than light load site.

Table 9.10. Annualized cost element per forklift under load of 3 MWh/yr and hydrogen price of $8/kg.

<table>
<thead>
<tr>
<th>Cost Element</th>
<th>Battery forklift</th>
<th>Fuel Cell forklift</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost of Lift Truck</td>
<td>$2,800</td>
<td>$2,800</td>
</tr>
<tr>
<td>Cost of Battery / Fuel Cell Packs</td>
<td>$2,300</td>
<td>$2,600</td>
</tr>
<tr>
<td>Per-Lift Truck Cost of Charge/Fuel Infrastructure</td>
<td>$1,400</td>
<td>$4,720</td>
</tr>
<tr>
<td>Labor Cost for Charging and Fueling</td>
<td>$3,282</td>
<td>$643</td>
</tr>
<tr>
<td>Cost of Electricity / Hydrogen</td>
<td>$1,400</td>
<td>$1,588</td>
</tr>
<tr>
<td>Cost of Infrastructure Warehouse Space</td>
<td>$1,900</td>
<td>$564</td>
</tr>
<tr>
<td>Lift Truck Maintenance</td>
<td>$2,800</td>
<td>$2,800</td>
</tr>
<tr>
<td>Battery / Fuel Cell Maintenance</td>
<td>$3,600</td>
<td>$2,200</td>
</tr>
<tr>
<td>Total Annual Cost of Forklift</td>
<td>$18,458</td>
<td>$17,915</td>
</tr>
</tbody>
</table>

Table 9.11. Annualized cost element per forklift under load of 4 MWh/yr and hydrogen price of $8/kg.

<table>
<thead>
<tr>
<th>Cost Element</th>
<th>Battery forklift</th>
<th>Fuel Cell forklift</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost of Lift Truck</td>
<td>$2,800</td>
<td>$2,800</td>
</tr>
<tr>
<td>Cost of Battery / Fuel Cell Packs</td>
<td>$2,300</td>
<td>$2,600</td>
</tr>
<tr>
<td>Per-Lift Truck Cost of Charge/Fuel Infrastructure</td>
<td>$1,400</td>
<td>$4,720</td>
</tr>
<tr>
<td>Labor Cost for Charging and Fueling</td>
<td>$4,376</td>
<td>$857</td>
</tr>
<tr>
<td>Cost of Electricity / Hydrogen</td>
<td>$501</td>
<td>$2,118</td>
</tr>
<tr>
<td>Cost of Infrastructure Warehouse Space</td>
<td>$1,900</td>
<td>$564</td>
</tr>
<tr>
<td>Lift Truck Maintenance</td>
<td>$2,800</td>
<td>$2,800</td>
</tr>
<tr>
<td>Battery / Fuel Cell Maintenance</td>
<td>$3,600</td>
<td>$2,200</td>
</tr>
<tr>
<td>Total Annual Cost of Forklift</td>
<td>$19,677</td>
<td>$18,659</td>
</tr>
</tbody>
</table>
Table 9.12. Annualized cost element per forklift under load of 5 MWh/yr and hydrogen price of $8/kg.

<table>
<thead>
<tr>
<th>Cost Element</th>
<th>Battery forklift</th>
<th>Fuel Cell forklift</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost of Lift Truck</td>
<td>$2,800</td>
<td>$2,800</td>
</tr>
<tr>
<td>Cost of Battery / Fuel Cell Packs</td>
<td>$2,300</td>
<td>$2,600</td>
</tr>
<tr>
<td>Per-Lift Truck Cost of Charge/Fuel Infrastructure</td>
<td>$1,400</td>
<td>$4,720</td>
</tr>
<tr>
<td>Labor Cost for Charging and Fueling</td>
<td>$5,470</td>
<td>$1,071</td>
</tr>
<tr>
<td>Cost of Electricity / Hydrogen</td>
<td>$627</td>
<td>$2,647</td>
</tr>
<tr>
<td>Cost of Infrastructure Warehouse Space</td>
<td>$1,900</td>
<td>$564</td>
</tr>
<tr>
<td>Lift Truck Maintenance</td>
<td>$2,800</td>
<td>$2,800</td>
</tr>
<tr>
<td>Battery / Fuel Cell Maintenance</td>
<td>$3,600</td>
<td>$2,200</td>
</tr>
<tr>
<td>Total Annual Cost of Forklift</td>
<td>$20,897</td>
<td>$19,402</td>
</tr>
</tbody>
</table>

Figure 9.13. Total cost elements of forklift under load of 3 MWh/yr and hydrogen price of $8/kg (50 lifts were deployed at the site.)

Figure 9.14. Total cost elements of forklift under load of 4 MWh/yr and hydrogen price of $8/kg (50 lifts were deployed at the site.)
9.6 Summary

In the case of FedEx Springfield, 40 FC-powered forklifts replaced battery-powered forklifts. From the technical point of view, FC-powered forklifts are generally sufficiently advanced. While detailed data on durability, stability, and safety remains insufficient, the report from FedEx suggests that FC-powered forklifts reached a technical level that would enable them to be used for extended periods under real operation loads.

The National Renewable Energy Laboratory (NREL) published a technical report that provided an economic evaluation of FC-powered forklifts in comparison to the ownership cost of conventional battery-powered forklifts.
Drawing on the NREL report, the present analysis also aimed to evaluate the economic feasibility of FC-powered forklifts for driving and carrying a common load. In particular, the present analysis focused on the number of FC-powered forklifts per one H\textsubscript{2} fueling infrastructure. Because the cost share of H\textsubscript{2} fueling infrastructure was very large, this number was substantial for total operation cost of FC-powered forklifts. The calculated results indicate that over 50 forklifts should be deployed at one H\textsubscript{2} fueling infrastructure. The present analysis also examined the difference between FC-powered and battery-powered forklifts in the frequency and time required for fueling/charging. Based on this examination on the fueling/charging, a software simulation was carried out under different loads of operation (driving and carrying). The calculated results indicate that FC-powered forklifts could achieve economic feasibility compared to battery-powered forklifts regardless of the load level, when over 50 forklifts was deployed at the site. Furthermore, it was revealed that the cost merit of FC-powered forklifts increased with the load increase. This implies thus that the application FC-powered forklifts must be favorable into heavy load site rather than light load site.
10 Hydrogen Office

10.1 Background [42]

The Scottish government’s target for renewable electricity generation is for renewables to generate the equivalent of 100% of gross annual consumption by 2020, with a new interim target of 50% by 2015. In 2012, the equivalent of 40.3% of gross electricity consumption was supplied by renewable sources, up from 36.2% in 2011 [43]. Figure 10.1 shows installed capacity of renewable electricity in Scotland. It can be seen that the capacity of wind turbine has grown significantly over the last 10 years. Because the instability and fluctuation of wind energy pose a burden for the electricity grid, energy-buffering technology is essential for further installation of renewables. Storing wind energy as hydrogen is one promising option for stabilizing the grid and reinforcing energy security.

Energy Park Fife is an ongoing project to develop a new business park in Fife, Scotland, that will be a world leader in the growth of the renewable energy market (Figure 10.2). The Energy Park is also ideally suited for a range of marine energy activities, particularly manufacturing, research and development, and operations and maintenance. For example, in the manufacturing site at Energy Park Fife, one company has fabricated sub-sea structures including jackets for offshore wind turbines. In addition, Methil Docks Business Park, which is part of Energy Park Fife, is a mixed-use development that includes offices, a child care facility, a bakery, vehicle repair and sales, and a football club. Recent development activity has seen the construction of the Hydrogen Office and two other office pavilion buildings. A wind turbine located on the dockside supplies electricity to the Hydrogen Office.

![Figure 10.1. Installed capacity of renewable electricity in Scotland, 2000 to Q3 of 2013 [43].](image-url)
10.2 Outline of the Hydrogen Office project [44]

The Hydrogen Office project was set up by Business Partnership Ltd. to support the accelerated development of the renewable, hydrogen, fuel cell, and energy storage industries. The goal is to inspire people; promote the opportunity; improve access to and understanding of the technology; promote sector development; facilitate research and development; and enhance educational opportunities.

The Hydrogen Office building was newly constructed in Fife at the Methil 3 Dock (Figures 10.3 and 10.4). At the start of the last century the area was a major coal mining and exporting area, and more recently it was a key location for the development of offshore oil and gas platforms. The Hydrogen Office project is seeking to develop a cluster of renewable, energy storage, and fuel cell activities that will see the area lead the transition from the old carbon-based fuels of the past, to the new low or zero carbon–based fuels of the future.

The hydrogen and fuel cell system was developed by the Shetlands-based Pure Energy Centre. A wind turbine (named “Poppy” by the pupils at the local school) generates electricity that powers all lights, computers, and coffee and tea machines in the Hydrogen Office building. Any surplus wind electricity is used to produce hydrogen from water. This hydrogen is stored in a tank and used by a fuel cell to produce electricity for the Hydrogen Office when there is insufficient wind or no wind at all. The only by-products of the fuel cell are heat and water, thereby providing a unique working environment for businesses to set up where a true clean, non-polluting, and green building is a reality.

A ground source heat pump (GSHP) has also been installed to supply heat to the offices. The GSHP operates using the power from both the wind turbine and fuel cell, providing the offices with heat during working hours.

Figure 10.5 illustrates the configuration of the office building and hydrogen system components. Formally
opened in early 2011 by the Scottish First Minister, the project has already started to achieve its aim of raising the visibility of the sector in Scotland, and is delighted to have been nominated and shortlisted as a finalist for the prestigious Scottish Green Energy Awards 2010 as one of the most innovative projects in Scotland.

Overview of the Hydrogen Office project is as follows:

Project title: The Hydrogen Office Project
Lead organization: The Hydrogen Office Ltd. (not-for-profit organization owned by the Business Partnership Ltd.)
Key words: Education, skill development, technology transfer, renewable energy, hydrogen, fuel cell, green transport, energy storage
Country: Scotland, United Kingdom
Town: Methil
Project time span: 2007 to 2011
Project budget: GBP 3.6 M
Funding sources: Scottish Enterprise, European Regional Development Fund, The Scottish Communities Renewable Household Initiative

Figure 10.3. Location of Hydrogen Office in Fife, Scotland.
Figure 10.4. Hydrogen Office building, hydrogen facilities (left), and wind turbine (“Poppy”).

Figure 10.5. Schematic overview of Hydrogen Office project [45].
10.3 System components and operation

Figure 10.6 illustrates the system configuration for the current study. The platform is composed of several subsystems that include the following in particular [44]:

- a wind turbine that supplies electricity to the office building, a hydrogen facility (electrolyzer), and AC grid
- an alkaline electrolyzer that generates gaseous hydrogen and oxygen using the surplus electricity
- a PEM fuel cell that provides electricity using the gas stored in the reservoirs to deliver electricity to the Hydrogen Office and the grid
- a pressurized hydrogen storage tank to store hydrogen produced by the electrolyzer
- a heat management system that ensures the storage and management of the heat produced by the system
- an electrical control system that ensures the conditioning of the electrical energy provided to the grid

![System configuration of the Hydrogen Office.](image)

The features of each component are described below. [44]

Wind turbine
A 750-kWp wind turbine supplied by Global Wind Power (GWP-750) was installed in Methil Dock (Figure 10.4). It has a hub height of 55 meters and a blade diameter of 47 meters. It is expected to produce around 1.3 million kWh/yr, 30 times the annual energy demand of the office.

Electrolyzer
An alkaline electrolyzer was installed in the flat building beside the office building. Nominal power consumption of the electrolyzer is 30 kW, which can produce 0.5 kg H₂/h at 12 bar. The produced hydrogen is purified to 99.95% purity.

Fuel cell
A proton exchange membrane fuel cell (PEMFC) system was installed in the same building as the electrolyzer. Nominal power output of the PEMFC stack system is 10 kW. The system is composed of two stacks of 50 cells each.

Hydrogen tank
A stainless steel tank stores hydrogen at up to 12 bar. Full capacity is about 11 kg H₂. A higher pressure storage tank is planned to be installed in anticipation of transport applications.

Heat pump (not illustrated in Figure 10.6)
A ground source heat pump (GSHP) was installed to supply heat to the offices. The GSHP operates using the power from both the wind turbine and fuel cell, providing the offices with heat during working hours.

AC demand
The output of the wind turbine is sold to the grid. The wind electricity is also sold over a small private wire network to three buildings in the business park: the Hydrogen Office, the Fife Renewables Innovation Centre, and the Methil Docks Boat Club (not illustrated in Figure 10.6). The project organizer (Pure Energy) reports that the business park as a whole has a maximum demand of around 80 kW. The Hydrogen Office building demand ranges from a few kW overnight to around 25 kW max during the day. The wind turbine is able to power the whole park 60–70% of the time. However, the detailed load profile could not be obtained at present.

Electrical control system (operation regime)
Table 10.1 and Figure 10.7 below show the basis of the control strategy for the system. This control strategy assumes the building load would be met at all times. The operation of the electrolyzer and fuel cell depends on both renewable generation (wind turbine output) and the state of charge (SOC) of hydrogen in the tank. The electrolyzer is switched on when the output of the wind turbine exceeds the demand and the hydrogen tank is not full. The fuel cell is switched on when the output of the wind turbine falls below the demand and the hydrogen tank is not empty. In real operation, the electrolyzer is switched on when the turbine is producing more than 80 kW over an average of 10 min, and the fuel cell is switched on when the turbine output is below an average of 10 kW for 10 min, based on this fundamental regime.

Cost
Based on Pure Energy’s response to a questionnaire, the cost of components in the Hydrogen Office is as follows:
• building: £1.1 million ($1.72 million)
• 750 kWp wind turbine: £1.57 million ($2.45 million)
• hydrogen system: £0.505 million ($0.789 million)
  o 10-kW PEM fuel cell: £116k ($181k)
  o 3-kW alkaline electrolyzer: £216k ($337k)
  o tank & piping: £105k ($164k)
  o fuel cell test center: £68k ($106k)
• grid electricity
  o purchase: £0.11/kWh ($0.172/kWh)
  o sellback: £0.055/kWh ($0.086/kWh)

Table 10.1. Control strategy of electrical control system [44].

<table>
<thead>
<tr>
<th>Renewable generation</th>
<th>H₂ storage level</th>
<th>Electrolyzer load</th>
<th>Fuel cell output</th>
<th>Grid export</th>
<th>Grid import</th>
</tr>
</thead>
<tbody>
<tr>
<td>&gt; Building load</td>
<td>Empty / partially filled</td>
<td>Powered by spare renewable supply</td>
<td>Off</td>
<td>Surplus renewable generation</td>
<td>None</td>
</tr>
<tr>
<td>&gt; Building load</td>
<td>Full</td>
<td>Off</td>
<td>Off</td>
<td>Surplus renewable generation</td>
<td>None</td>
</tr>
<tr>
<td>&lt; Building load</td>
<td>Empty</td>
<td>Off</td>
<td>Off</td>
<td>None</td>
<td>As required to meet load</td>
</tr>
<tr>
<td>&lt; Building load</td>
<td>Partially filled / Full</td>
<td>Off</td>
<td>Operate to meet load</td>
<td>None</td>
<td>As required to meet load</td>
</tr>
</tbody>
</table>

Figure 10.7. Control configuration [44].

10.4 SWOT analysis

SWOT analysis was performed on the Hydrogen Office project. The outcome of the analysis for each aspect of economic, environmental/technical, community/social, and regulatory is shown in Tables 10.2, 10.3, 10.4, and 10.5, respectively.
Table 10.2. SWOT analysis for Hydrogen Office project — Economic aspect.

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>Economic sustainability; all maintenance costs, operational costs and staff costs are paid through the wind generation income</td>
<td>High installation cost of the system</td>
<td>New business for green transport created</td>
<td></td>
</tr>
<tr>
<td>First wind hydrogen system in Scotland deployed in an urban environment for supplying businesses with continuous green power and back-up power</td>
<td>Hydrogen will be sold to heat a third-party building</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Free energy costs to the user of the building minus the maintenance costs</td>
<td>High maintenance cost (10-20k pounds per year)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Better working environment as there are no power shutdowns thanks to the hydrogen back-up supply</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 10.3. SWOT analysis for Hydrogen Office project — Environmental/technical aspect.

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>Built environment - building built to latest energy efficiency technologies. High efficiency of fuel cell and hydrogen boiler</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Zero emissions-hydrogen is produced by RES and building completely powered from wind and green hydrogen through fuel cell</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>To increase the uptake of RES and the sustainability of office environment, building is completely powered from green energy achieving more than 90% green power</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HAZOP, risk assessment and personnel training</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Over 95% plant availability over 2 years of continuous operation</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>


Table 10.4. SWOT analysis for Hydrogen Office project — Community aspect.

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>First wind/hydrogen system in Scotland deployed in an urban environment to completely power an office block using green energy and green hydrogen storage technology</td>
<td>New business for green transport created.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Deliver technical training for students</td>
<td></td>
<td>Hydrogen will be sold to heat a third-party building</td>
<td></td>
</tr>
<tr>
<td>University-level research such as MSc. Short courses on hydrogen and fuel cell technologies delivered.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Strong support from the local council, politicians, and First Minister.</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 10.5. SWOT analysis for Hydrogen Office project — Regulatory aspect.

<table>
<thead>
<tr>
<th>Strengths</th>
<th>Weaknesses</th>
<th>Opportunities</th>
<th>Threats</th>
</tr>
</thead>
<tbody>
<tr>
<td>National regulations for storage under negotiation</td>
<td></td>
<td></td>
<td>Lack of codes and standards</td>
</tr>
<tr>
<td>Feed-in tariff accepted</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HAZOP, risk assessment and personnel training</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

10.5  **Software analysis**

10.5.1  **Inputs for software analysis**

**System configuration in HOMER**

Figure 10.8 shows the system configuration of the Hydrogen Office in HOMER. In this platform, all the electrical components were connected to the AC grid. Wind power was preferentially supplied to the demand load (H2-Office
and surplus electricity was fed to the grid. Produced hydrogen from the electrolyzer was stored in the hydrogen tank, and the stored hydrogen was used by the fuel cell to generate power. As noted, a GSHP was also installed in the Hydrogen Office to supply heat to the offices. Because the heat demand and operation regime of the GSHP were not clear, the GSHP was not included in the present analysis, although it undoubtedly played an important role in supplying heat to the office.

![System configuration of the Hydrogen Office in HOMER.](image)

**Figure 10.8.** System configuration of the Hydrogen Office in HOMER.

**Wind power**

Dr. Daniel Aklil of Pure Energy provided the wind power output data observed at the site from 2011 to 2012. The data provides a comprehensive profile acquired every 10 min. HOMER calculated wind power using wind resource data (i.e., wind speed at respective time) and wind turbine properties such as rated power, power curve, turbine diameter, and hub height. This wind power data was converted to wind speed to produce the power curve shown in Figure 10.9. Using this wind speed and properties of the wind turbine, the wind power output was recalculated in HOMER. The difference between the original data and the recalculated data for yearly production of wind power was less than 5% even when the time-step was elongated from 10 to 60 min. The analysis in the present study was based on this recalculated wind power. Figure 10.10 shows the wind power profile through the year, and Figure 10.11 shows seasonal change of wind power. The wind power was relatively stable from September to February of the next year (not shown).
Figure 10.9. Assumed power curve of wind turbine.

Figure 10.10. Calculated wind power output through one year.
Assumed performance of the components

- Electrolyzer

Based on the specifications of the electrolyzer installed in the Hydrogen Office, the electrolyzer capacity was set at 0.63 kg/h with the power input at 30 kW\(_{AC}\). This corresponds to a constant efficiency of 82.7% (LHV). The minimum operation ratio was set at 30% relative to the nominal value. The electrolyzer was directly connected to the AC grid, and no loss related to rectifying (DC/AC conversion) was considered. Losses related to load following were not considered either.

- Fuel cell

The fuel cell power was set at 10 kW\(_{AC}\). As shown in Figure 10.12, the efficiency at the rated operation was assumed as 50% (LHV) including DC/AC conversion, when the hydrogen consumption was about 0.6 kg/h. The minimum load ratio was set at 30% of the nominal value. The thermal energy utilization was not considered.

- Hydrogen tank

The capacity of the hydrogen tank was set at 10 kg, which was slightly less than the capacity of the installed tank (11 kg). The tank was assumed
to be empty at the beginning of operation. No loss related to hydrogen storage and transport was considered.

**AC load**

The Hydrogen Office is located in the Energy Park Fife business park, and three buildings in the business park — the Hydrogen Office, Fife Renewables Innovation Centre, and Methil Docks Boat Club — are electrically connected with each other via a small private wire network. The wind electricity is sold to these three buildings over this network. Based on these conditions, the present analysis used two load profiles: the load of the whole park (three buildings) (“load 1”), and the load for the Hydrogen Office (“load 2”). Both load 1 and load 2 were derived from the default load profile in HOMER, and thus both have a common profile, when each load was fitted to the respective load levels. The load properties of load 1 and load 2 are shown in Figures 10.13 and 10.14, respectively. The maximum load for load 1 was about 80 kW and yearly total demand was about 201 MWh. For load 2, the maximum load was about 25 kW and yearly total demand was about 67 MWh. Because both loads were based on the same profile, random variability in day-to-day and time-step to time-step was common.

![Figure 10.13. Properties of load 1 (maximum demand ca. 80 kW).](image-url)
Operation scheme

In a real operation, as mentioned above, the electrolyzer is switched on when the turbine is producing more than 80 kW over an average of 10 min, and the fuel cell is switched on when the turbine output is below an average of 10 kW for 10 min. However, it was difficult to simulate the system operation under this control regime in HOMER. Therefore, in the present analysis, the system was operated with the simple operation regime shown in Table 10.1. The electrolyzer was switched on when the wind power exceeded the demand and the hydrogen tank was not full, while the fuel cell was switched on when the demand exceeded the wind power and the hydrogen tank was not empty. In addition to that regime, in order to assure that fuel cell output could compensate the demand in peak time, FC operation was restricted to 0700 to 2000 through the year, as shown in Figure 10.15.

Scope of the analysis

The Hydrogen Office project was funded by the public sector, as noted in Section 10.2. In particular, the installation cost of the system components was fully supported by a grant. Based on preliminary calculations using the cost

Figure 10.14. Properties of load 2 (maximum demand ca. 25 kW).

Figure 10.15. Operation schedule of PEMFC in the Hydrogen Office.
information noted in Section 10.3, it was determined that the present hydrogen system is not economically feasible even when sellback electricity is considered. Therefore, the present analysis focused only on the technical aspect of the hydrogen system. Using the above-mentioned operation regime, the fuel cell’s share of demand was evaluated under different two load levels. In addition, the hydrogen state of charge (SOC) in the tank was analyzed. Finally, the effect of the wind turbine installation was reviewed from the point of view of environmental/technical and economic aspects.

As for wind power output, the present analysis used a recalculated profile with time-step of 60 min. The time-step of system simulation was also 60 min. Project time was set at 25 years and annual real interest rate was set at 0%.

10.5.2  Outputs from the software analysis

Based on the hourly data of wind power and load profile, the HOMER simulation was carried out for 8760 (= 365 × 24) steps for a year. Figure 10.16 shows examples of the simulated power profile of demand (load 1), wind turbine output, electrolyzer input, and fuel cell (FC) output in one day (4 July). As expected, the electrolyzer and FC operation depended on the power balance of the wind power and the demand: The FC was switched on in the morning when demand exceeded the wind power, and it was switched off at 1300 and the electrolyzer was switched on when the wind power rapidly increased and exceeded the demand. The electrolyzer was switched off at 2000 when the hydrogen tank was full. However, examination of the calculated results for a whole year revealed that operation of the electrolyzer and FC overlapped during about 15–25% of the FC’s total operation time. During this overlap time, the electrolyzer was partially powered by the FC output, which was a fault of the simulation. However, it is difficult to remove this overlap time at present. Hence, the electrolyzer operation (i.e., hydrogen production) was overestimated in the present simulation.

Figure 10.16. Hourly profile of power in one day (4 July).
Figure 10.17 shows a summary of the simulated hydrogen system operation under load 1 (80 kWp), which corresponds to the load of the whole business park. The wind turbine produces about 1.073 million kWh per year, which is in good agreement with observed data although slightly lower than the expected value (1.3 million kWh/yr). Wind power supplied 73.0% of the total load (i.e., AC load + electrolyzer load). Because the size of the hydrogen system components was relatively small compared with that of the wind power, the contribution of the hydrogen system was limited, and 83.8% of the electricity produced by the wind turbine was sold to the grid. The FC output accounted for 9.9% of the AC load.

Tables 10.6 and 10.7 show the operation summaries of the fuel cell and the electrolyzer with load 1, respectively. The FC operated for 39.5% of the restricted yearly operating time (4775 h). The FC started up an average of once per day over the period. Because the operating hours of the FC were restricted, it could be operated at its rated power of 10 kW almost all the time; thus the efficiency was kept high. Operating hours of the electrolyzer were nearly the same as for the FC. The typical pattern of operation was that during morning hours the FC operated and hydrogen SOC decreased, and the rest of the time the electrolyzer operated to charge if wind power was surplus to the load.

Figure 10.18 shows the hourly change of hydrogen SOC in the tank through the year and a frequency histogram of the SOC level. Because the wind power output definitely exceeded to the demand of the hydrogen system components, the hydrogen tank was frequently full. To examine the effect of tank size, the system operation was simulated with tank sizes ranging from 5 kg to 100 kg, while the specifications of other components were constant. Figure 10.19 shows the calculated results with changing tank sizes. Operation hours and hydrogen production of the electrolyzer increased linearly with the tank size, while those of FC were stable. The Hydrogen Office project initially planned to include on-site hydrogen fueling equipment for hydrogen vehicles; this analysis suggests that the present system has the potential to supply larger amounts of hydrogen if the tank size is enlarged.

### Electrical production

<table>
<thead>
<tr>
<th>Production</th>
<th>kWh/yr</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind turbine</td>
<td>1,073,041</td>
<td>92</td>
</tr>
<tr>
<td>Fuel cell</td>
<td>18,858</td>
<td>2</td>
</tr>
<tr>
<td>Grid purchases</td>
<td>71,377</td>
<td>6</td>
</tr>
<tr>
<td>Total</td>
<td>1,163,277</td>
<td>100</td>
</tr>
</tbody>
</table>

### Electrical consumption

<table>
<thead>
<tr>
<th>Consumption</th>
<th>kWh/yr</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>AC load</td>
<td>210,239</td>
<td>18</td>
</tr>
<tr>
<td>Electrolyzer load</td>
<td>54,289</td>
<td>5</td>
</tr>
<tr>
<td>Grid sales</td>
<td>898,749</td>
<td>77</td>
</tr>
<tr>
<td>Total</td>
<td>1,163,277</td>
<td>100</td>
</tr>
</tbody>
</table>

Figure 10.17. Summary of system simulation results under load 1.
Table 10.6. Fuel cell operation under load 1.

<table>
<thead>
<tr>
<th>Quantity</th>
<th>Value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hours of operation</td>
<td>1,886</td>
<td>hr/yr</td>
</tr>
<tr>
<td>Number of starts</td>
<td>405</td>
<td>starts/yr</td>
</tr>
<tr>
<td>Capacity factor</td>
<td>7.95</td>
<td>%</td>
</tr>
<tr>
<td>Electrical production</td>
<td>18,858</td>
<td>kWh/yr</td>
</tr>
<tr>
<td>Mean electrical output</td>
<td>10.0</td>
<td>kW</td>
</tr>
<tr>
<td>Hydrogen consumption</td>
<td>1,131</td>
<td>kg/yr</td>
</tr>
<tr>
<td>Mean electrical efficiency</td>
<td>50.0</td>
<td>%</td>
</tr>
</tbody>
</table>

Table 10.7. Electrolyzer operation under load 1.

<table>
<thead>
<tr>
<th>Quantity</th>
<th>Value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hours of operation</td>
<td>2,017</td>
<td>hr/yr</td>
</tr>
<tr>
<td>Mean input</td>
<td>6.2</td>
<td>kW</td>
</tr>
<tr>
<td>Total input energy</td>
<td>54,289</td>
<td>kWh/yr</td>
</tr>
<tr>
<td>Capacity factor</td>
<td>20.7</td>
<td>%</td>
</tr>
<tr>
<td>Total production</td>
<td>1,138</td>
<td>kg/yr</td>
</tr>
<tr>
<td>Specific consumption</td>
<td>47.7</td>
<td>kWh/kg</td>
</tr>
<tr>
<td>Mean conversion efficiency</td>
<td>69.9</td>
<td>%</td>
</tr>
</tbody>
</table>

Figure 10.18. Calculated SOC of hydrogen tank for one year under load 1: (a) stored hydrogen profile for one year (0–8760 h, 60-min step), and (b) frequency histogram.

Figure 10.19. Hydrogen tank capacity vs. (a) operating hours, and (b) yearly hydrogen production of electrolyzer and consumed by FC.
Figure 10.20 shows a summary of the hydrogen system operation under load 2 (25 kWp), which corresponds to the demand of the office building only. The wind power output was the same as with load 1. Wind power accounted for 84.8% of the total load (i.e., AC load + electrolyzer load), and 93.0% of wind power was sold to the grid. The FC output accounted for 19.1% of the AC load, which was significantly higher than was the case with load 1.

Tables 10.8 and 10.9 respectively show the operation summary of the fuel cell and the electrolyzer with load 2. Operation times of both with load 2 were lower than with load 1. The FC operated for 26.7% of the restricted yearly operating time (4775 h). As was the case for load 1, the operating hours of the electrolyzer were nearly the same as those of the FC. This can be explained by the fact that the rates of hydrogen production and consumption were nearly the same under load 2. Nevertheless, the frequency of the tank reaching full state was over 65% (Figure 10.21), while with load 1 it was 55% (Figure 10.18).

![Figure 10.20. Summary of system simulation results under load 2.](image)

**Table 10.8. Fuel cell operation under load 2.**

<table>
<thead>
<tr>
<th>Quantity</th>
<th>Value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hours of operation</td>
<td>1,274</td>
<td>hr/yr</td>
</tr>
<tr>
<td>Number of starts</td>
<td>329</td>
<td>starts/yr</td>
</tr>
<tr>
<td>Capacity factor</td>
<td>14.5</td>
<td>%</td>
</tr>
<tr>
<td>Electrical production</td>
<td>12,740</td>
<td>kWh/yr</td>
</tr>
<tr>
<td>Mean electrical output</td>
<td>10.0</td>
<td>kW</td>
</tr>
<tr>
<td>Hydrogen consumption</td>
<td>764</td>
<td>kg/yr</td>
</tr>
<tr>
<td>Mean electrical efficiency</td>
<td>50.0</td>
<td>%</td>
</tr>
</tbody>
</table>

**Table 10.9. Electrolyzer operation under load 2.**

<table>
<thead>
<tr>
<th>Quantity</th>
<th>Value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hours of operation</td>
<td>1,383</td>
<td>hr/yr</td>
</tr>
<tr>
<td>Mean input</td>
<td>4.21</td>
<td>kW</td>
</tr>
<tr>
<td>Total input energy</td>
<td>36,849</td>
<td>kWh/yr</td>
</tr>
<tr>
<td>Capacity factor</td>
<td>14.0</td>
<td>%</td>
</tr>
<tr>
<td>Total production</td>
<td>773</td>
<td>kg/yr</td>
</tr>
<tr>
<td>Specific consumption</td>
<td>47.7</td>
<td>kWh/kg</td>
</tr>
<tr>
<td>Mean conversion efficiency</td>
<td>69.9</td>
<td>%</td>
</tr>
</tbody>
</table>
As mentioned above, it is not possible for the hydrogen system to achieve economic feasibility with current installation costs. Instead of that, an economic analysis of the wind power installation was performed under load 1 without considering the hydrogen components (FC, electrolyzer, and tank). Project time of the analysis was 25 years. Figure 10.22 presents a 25-year cash flow comparison between the base case (grid only) and the case of grid plus wind turbine. The economic parameters of this comparison are listed in Table 10.10. Annual worth and simple payback time of the wind turbine installation were calculated as $5679 and 23.6 years, respectively. The project organizer reported that the payback time of the wind turbine is estimated at around 14 years. The reason for this difference is not clear at present. However, the project organizer reported that the Hydrogen Office is eligible for Renewables Obligation Scotland (ROC). Thus, there is a possibility of receiving an additional incentive, although details are not clear. The CO₂ reduction with load 1 due to wind turbine installation was estimated as 3830 kg/yr, when the CO₂ emission rate of the Scottish grid is assumed as 289 g/kWh [43].
10.6 Summary

The Hydrogen Office project was set up to support the accelerated development of the renewable, hydrogen, fuel cell, and energy storage industries. The goal is to inspire people; promote the opportunity; improve access to and understanding of the technology; promote sector development; facilitate research and development; and enhance educational opportunities.

Because the size of the hydrogen system components at this site (electrolyzer, storage, and fuel cell) was relatively small compared with wind power (750 kWAC), the contribution of the hydrogen system was limited. This means that the bulk of wind power output (>80%) was supplied directly to the grid. Based on Pure Energy’s response to our questionnaire, in view of the intermittent power input from the wind turbine, the technical reliability of the electrolyzer was critical for system operation. In addition, according to the project manager, the quality of grid power (particularly voltage) was also critical, and the role of the voltage controller in the hydrogen system was very important.

Because of the current high cost of hydrogen components, it was difficult to evaluate the economic advantage or payback time. Annual worth and simple payback time were calculated as $5679 and 23.6 years, respectively, even
when only the wind turbine installation was considered.

The Hydrogen Office has acted as a good base for hydrogen technology deployment in Scotland. It has shown the possibility for energy storage technologies such as hydrogen to increase Scotland’s capability to more fully harness its vast renewable energy resources, offering significant long-term employment and carbon reduction benefits.
11 Model concept for each category

This chapter presents a model concept for each community of rural/island, urban, and industrial/commercial, based on the case studies documented in chapters 5–10. While each project was unique even in its own community, the proposed models should be considered as examples for the respective communities.

11.1 Rural/island communities

Background
There are some rural/island communities in which RES exceed local demand, even though the local AC grid capacity is typically small. Among the wide variety of RESs, hydro, geothermal, and biomass offer relatively stable or controllable power output, although installation is not easy. Installation of wind and PV power, on the other hand, is relatively easy, but the fluctuations of available time are relatively large, and unstable voltage and frequency might harm the grid. It is possible that an unstable RES could exceed the limit of the grid capacity and its output be rejected by the grid controller. In this study, we have addressed a hydrogen storage system in which the excess power of RES is converted to hydrogen, which is stored and converted to power on demand. This system can contribute to grid stabilization, and, as a result, enables the introduction of larger amounts of RES to the community. Consequently, the hydrogen storage system is expected to help construct a robust and green community.

General features
Water electrolysis is the most realistic method of producing hydrogen using the power from RESs such as wind and PV. There are two main options in electrolysis: alkaline and proton exchange membrane (PEM) electrolysis. The alkaline electrolyzer is conventional and cost-effective, while the PEM electrolyzer is rather expensive but offers excellent performance. Produced hydrogen is stored in storage equipment located beside the electrolyzer. There are also several options for hydrogen storage, including pressurized, metal hydride, and liquefied. Among these, pressurized hydrogen in a tank is the most typical stationary application. In this case, hydrogen pressure is typically in the range from 10 to 50 bar. Stored hydrogen is used as a fuel for fuel cells to generate power on demand. There are also several options in fuel cells: proton exchange membrane fuel cell (PEMFC), phosphoric acid fuel cell (PAFC), molten carbonate fuel cell (MCFC), and solid oxide fuel cell (SOFC). Because PEMFC has the lowest operating temperature among these, it is easy to handle and has excellent start/stop characteristics. If the hydrogen storage capacity is significantly large, it may be possible to supply hydrogen to FC-powered vehicles (FCVs) via a hydrogen dispenser. In that case, the hydrogen must be pressurized to over 350 or 700 barg.

Model concept
In the present study, considering a small-scale AC grid in a rural/island community that includes unstable RESs such
as wind and PV, the model concept of the hydrogen system that plays the role of peak shaving and the peak shift was prepared as shown in Figure 11.1. The scale of the hydrogen system depends on the needs of each community. In this model, all the RESs are connected to the local AC grid, and hydrogen is produced by the electrolyzer using this grid power. The produced hydrogen is stored in the hydrogen storage tank beside the electrolyzer. Two major options for hydrogen utilization methods are presented here: one is delivering hydrogen to each consumer site via pipelines, as in the Lolland project, and the other is power production using a fuel cell adjacent to the hydrogen storage tank, as at Myrte. In the former case, the delivered hydrogen is used as a fuel by a CHP using a fuel cell that produces heat and power simultaneously. The operation of the CHP should follow the thermal load of the consumer, because large-scale heat storage is difficult. In order to achieve higher operation hours of the CHP, the system should have the capability to feed the surplus electricity back to the grid. In this case, hydrogen is consumed according to the demand of each consumer, and it is unclear whether the system operation can contribute to grid stabilization. Because buildings are widely separated in rural areas, construction of a hydrogen pipeline becomes significantly expensive. In the latter case, grid stabilization would be the main role, because fuel cell operation can be controlled according to the balance between the demand and supply of the grid. This function is the same as a smart grid using secondary batteries and power control units. The concept and technology in smart grid development would be also useful for the present application.

Figure 11.1. Schematic concept of rural/island model.
**Strength/weakness**

One of the most important challenges of this system is to be able to present an example of a robust green community by adding the capability of storing the energy produced by an RES using hydrogen. In addition, from the viewpoint of energy security and local development, local production of energy for local consumption should be promoted extensively.

On the other hand, it is considerably difficult to achieve economic feasibility of a hydrogen system in a rural/island community. In addition, there are difficulties in moving heavy equipment and maintenance in remote rural areas. In some communities, codes and standards do not exist or are inadequate, and accordingly it has taken a long time to obtain the permission of the authorities for the installation.

**Final remarks**

In view of the various environments of energy conditions in rural/island communities, there may be cases where this model concept is unsuitable. In general, the electric power is suitable as a main energy career for communities. It would be useful to obtain the views of those involved in the development of smart grids. It is difficult to evaluate the effect of grid stabilization quantitatively at present. Because it is difficult to achieve economic feasibility with this system, the social value put on promoting a green community becomes the determining factor for installation.

**11.2 Urban applications**

**Background**

In urban communities RESs account for a relatively low share of demand and grid capacity, and thus the motivation for installing hydrogen systems is limited. However, the reduction of CO$_2$ emissions from urban areas is a rather important problem, and because both the electric power and gas grids are generally already in place, the efficient utilization of these energies is the most realistic solution for this problem. It is also possible that both energy costs and CO$_2$ emissions can be reduced by the introduction of small-scale cogeneration plants at each consumer site. Fuel cells are highly efficient at converting energy from hydrogen to electricity, and natural gas reforming technology has progressed significantly recently. Therefore, CHP systems using FCs are becoming an attractive option for small-scale cogeneration plants in urban communities.

**General features**

There are several options for fuel cells that can be used with CHPs (i.e., stationary application). The physical and chemical properties of the electrolyte in the cell determine the operating temperature. Major FC candidates with their typical operating temperatures are as follows:

- polymer electrolyte (proton exchange membrane) fuel cell (PEFC, PEMFC) [60–80°C]
- phosphoric acid fuel cell (PAFC) [150–200°C]
• molten carbonate fuel cell (MCFC) [500–700°C]
• solid oxide fuel cell (SOFC) [700–1000°C]

These FCs have been commercialized already in many countries. In general, FCs with higher operating temperatures have higher efficiency at rated operation and higher tolerance to impurities contained in the hydrogen fuel, although their start-up performance is inferior. Conversely, FCs with lower operating temperatures have excellent start-up and load-following performance. Natural gas is the most popular form of fuel because of its well-organized infrastructure and ease of handling and reforming. Operation regimes depend on consumer need and are described below. Nevertheless, it is difficult to store a large amount of heat on-site, so the handling of the heat output becomes a crucial factor. The thermal load following operation must be appropriate for small consumers such as detached houses.

Economic feasibility depends on the relation between the grid cost (electricity and fuel) and CHP cost (installation and O&M). As for grid cost, the higher cost of electricity and lower cost of CHP fuel (natural gas) are advantages for CHP introduction. If an RES is not used, we need to consider carefully whether CHP operation would reduce CO₂ emissions: the typical fuel of a CHP is a hydrocarbon and CO₂ emissions therefore cannot be avoided.

Model concept
The urban model proposed here relies fully on the electricity and natural gas grids, as shown in Figure 11.2. No RES is considered here as the main component in the system, although many complex systems for RES and the grid are in use even in urban communities. In addition, because the main energy carriers are electricity and natural gas, this system should not be called a hydrogen system in the strict sense. Although the only customers shown in Figure 11.2 are apartment buildings and detached houses, the CHP can be also used in a commercial building. In this model, natural gas supplied via the grid is the fuel of the CHP, and it is reformed to hydrogen at each site. Reformed hydrogen is typically supplied directly to the fuel cell without storage. The FC produces heat and power simultaneously in response to consumer demand. There are several options for CHP operation regime:

1) operation following both thermal load and electrical load, with all the outputs consumed at the site
2) operation following only the thermal load, and the surplus output of electricity is fed back to the grid
3) operation following only the electricity load, and the surplus output of heat is released to atmosphere
4) operation at the rated power, and the surplus electricity is fed back to the grid and the surplus heat is released to atmosphere

The operating ratios (i.e., capacity factor) of the CHP under these regimes can be placed in order of magnitude as 4 ≫ 3 ≫ 2 ≫ 1. The selection of operation regime depends on the CHP’s technical specifications (scale, start/stop characteristics), the economy, the regulatory environment, and so on.
Strengths/weaknesses
The advantage of this system is that only a minimal initial investment is required, because it uses existing energy infrastructure. In general, FC technology is already mature, and the main challenge is reducing the cost of installation. In the case study in New York City, the natural gas grid was well organized and the gas price was comparatively low compared to the relatively high cost of electricity. In this case, it is possible that the consumer can realize an economic benefit within 10 years by installing a CHP with FC.

On the other hand, the reduction of CO$_2$ emissions as a result of the CHP installation is not obvious but depends on the CO$_2$ emission factor of the local grid. The simulation in the case study suggested that installing a CHP at The Octagon would cause an increase of CO$_2$ emissions. We also need to consider the purity of natural gas used with PEFC, which is sensitive to impurities in the fuel and would be degraded immediately.

Remarks
As described above, there are several types of fuel cell suitable for use in CHP systems. For a small-scale CHP application of up to several kW, load-following operation and frequent start and stop are typical, and PEFC is most suitable. If the CHP is to be operated at rated power for long periods, other types of FC (PAFC, MCFC, and SOFC) might be a better choice.

11.3 Industrial/commercial applications

Background
The present study focused on small-scale hydrogen application in an industrial/commercial community, although

Figure 11.2. Schematic concept of urban model.
hydrogen has been massively used in specific industrial sectors such as ironworks and oil refineries. Based on the results of a survey conducted under subtask 2, hydrogen systems are being used today to satisfy needs in specific commercial applications such as forklifts, backup power, and cogeneration in commercial buildings. The main objective of these applications is the reduction of energy costs and CO$_2$ emissions.

**Model concept**

Hydrogen system applications in industrial/commercial communities take various forms, and defining a model concept is virtually impossible. Figure 11.3 summarizes several examples of hydrogen system applications. In the industrial/commercial sector, hydrogen is supplied in various ways, including electrolysis, reforming, and delivery, and it is stored in a tank. If wind and PV are to be deployed, they should be connected to the AC grid. In the case of cogeneration applications for commercial buildings, hydrogen is supplied to an FC-based CHP at the site. The aim and function of this application are the same as those of CHP applications in urban communities. For forklifts, hydrogen must be pressurized to over 350 bar for dispensing, and it must be over 700 bar for other FC-powered vehicles such as buses and car. However, a full-scale hydrogen station is beyond the parameters of the small-scale distributed system assumed for analysis in this Task.

![Diagram of industrial/commercial model](image)

**Figure 11.2.** Schematic concept of industrial/commercial model.

**Strength/weakness**

The typical competitors for FC-powered vehicles such as forklifts are battery-powered ones. In this contest, a lower
charging frequency (longer driving distance per charge) and shorter charging (fueling) time are major advantages for FC-powered vehicles. In addition, FC-powered vehicles provide a constant level of power between fuelings, while battery-powered vehicles can sometimes exhibit a sag in their available voltage at the end of their discharge cycle, reducing available performance. This is a significant practical advantage for FC-powered vehicles.

Reduction of the hydrogen price is challenging. The US DOE target delivery price for hydrogen for vehicles is about $5/kg. Based on our case study, this target price would be also appropriate for forklifts. However, if an RES is a power source for hydrogen production by electrolysis, it will be difficult to bring costs down to meet this target. Another unresolved matter is the still-high cost of installing hydrogen dispensers.

Remarks
In industrial/commercial communities, fuel cell and hydrogen systems currently are being used commercially in early market applications such as forklifts and backup power. These early commercial fuel cell deployments are helping improve hydrogen and fuel cell technologies and expanding their market potential.
12 Conclusions

This final report of subtask 3 of Task 29: DISCO-H2 contains case studies of six selected projects and proposals for concept models for rural/island, urban, and industrial/commercial communities. All six projects reviewed here have been planned carefully and operated vigorously.

SWOT analysis reveals that a lack of codes and standards for installation and operation of hydrogen-related facilities has been a crucial problem for developers and consumers, particularly in rural/island and urban communities.

Thanks to the kind assistance provided by the respondents from each project, our case studies produced many findings, particularly in the environmental/technical and economic aspects. Some CHP applications in urban communities are close to achieving economic feasibility. FC-powered forklifts are also promising under certain load conditions in warehouses. Conversely, it is considerably difficult to attain commercial autonomy of RES-based hydrogen storage systems, and their main role is currently nothing but demonstration. A questionnaire titled “Project Follow-Up Questions” was prepared and delivered to each project respondent, focusing mainly on the community/social and regulatory aspects. Unfortunately we received only a few replies, and these aspects have not been sufficiently explored.

The author has assumed that readers are not only researchers in hydrogen-related fields but also policymakers or ordinary people who have a keen interest in the construction of “green communities”. Almost all distributed hydrogen system projects have been introduced with official subsidies or incentives. Public awareness and consensus are absolutely imperative for inclusion of “green” hydrogen in distributed and community energy systems. The author hopes this report will help to build understanding of the state-of-the-art achievements in the field of distributed hydrogen systems.
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