Energy in Buildings and Communities Programme

Impact of Support Mechanisms on Microgeneration Performance in OECD Countries

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October 2014

A Report of Annex 54 “Integration of Micro-Generation and Related Energy Technologies in Buildings”

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On behalf of IEA EBC Annex 54

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Adam Hawkes (Subtask C Leader), Evgueniy Entchev, Peter Tzscheutschler (Operating Agents)

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1 Introduction

1.1 Motivations and aims

Microgeneration technologies are generally recognized as important part of the energy system, and may play a significant role in meeting national and international energy policy targets for the buildings sector. However, as they are usually capital-intensive technologies, financial support mechanisms appear to be necessary in order to encourage their early adoption.

As shown in [1], a range of support schemes can be adopted, such as grants, feed-in tariffs, trading mechanisms and tax reductions. The present report analyses of the impact of different support mechanisms based on case studies developed by Annex 54 participants. Each mechanism can influence energy and economic performance as well as incentivise new operating strategies and applications to maximise investor benefits

Since results depend on several parameters that are specific to the cases/countries analysed (such as, for instance, energy loads and tariffs) the present work does not strive to identify common criteria to compare across support mechanisms. Instead it makes an overview of the effects of different approaches on microgeneration performance and operation, and presents a range of outcomes based on the support mechanisms observed over the life of the Annex.

Most of the cases discussed in the present report have been developed for the Subtask B activity in Annex 54, whose one of the main goal is providing an extensive library of performance assessment studies for microgeneration technologies. Since the present work mainly focuses on the effect of country incentives on energy system performances and operation, for a more complete explanation of the modelling tools and methodology adopted to develop the analysis, the reader should refer to the complete country-specific study in Subtask B.

The applications described in the following deal with micro-combined heat and power (CHP), larger CHP, and technologies fuelled by natural gas and hybrid renewable energy systems, made up of a micro-CHP unit and a renewable device (i.e. PV, GSHP), the combination of which provides an increase in energy savings in addition to a continuous energy supply.

It is worthy of note that some of the analysis that will be discussed below have been conducted with the help of a specific tool developed by the University of Munich in collaboration with Università del Sannio and Imperial College London, for which a short guide can be found in the Appendix.

1.1 Deliverables of Subtask C

The deliverables of Subtask C in respect to the Annex 54 proposal are:

- review and discuss policy support instruments for microgeneration adopted by some OECD countries (i.e. UK, Germany, Italy, Flanders, The Netherlands, Canada, Japan and Korea);

- assess the influence of support mechanisms on energy and economic performance of micro-CHP and microgeneration technologies on the basis of country specific analysis;

1.2 Contents of this report

The following topics are covered in the sections of this report:

- Individual country analyses of microgeneration operating with the support of a mechanism in Section 2.
- A summary of country-specific analyses, presented in Section 3.
- Details of the analysis tool applied several studies and the summary in Appendix A.

2 Country-specific analysis

The section presents an overview of the effects of country specific support mechanism on microgeneration performances, through studies conducted by Annex 54 participants. All the case studies reported below are organised as follows:

i. a brief introduction to describe the specific application and technologies considered in the analysis, together with the national support schemes available at the time of writing,
ii. assessment of the main performance parameters of the microgeneration application without considering support schemes,
iii. effect of the policy mechanisms on microgeneration system performance, and finally
iv. a brief discussion.

As noted in report 1 of Subtask C, the nature of financial mechanisms that support microgeneration can change frequently. Therefore the reader should refer to primary sources to obtain the latest information in this regard. The following section simply presents the influence of instruments existing at the time of writing on and financial and energy/environmental case for microgeneration.

2.1 United Kingdom

Introduction

The study assesses the effect of UK policy support schemes on the introduction of micro-CHP devices in a single-family dwelling.

Fig. 1 and 3 show, respectively, the average hourly thermal and electrical load of a dwelling for six typical days, which have been assumed to be representative of the entire year. Data have been measured using a 5-minute interval step (Fig. 2, 4), from which the thermal and electrical peak demands of respectively 30kW$_{th}$ and 3.7kW$_{e}$can be observed.

A 1 kW$_{e}$ ICE (main technical and economic parameters are reported in Table 1) has been considered. A heat-led strategy has been assumed, and operating strategy where switching the system on is only possible when recovery of all the thermal power produced by the unit is achievable. Thus, the unit is switched off in 'summer periods', resulting in 5,385 operating hours per year.

The assessment of energy, environmental and economic performances of the microgeneration system requires comparison with separate energy production, defined as the 'reference scenario', where the thermal demand is satisfied by a conventional boiler and the electricity is bought from the grid.

The main techno-economic parameters of the microgeneration installation under analysis, together with the characteristics of the reference scenario are reported in Table 1.

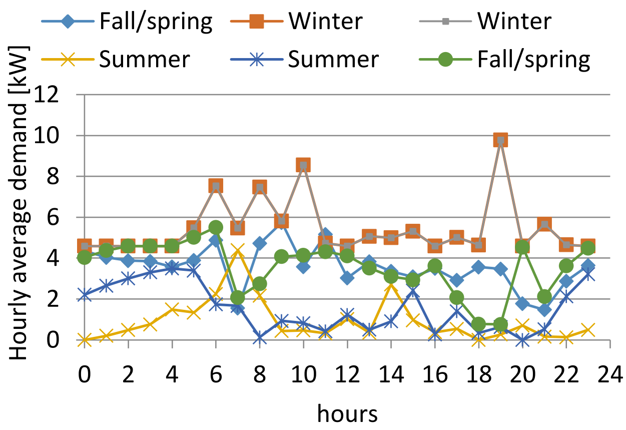


Fig.1 Hourly average thermal loads.

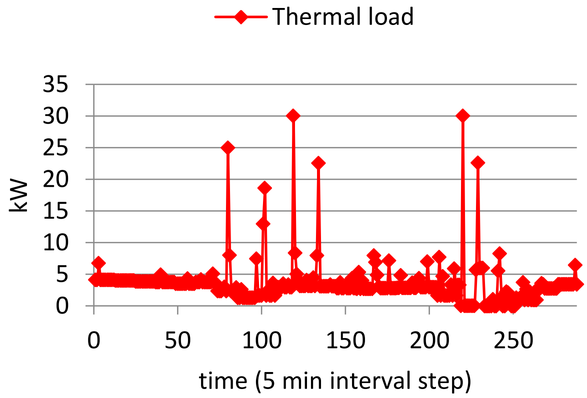


Fig.2 Time series measurement of thermal loads.

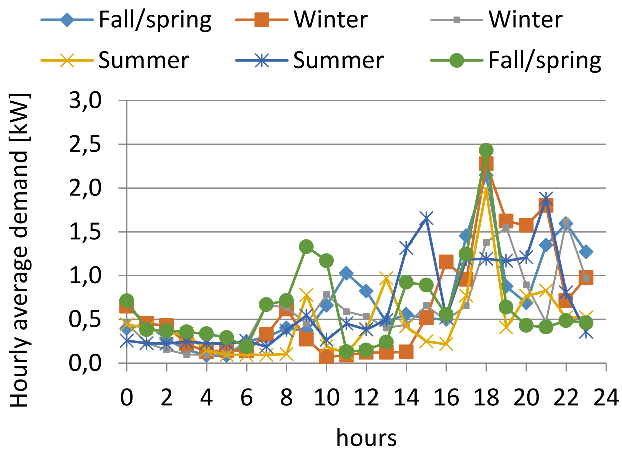


Fig.3 Hourly average electrical loads.

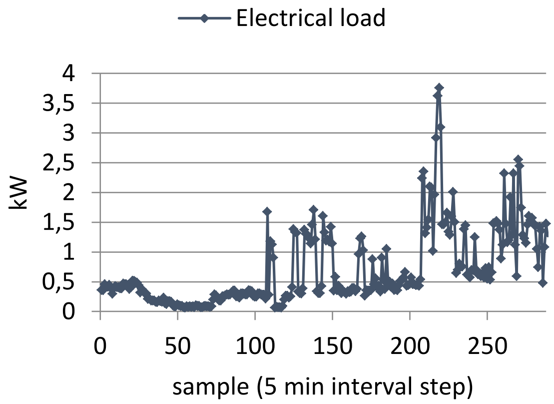


Fig.4 Time series measurement of electrical loads.

Table 1. Techno-economic parameters of micro-CHP installation and reference scenario.

MICROGENERATION INSTALLATION	
MICRO-CHP UNIT [2]	
Manufacturer	Honda MCHP1.OK1
Power output [kW_e]	1
Thermal output [kW_{th}]	2.8
Thermal input [kW_{th}]	4.4
Electrical efficiency	22.5%
Capital cost [£]	3,500
ADDITIONAL HEATING BOILER	
Capacity of the additional heating boiler [kW]	30
Thermal efficiency of the boiler	90%
Capital cost [£/kW]	1700
REFERENCE SCENARIO	
Capacity of the heating boiler [kW]	30
Thermal efficiency of the boiler	90%
Capital cost [£/kW]	1,700

With regards to supporting schemes currently available in UK, as discussed in [1] a micro-CHP unit with an electrical output lower than 2kW$_e$ can take advantage of the feed-in tariff scheme. Each eligible generator receives a FiT of 0.129 £/kWh for all the electrical energy produced by the system and a reward for the exported energy fixed at 4.64 pence/kWh.

Baseline Performance Assessment (No Incentives)

The present paragraph shows the main performance parameters of the micro-CHP device without considering any incentives. The analysis has been conducted with the "Economic micro-CHP assessment tool" attached to the present report (see Appendix).

Table 2 reports the technical and economic parameters used in the analysis.

Table 2. Techno-economic parameters used in the study.

Parameter	Value
PE factor for electricity [kWh_PE/kWh]	2.50
PE factor for NG [kWh_PE/kWh]	1.10
CO_2 factor for NG [g/kWh] [3]	235.00
CO_2 factor for electricity [g/kWh] [4]	520.00
Electricity purchasing price [c£/kWh] [5]	14.27
Feed in tariff to grid [c£/kWh] [6]	4.64
NG price* [c£/kWh] [5]	5.10
Feed in premium tariff [c£/kWh] [6]	12.90

* referred to the Low Calorific Value

Working in thermal priority mode, the system is able to satisfy the 54% of the thermal demand, and 59% of electrical demand, while the 46% of the electricity produced by the micro-CHP unit is exported to the grid.

It is worth noting (Table 2) that the feed in tariff to grid is lower than the electricity purchasing price, reinforcing the importance of consuming all the electricity produced by the ICE onsite in order to maximize the economic benefits.[1]

Results, reported in Table 3 show that the yearly total cost of the micro-CHP installation (given by the sum of capital, maintenance, gas and electricity cost) is higher than separate production, due to the incidence of investment cost. Considering revenues deriving from the electricity exported to the grid, the micro-CHP installation provides a slight economic advantage of 2%, while a 8% reduction in operating costs and a 12% reduction in primary energy consumption and CO_2 emissions can be achieved. The SPB has been calculated as a ratio between the extra costs of the micro-CHP installation and savings in the energy bill.

[1] Revenues coming from the avoided cost for not buying the electricity from the grid are, indeed, higher than revenues coming from the electricity sold to the grid.

Table 3. Results without incentives.

	Microgeneration	Reference scenario	Δ
Total cost [£/y]	3,130	3,056	2%
Saldo [£/y] (cost-revenues)	3,002	3,056	-2%
Operating costs [£/y]	2,696	2,935	-8%
PE [MWh_PE/y]	45	51	-12%
CO_2 [tCO_2/y]	9	11	-12%
CO_2 abatement costs [£/t]	49		
PE abatement costs [£/MWh]	11		
SPB [years]	Longer than lifetime[2]		

Fig. 5 shows a comparison between CO_2 emission savings of the microgeneration and reference system highlighting the contribution of electricity and gas consumption.

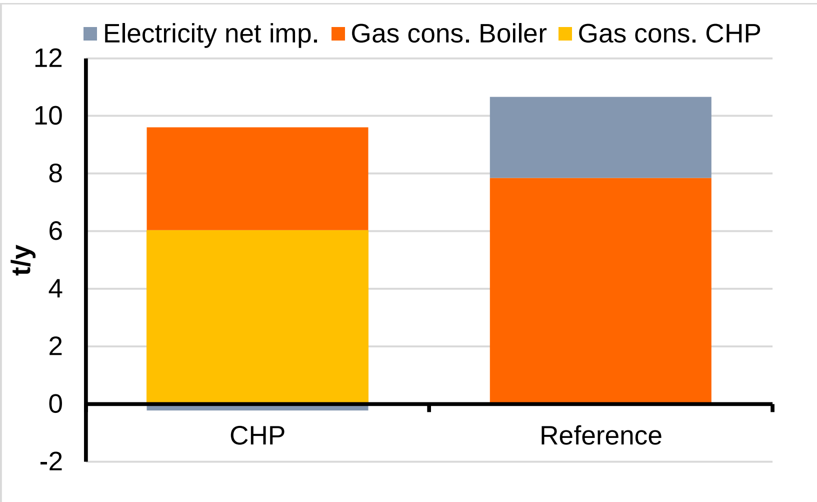


Fig.5 CO_2 emission savings derived from micro-CHP technology.

Performance assessment with support mechanism

As discussed above, a feed-in tariff mechanism is available for micro-CHP systems with a power output lower than 2kW$_e$. The value of the feed-in tariff was 0.129 £/kWh at the time of writing. In this case, the revenues increase by £752 with a consequent yearly savings of 27% compared to the

[2] A lifetime of 50,000 hours has been assumed

reference case. Operating costs with and without incentives are the same, since there is no reduction in energy carriers tariff. Overall, the SPB is reduced from 20 to 5 years, making the investment attractive for rational investors, all other factors being equal.

Table 4. Results with incentives.

	Microgeneration	Reference scenario	Δ
Total cost [£/y]	3,130	3,056	2%
Saldo [£/y] (Cost – revenues)	2,225	3,056	-27%
Operating cost [£/y]	2,696	2,935	-8%
PE [MWh_PE/y]	45	51	-12%
CO_2 [tCO_2/y]	9	11	-12%
SPB	5		

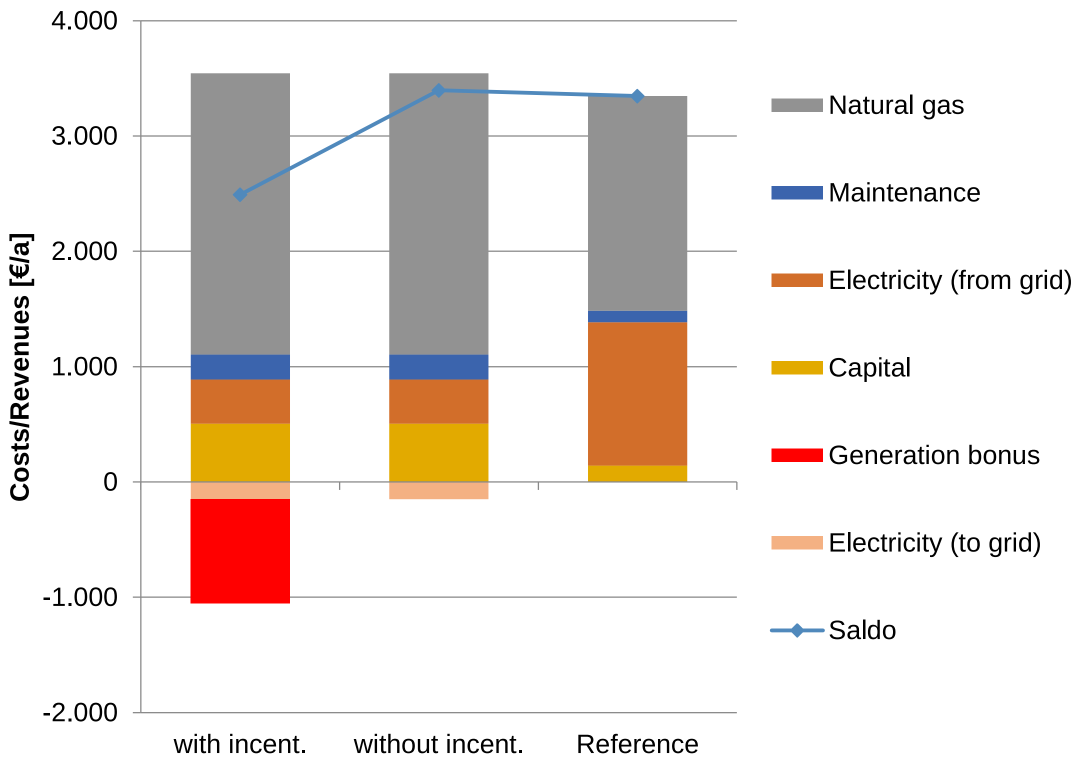


Fig.6 Comparison between the micro-CHP case with and without incentives and the reference case, in the UK.

Discussion

The impact of the UK FiT scheme on microgeneration economic performance in a single-family dwelling has been assessed. An ICE unit of 1kW_e has been considered, showing that without incentives, there is a slight economic cost (2%) for the introduction of a micro-CHP system, while a 12% reduction in CO_2 and primary energy consumption can be achieved.

But where revenues from the FiT scheme are included, the investment becomes significantly more attractive and the SPB period shortens from 20 to 5 years. Clearly this is an attractive proposition for a rational investor with unfettered access to capital.

2.2 Germany

Introduction

The present case study assesses the influence of German support schemes on the introduction of a Stirling engine device in a single-detached house.

Energy loads come from a measurement campaign conducted on four single-family dwellings in Southern Bavaria, equipped with a Stirling micro-cogeneration system and a buffer storage tank. Calculations refer to one of the four installations for which an annual thermal and electrical demand of, respectively, 40,538 kWh and 6,088 kWh has been measured.

Table 5. Techno-economic parameters of micro-CHP installation and reference scenario.

MICROGENERATION INSTALLATION	
MICRO-CHP UNIT	
Technology	Stirling
Power output [kW_e]	1
Thermal output [kW_{th}]	5
Fuel input [kW_{th}]	6.7
Total efficiency	90%
Capital cost (including the auxiliary burner cost) [€]	14,000
ADDITIONAL HEATING BOILER	
Additional heating boiler capacity[kW]	20
Thermal efficiency [%]	90%
REFERENCE SCENARIO	
Heating boiler capacity [kW]	20
Thermal efficiency [%]	90%
Capital cost [€]	5,000

The main characteristics of the microgeneration installation and reference scenario are reported in Table 5. An auxiliary boiler of 20 kW_{th} capacity is integrated into the CHP unit to satisfy the peak load and in case of maintenance, a heat-led strategy has been followed in order to maximize the primary energy consumption of the unit. The micro CHP installations have been monitored over a period of three years, collecting all relevant energy related parameters, such as: temperature, flow rates, gas consumption, electricity consumption and generation.

With regards to German supporting scheme, as discussed in [1], any eligible microgeneration installation can take advantage of:

- priority for the electricity produced and fed to the grid;
- generation premium for all the electricity produced by the micro-CHP device ranging from 1.8 to 5.41€ct/kWh;
- tax refund of 0.55 €ct for each kWh of natural gas feeding the micro-CHP unit;
- a grant, ranging from 1.500 to 3450 €, which is provided for micro-CHP with a power output lower than $20kW_e$.

Baseline Performance Assessment

The baseline performance assessment evaluates the introduction of the Stirling engine unit without considering incentives. The profitability is evaluated with respect to separate energy production, also defined as reference scenario, as in the previous case.

The reference scenario is characterised by a 20 kW_{th} heating boiler with an efficiency of 90%. Table 6 shows the main technical and economic parameters used in the study.

Table 6. Techno-economic parameters used in the study.

	Parameter
PE factor for electricity [kWh_PE/kWh]	2.6
PE factor for NG [kWh_PE/kWh]	1.1
CO_2 factor for NG [g/kWh]	235
CO_2 factor for electricity [g/kWh]	580
Grant for 1kWe micro-CHP device [€]	1,500
Electricity purchasing price [c€/kWh]	27.0
Feed in tariff to grid [c€/kWh]	4.5
NG price [c€/kWh]	5.3
NG tax rebate [c€/kWh]	0.55
Generation premium for electricity from micro-CHP [c€/kWh]	5.41

Simulation results show that the micro CHP unit covers the 64% of the thermal demand and the 56% of the yearly electricity demand. Since the Stirling engine operates in heat led mode, periods occur when the excess electricity produced must be fed into the grid. As such, only 65% of CHP electricity generation is consumed on-site.

Without incentives, excess electricity has to be fed into the grid at a very low price (4.5 c€/kWh), generating small revenues. Considering the yearly total cost, the equipment (capital and maintenance costs) is 30% of total, and consumption of natural gas and electricity accounts for 70% of the total expenditure.

In the reference case equipment accounts for 13%, and 87% is attributed to the energy carriers. In total, the micro CHP system is not profitable compared to separate energy production without any support mechanisms (see Table 7) although a 10% reduction in primary energy consumption can be achieved.

Table 7. Results without incentives.

	Microgeneration	Reference scenario	Δ
Total cost [€/y]	4,883	4,633	5%
Saldo [€/y] (cost-revenues)	4,803	4,633	4%
Operating costs [€/y]	3,668	4,281	-14%
PE [MWh_PE/y]	59.7	66.7	-10%
CO_2 [tCO_2/y]	12.5	14.1	-12%
CO_2 abatement costs [€/t]	102.5		
PE abatement costs [€/t]	24.3		
SPB [years]	/		

Taking into account CO_2 as the most prominent greenhouse-gas, the house equipped with micro CHP system has 12% lower CO_2-footprint than a building with separate production. If only heat and electricity provided by the micro-CHP is taken into account, the CO_2-emission reduction reaches 17%. The abatement costs of about 100 € per ton of CO_2 are very high compared to the current CO_2 market prices of 3 to 4 €/t.

Performance assessment with support mechanism

Table 8 shows the impact of German support schemes on the profitability of the micro-CHP system. With regards to the economic performance assessment, capital and gas costs decreases by about 10% leading to an overall reduction in costs of 8%. Simultaneously the revenues increase by the factor of four due to the generation bonus. In total, the support mechanism analysed here reduces yearly costs for heating and electricity of the building by about 13%. Compared to a conventional system the micro-CHP system saves about 10%.

Table 8. Results with incentives.

	Microgeneration	Reference scenario	Δ
Total cost [€/y]	4,563	4,633	-2%
Saldo [€/y] (Cost – revenues)	4,201	4,633	-9%
Operating cost [€/y]	3,477	4,281	-19%
PE [MWh_PE/y]	59.7	66.7	-10%
CO_2 [tCO_2/y]	12.5	14.1	-12%
SPB	11		

Discussion

Fig. 7 and 8 show key results of the energy, environmental and economic assessment of a $1kW_{el}$ micro CHP system integrated into a single-family dwelling.

Compared to an installation with a standard boiler and electricity purchased from the grid as reference, the micro CHP system is only 4% more expensive at the time of writing. In aggregate, the combination of support mechanisms reduces costs by about 13%, providing an attractive SPB of 11 years.

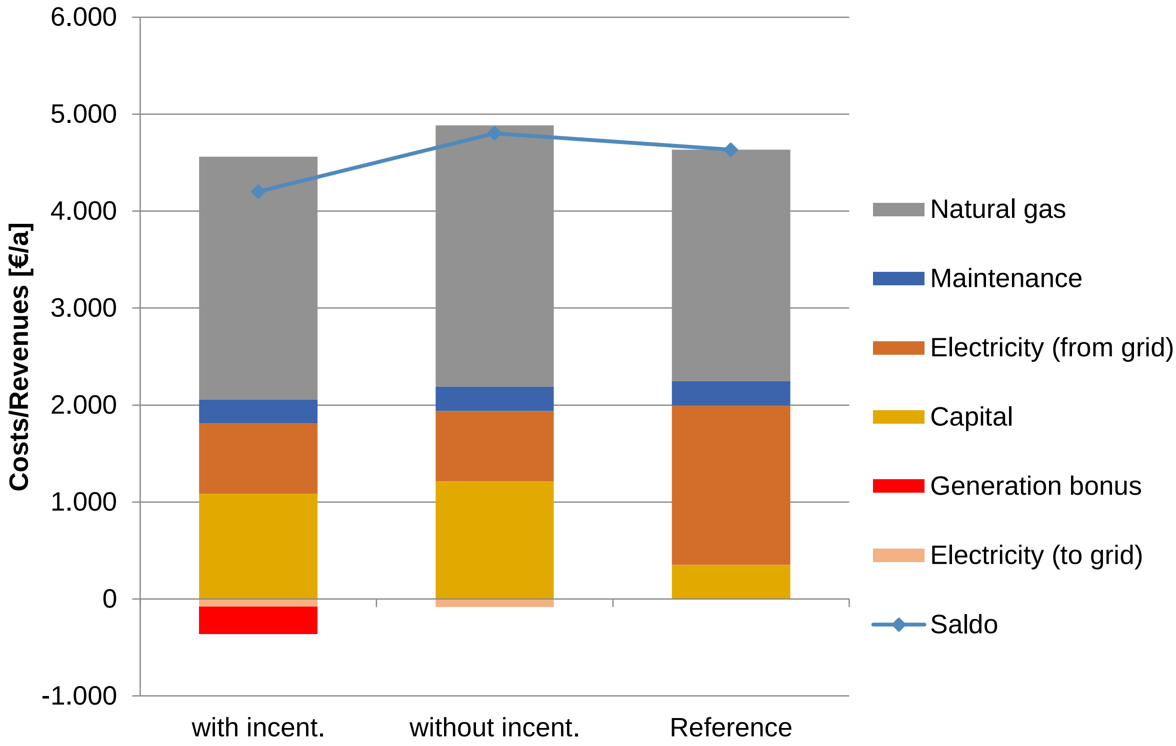


Fig.7 Comparison between the micro-CHP case with and without incentives and the reference case, in Germany

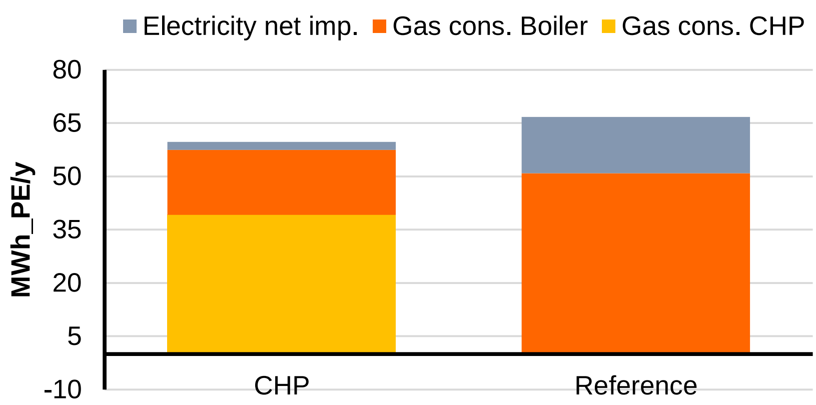


Fig.8 Energy and CO_2 emission savings derived from micro-CHP technology.

2.3 Italy

Three different case studies have been discussed to assess the influence of Italian supporting schemes for microgeneration technology:

- a multi-family house composed of three apartments for which a building-integrated micro-cogeneration system has been assessed;
- a lecture room for which a small scale trigeneration system, made up of microcogenerator (micro-CHP) interacting with a desiccant-based cooling system (DCS), has been studied;
- three public buildings representative of offices, schools and sport facilities, for which a hybrid renewable system made up of variable speed ICE and a HCPV module has been considered.

2.3.1 Case 1

Introduction

The present work deals with the effect of Italian supporting schemes on the performance assessment of a building-integrated micro-cogeneration system, which have been simulated in heating season and compared with a conventional system based on separate energy production. The study has been developed for Subtask B activity of the IEA Annex 54 where additional details about the operating conditions, the characteristics and performances of the investigated system, as well as the results of the comparison between the proposed system and the reference system can be found in [7].

The proposed system(see Table 9) basically consists of:

- 6 kW_{el} reciprocating internal combustion engine-based micro-cogeneration device fuelled with natural gas [8];
- 20kW_{th}natural gas-fired boiler [9];
- storage tank for both heating purposes and domestic hot water production [10].

This plant is devoted to satisfying the electric demand, space heating sensible load and domestic hot water requirements of a multi-family house composed of three apartments (characterized by the same useable floor area equal to 96 m^2). The building is modelled to be compliant with the transmittance values of both walls and windows suggested by the Italian Law [11].

The performance of the whole system was investigated using the whole-building simulation software TRNSYS [12]: the detailed dynamic Annex 42 model (calibrated and validated by the authors [13-15]) was used for simulating the MCHP unit operation; the type60f was used for predicting the performance of the tank, while the back-up boiler was modelled by means of the type6; the type56a was adopted to specify the building envelope characteristics, indoor air set-point temperature, infiltration load and internal gains.

The analyses were performed upon varying: i) the tank size (3 different tank volumes were considered: 855 l, 738 l, 503 l); ii) the Italian city where the building is located (4 different cities were considered: Palermo, Napoli, Roma, Milano); iii) the control logic of the cogeneration device (electric or thermal load-following operation); iv) the electric demand profile (with or without the overnight charging of an electric vehicle [16]).

Table 9. Techno-economic parameters of micro-CHP installation and reference scenario.

MICROGENERATION INSTALLATION	
MICRO-CHP UNIT	
Technology	ICE
Power output [kW_e]	6
Thermal output [kW_{th}]	11.7
Electrical efficiency [%]	28.8
Thermal efficiency [%]	56.2
Total efficiency [%]	85
Capital cost [€]	18,000
Maintenance cost [€/kWh]	0.014
ADDITIONAL HEATING BOILER	
Additional heating boiler capacity[kW]	20
Thermal efficiency [%] (function of the thermal output [14])	$\eta_p^{AS} = 0.924 + 0.000214\left(P_{th,B}^{AS} - 6.0\right)$
Capital cost [€]	1,700
Maintenance cost [€/y]	80
REFERENCE SCENARIO	
Heating boiler capacity [kW] [21]	32
Thermal efficiency [%](function of the thermal output [14])	$\eta_p^{CS} = 0.911 + 0.001067\left(P_{th,B}^{CS} - 10.44\right)$
Capital cost [€]	2,150

The performance of the system were compared with those of a conventional system composed of a 32 kW_{th} natural gas-fired boiler and a power plant connected to the central electric grid. A lower heating value of natural gas equal to 49.599 kJ/kg was assumed [17]. Table 9 shows the main techno-economic parameters of the micro-CHP installation and the reference scenario.

The comparison was performed from an economic point of view by considering both the case with incentives adopted by the Italian government to support the diffusion of Micro-CHP technology [18], and the case without taking into account the Italian policy instruments.

The policy instruments adopted by the Italian government [18] for micro-CHP units to be financially feasible mainly consist of:

- Tax Rebate (TR) on natural gas purchased;
- Tradable White Certificates (TWC), based on the primary energy saving achieved with respect the reference system;
- Government Capital Grants (GCG), associated to the purchase of the micro-CHP unit.

In the report of Subtask B of the IEA Annex 54 [7] only the Tax Rebate on natural gas purchased was considered in carrying out the economic analysis, both capital and maintenance costs were neglected.

Baseline Performance Assessment

The sensitivity analyses described in the report of Subtask B of the IEA Annex 54 [7] showed that the best energy, environmental and economic performance of the proposed system can be achieved for the following system configuration:

- Combined tank volume: 855 litres
- Italian city: Milano(latitude: 45° 28' North; longitude: 9° 10' East)
- Micro-CHP control logic: thermal load-following
- Electric demand: profile without the overnight electric vehicle charging

This result was obtained by limiting the analyses to the heating period (its duration is specified by the Italian Law depending on the region of Italy where the building is located [19]). In order to better highlight the impact of policy instruments, in this report the simulation of the above-specified configuration was extended to the whole year, with the plant operating during the summer in order to satisfy the domestic hot water requirements of the building.

The main results of the energy and environmental analyses carried out for the above-specified system configuration during the whole-year operation are reported in Table 10.

Table 10. Simulation results.

Parameters	values
Operating hours of micro-CHP	3,274
Electricity produced by the micro-CHP [MWh]	12
Electricity bought from the central grid [MWh]	11
Electricity exported to the grid [MWh]	6.1
Primary energy consumption [MWh]	84.1
PES	2.7%
CO_2 emissions [tCO_2/year]	17.8
Δm_{CO_2}	7.8%

In addition to the electric energy produced by the micro-CHP unit E_{MCHP}^{AS}, the electric energy bought from the central grid $E_{el,buy}^{AS}$, as well as the electric energy exported to the central grid$E_{el,sell}^{AS}$, the following two indicators for comparing the alternative system with the conventional system are evaluated:

$$PES = \left(E_p^{CS} - E_p^{AS}\right)/E_p^{CS} \qquad (1)$$

$$\Delta m_{CO2} = \left(m_{CO2}^{CS} - m_{CO2}^{AS}\right)/m_{CO2}^{CS} \qquad (2)$$

The Primary Energy Saving, PES, compares the total primary energy consumed by the alternative system,E_p^{SP}, with that one of the conventional system, E_p^{CS}; the avoided carbon dioxide equivalent emissions, Δm_{CO_2}, represents the percentage difference between the alternative, m^{SP}; and the conventional, m^{SP},systems in terms of carbon dioxide equivalent emissions. Additional details about the applied methodology can be found in [22].

In addition to parameters shown in Table 10, the following assumptions were considered in calculating the values reported in Table 11:

- Italian average efficiency of the power plant connected to the central electric grid, including transmission losses [20]: 0.461
- CO_2 emission factor associated to the natural gas consumption [18]: 200 gCO_2/kWh_p
- CO_2 emission factor for electricity production [23]: 525 gCO_2/kWh_e

In this section, the economic assessment of the above-mentioned system is performed without considering the Italian incentives. In particular the economic analyses were carried out by evaluating the following two indicators:

$$\Delta OC = (OC^{CS} - OC^{AS})/OC^{CS} \quad (3)$$

$$\mathrm{SPB} = (CC^{AS} - CC^{CS} - GCG^{MCHP})/(OC^{AS} + MC^{AS} - TR^{MCHP} - TWC^{AS} - OC^{cS} + MC^{CS}) \quad (4)$$

where:

OC^{AS} and OC^{CS} are the operating costs of the proposed and conventional systems, respectively; CC^{AS} and CC^{CS} are the capital costs of the proposed and conventional systems, respectively; MC^{AS} and MC^{CS} are the maintenance costs of the alternative and conventional systems, respectively; GCG^{MCHP} is the Government Capital Grant on the purchase of the MCHP unit; TR^{MCHP} is the support mechanisms that takes into account the Tax Rebate (TR) on natural gas purchased for cogenerative use; TWC^{AS} represents the incentives related to the primary energy saving achieved in comparison to the conventional system.

The unit costs of both natural gas and electric energy were assumed accordingly to the Italian scenario [19, 20]; the revenue from selling the electric energy surplus has been also taken into account.

As regards gas tariffs considered in the analysis, it is worth noting that in Italy the unit cost of natural gas CU_{ng} for residential applications is the sum of five terms [20]:

- the variable rate, depending on the region of Italy where the natural gas is consumed, as well as the level of cumulated natural gas consumption;
- the regional tax, depending on the region of Italy where the natural gas is consumed as well as the level of cumulated natural gas consumption;
- the excise tax, depending on the application (cogenerative use or uses other than cogeneration), the region of Italy where the natural gas is consumed as well as the level of cumulated natural gas consumption;
- the Value Added Tax (VAT), that depends on the level of cumulated natural gas consumption;
- the yearly fixed charge, that depends on the region of Italy where the gas is consumed.

Table 11 shows the values of the above-mentioned terms as a function of the cumulated level of natural gas in the case of the building is located in Milano.

Table 11. Natural gas unit cost as a function of the cumulated natural gas consumption in the case of residential applications.

	Cumulated natural gas consumption (Sm^3/year)					
	0 to 120	121 to 480	481 to 1560	1561 to 5000	5001 to 80000	80001 to 200000
Variable rate (€/Sm^3)	0.48008	0.57724	0.55630	0.55190	0.53283	0.50493
Regional tax (€/Sm^3)	0					
Excise tax for cogenerative use (€/Sm^3)	0.0004493					
Excise tax for applications other than cogeneration (€/Sm^3)	0.044	0.175	0.17	0.186	0.186	0.186
VAT(%)	10	10	21	21	21	21
Yearly fixed charge (€/year)	84.1					

*applied only to a portion of the total natural gas consumption (equal to 0.22 m^3/kWh_{el} [24] times the total electric energy produced by the cogeneration device); 0.012498 €/Sm^3 is the excise tax to be applied to the remaining part of the natural gas consumed for cogenerative uses.

The difference in terms of excise tax between cogenerative use and uses other than cogeneration is the above-mentioned incentive named “Tax Rebate (TR)”, described in the following session.

Regarding the electric energy purchased from the grid, it can be highlighted that in Italy the residential consumers have time-of-use rates for the electricity prices. According to the Italian scenario [20], the unit cost of purchased electric energy $CU_{el,buy}$ varies depending on: i) the day, ii) the hour of the day, iii) the level of cumulated electric energy consumption.

The unit cost of electric energy purchased from the grid during a week day and a weekend day is reported in Fig. 9a and Fig. 9b, respectively, as a function of both the hour of the day and the cumulated electric energy consumption. The values specified in this figure include the excise tax (0.0227 €/kWh) and the VAT (10%).

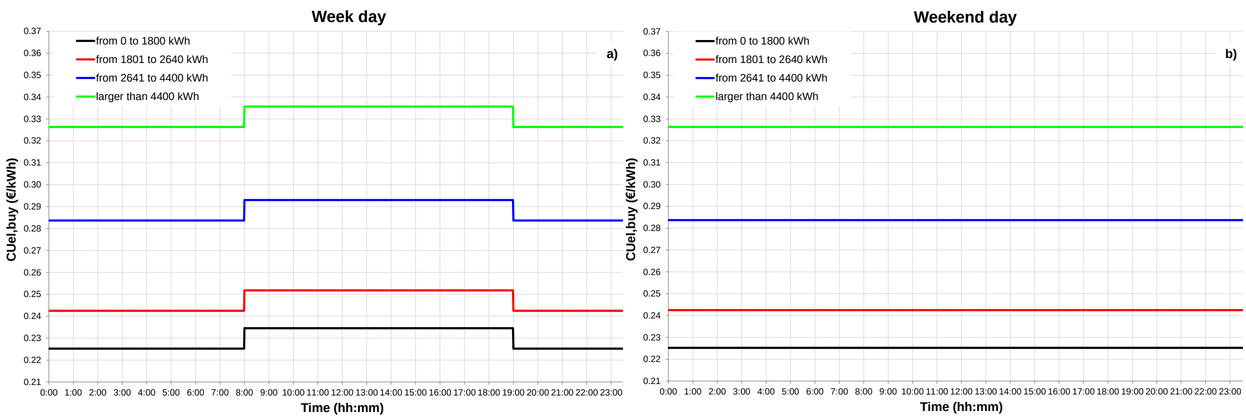


Fig.9 Unit cost of electric energy purchased from the grid during a week day (a) and during a weekend day (b).

According to the Italian Law [20], the unit cost of the electric energy sold to the national central grid $CU_{el,sell}$ depends on: i) the city; ii) the day (week day, Saturday and Sunday are differentiated) , iii) the hour of the day.

Fig. 10 reports the values of $CU_{el,sell}$ as a function of the hour of the day for a week day, Saturday and Sunday in the case of the building is located in Milano.

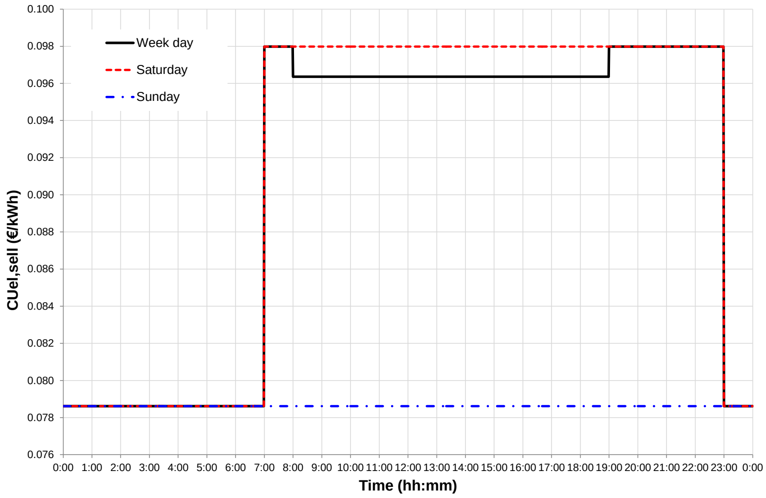


Fig.10 Unit cost of electric energy sold to the grid during week day, Saturday and Sunday.

Table 12 sums up the main results of the economic assessment performed without considering the Italian incentives. The value of SPB reported in this table was obtained by assuming equal to zero the values of the parametersGCG^{MCHP}, $TR^{MCHP}$and TWC^{AS} used in Eq. 4

Table 12. Results without incentives.

	Microgeneration	Reference scenario	Δ
Operating cost [€/y]	8,408	8,437	4.7%
PE [MWh_PE/y]	84.1	86.4	2.7%
CO_2 [tCO_2/year]	17.8	19.3	7.8%
SPB [years]	83.8		

Performance Assessment with Support Mechanism

In this section the influence of Italian policy instruments on the economic performance of the above-mentioned building integrated micro-cogeneration system is evaluated.

As above-mentioned the support mechanism considered in the analysis are:

- Tax Rebate (TR) on natural gas purchased;
- Tradable White Certificates (TWC), based on the primary energy saving achieved with respect the reference system;
- Government Capital Grants (GCG), associated to the purchase of the micro-CHP unit

About "Tax rebate" support mechanism it can be noticed that, according to the Italian Law, the reduced excise tax for cogenerative uses has to be applied only to a portion of the total consumed volume of natural gas: this portion is equal to the so-called "specific consumption" (equal to 0.22 m^3/kWh_{el} [24]) times the total electric energy produced by the cogeneration device; 0.012498 €/Sm^3 is the excise tax to be applied to the remaining part of the volume of natural gas consumed for cogenerative uses.

The number of Tradable White Certificates depends on the primary energy saving achieved in comparison to the conventional system calculated according to the Italian Law [25]: the number of Tradable White Certificates can be calculated as the product of this energy saving (expressed in TOE) and a multiplication factor equal to 1.4. In this study an energy saving equal to 0.221 toe has been obtained, while 86.98 € has been assumed as the value of each Tradable White Certificate.

In this study the incentive named Government Capital Grant has been assumed equal to the 40% the capital cost of the micro-CHP unit according to the Italian Law [25].

Table 13 sums up the main results of the case with incentive

Table 13. Results with incentives.

	Microgeneration	Reference scenario	Δ
Operating cost [€/y]	6,867	8,437	18.6%
PE [MWh_PE/y]	84.1	86.4	2.7%
CO_2 [tCO_2/y]	17.8	19.3	7.8%
SPB [years]	7.5		

Finally Table 15showsthe value of SPB, calculated according to Eqs. 3 and 4, as a function of the support mechanism taken into consideration.

Table 14. Economic comparison between the proposed system and the reference system by taking into account the Italian incentives.

	ΔOC (%)	SPB (years)
All Italian incentives	18.6	7.5
Only "Tax Rebate on natural gas purchased"	18.2	13.0
Only "Tradable White Certificates"	5.0	74.3
Only "Government Capital Grants"	4.7	49.4

Discussion

The analysis of the data reported in both Table 12 and Table 14 allow highlighting the influence of the Italian incentives with respect to the system configuration analysed in this report:

- whatever the policy instrument is, the proposed system reduces the operating costs relative to the conventional system (Table 14);
- without the support mechanisms adopted by the Italian Government (Table 12), the duration of the Simple Pay Back period (83.8 years)is longer than the lifetime of the technologies;
- by considering all Italian incentives (Table 14), the duration of the Simple Pay Back period (7.5 years) becomes economically acceptable;
- among the three support mechanisms, the most effective in terms of economic incentive is the Tax Rebate on natural gas purchased; the incentive associated to the Tradable White Certificates are less suitable from an economic point of view in the case analysed.

2.3.2 Case 2

Introduction

The analysed system (referred as Alternative System, AS) consists of a small scale trigeneration system, in which a heat-led microcogenerator (micro-CHP) interacts with a desiccant-based cooling system (DCS), equipped with a silica-gel desiccant wheel (DW). The system provides the air-conditioning service to a lecture room (63.5 m^2 floor area, operating profile from Monday to Saturday from 9:00 to 19:00) during summer and winter periods.

During summer operation (1st June – 15th September), the DW balances the latent load of the process air, while an electric chiller manages the sensible load, by means of a cooling coil. The micro-CHP provides thermal energy to regenerate the desiccant wheel, by means of a thermal storage tank; a peak load boiler, fuelled with natural gas, provides thermal energy integration. Electricity from the cogenerator is used to drive the electric chiller, the auxiliaries of the Air Handling Unit (AHU) and of the micro-CHP itself (fans and pumps) as well as further eventual appliances of the lecture room (lights, computers, etc.).

During winter operation (15th November – 31th March), the micro-CHP provides thermal energy for space heating purposes. Electricity is supplied to auxiliaries and electric appliances.

During intermediate operation (1st April – 31st May; 16th September – 14th November), the AHU is inactive and cogenerated electricity is supplied to electric appliances of the lecture room. Furthermore, throughout the year, the micro-CHP provides thermal energy, by means of the storage tank, for domestic hot water (DHW) preparation, to a nearby user (a gym), with a requirement of 1200 litres per day.

In Table 15, the annual loads are reported:

The trigeneration system is compared with a reference system (Conventional System, CS), equipped with a conventional air handling unit, based on cooling dehumidification during summer period.

Electricity to power an electric chiller, the auxiliaries of the AHU, as well as electric appliances is drawn from the grid.

Thermal energy for winter space heating, air post-heating during summer and DHW purposes is provided by a natural gas boiler.

Table 15. User annual loads.

Parameter	Value
Space heating demand [kWh/y]	6,511
DHW demand [kWh/y]	16,020
User electricity demand [kWh/y]	8,827
Cooling demand [kWh/y]	4,044

In Table 16 the energy requirements of the AHUs in AS and CS during summer period are summarized. During winter period, the auxiliaries consumption for both AS and CS is the same (924 kWh/y). Finally, a further auxiliary consumption in the AS due to the circulation pump between the MCHP and the storage tank (383 kWh/y) has to be taken into account.

In Table 17 the nominal data of the CS consisting of a condensing boiler and an electric chiller, and for the AS are reported.

Table 16. Energy requirements of the AHU in AS and CS during summer period.

AS	**Heat demand for DW regeneration of the AHU**	kWh/y	6,948
	Electricity demand for chiller of the AHU	kWh/y	1,402
	Electricity demand for auxiliaries of the AHU	kWh/y	1,417
CS	**Heat demand for air post-heating of the AHU**	kWh/y	1,412
	Electricity demand for chiller of the AHU	kWh/y	3,103
	Electricity demand for auxiliaries of the AHU	kWh/y	627

In terms of economic performance, the effect of three policy instruments on the feasibility of the system is analysed: i) a subsidy on gas price, ii) a CHP generation bonus and an iii) investment subsidy.

As regards the subsidy on gas price for CHP, the support mechanism [27] states that 0.22 m^3 per kWh of generated electricity can access a reduced excise tax (0.0004493 €/m^3, reduced to 0.00013479 €/m^3 if more than 70% of cogenerated electricity is consumed on site); the remaining amount of consumed natural gas can access, in the case of trigeneration systems, the excise tax for industrial uses (0.012498 €/m^3), that is much lower than the one for civil uses (from 0.12 to 0.15 €/m^3, depending on the range of annual consumption).

TWC achieved by the micro-CHP, according with the Ministerial Decree 5/09/2011. Finally, as regards the investment subsidy, the same Ministerial Decree foresees that, for high-efficiency cogenerators, the white certificates mechanism can be combined with guarantee or revolving funds, as well as with other public grants not exceeding 40% of the investment cost for plants with electric power up to 200 kW.

Therefore a reduction of 40% of the investment cost was assumed for the micro-CHP.

Table 17. Techno-economic parameters of micro-installation and reference scenario.

MICROGENERATION INSTALLATION	
MICRO-CHP UNIT	
Technology	ICE
Power output [kW_e]	5.6
Thermal output [kW_{th}]	11.7
Thermal input [kW_{th}]	20.8
Total efficiency	83%
Capital cost [€]	18,000
DESSICANT-BASED COOLING SYSTEM	
Capital cost [€]	3,000
ADDITIONAL HEATING BOILER	
Additional heating boiler capacity[kW]	16.5
Thermal efficiency [%] [21]	90%
Capital cost [€]	1,500
COOLING DEVICE	
Vapour compression chiller capacity [kWfr]	8.5
COP	2.98
Capital cost [€]	3,000
REFERENCE SCENARIO	
Condensing heating boiler capacity [kW] [21]	28.2
Thermal efficiency [%]	98%
Capital cost of the heating boiler [€]	3,000
Vapour compression chiller capacity [kW_{fr}]	16.3
COP	2.7
Capital costof the chiller [€]	5,753

Baseline Performance Assessment

Table 18 shows the main technical and economic parameters used in the analysis. For the electricity price, an average value for the three time slots currently adopted in Italy was assumed. The feed in tariff was evaluated considering the average on the three time slots of the economic value of electricity exported to the grid, according to the net metering scheme, introduced by Italian Authority for Electricity and Gas (AEEG) for cogeneration plants with electric power up to 200 kW (Resolution June 3, 2008-ARG/elt 74/08).

Table 18. Technical and economic parameters used in the study.

Parameter	Value
PE factor for NG [kWh_PE/kWh]	1
PE factor for electricity grid mix [kWh_PE/kWh]	2.38
PE factor for electricity feed in mix [kWh_PE/kWh]	2.30
CO_2 factor for NG [g/kWh]	207
CO_2 factor for electricity grid mix [g/kWh]	573
CO_2 factor for electricity feed in mix [g/kWh]	550
Electricity purchasing price [c€/kWh]	21.1
Feed in tariff to grid [c€/kWh]	8.79
NG price [c€/kWh]	9.88

In Table 19 the primary energy consumption of the conventional system and of the alternative system is shown. A LHV=9.52 kWh/m^3 for natural gas has been assumed. As a comparison between energy performance of AS and CS, the former allows to achieve a primary energy saving of 4.74 MWh/y, equal to 8.39%. The same Table shows the CO_2 emissions of the alternative and the conventional system. As a comparison between environmental performance of AS and CS, the former allows to achieve a CO_2 emission saving of 2.14 t/a, equal to 16.7%.

With regards to the economic analysis without incentives, the AS shows to be not economically convenient due to the incidence of the investment cost and the increase in operating cost.

Table 19. Results without incentives.

	Microgeneration	Reference scenario	Δ
Total cost [€/y]	8,909	6,324	41%
Saldo [€/y] (cost-revenues)	8,406	6,324	33%
Operating costs [€/y]	6,769	5,708	17%
PE [MWh_PE/y]	51.7	56.53	-9%
CO_2 [tCO_2/y]	10.7	12.8	-16%
CO_2 abatement costs [€/t]	975		
PE abatement costs [€/MWh]	439		
SPB [years]	/		

Performance Assessment with Support Mechanism

In Table 20 the energy and economic analysis for the alternative system with support mechanisms is reported. The directive requirement on high efficiency cogeneration is achieved (PES > 0), therefore the three previously described support mechanisms can be contemporary applied.

Table 20. Results with incentives.

	Microgeneration	Reference scenario	Δ
Total cost [€/y]	7,314	6,324	16%
Saldo [€/y] (Cost – revenues)	6,699	6,324	6%
Operating cost [€/y]	5,799	5,708	2%
PE [MWh_PE/y]	51.8	56.5	-9%
CO_2 [tCO_2/y]	10.7	12.8	-16%
CO_2 abatement costs [€/t]	179		
PE abatement costs [€/MWh]	69		
SPB	18.2		

For the alternative system with support mechanism, the Simple Pay Back (SPB) period was also evaluated, by means of the following Equation:

$$SPB = \frac{Additional\ investment}{Savings\ in\ operation} = \frac{Investment\ cost\ of\ AS - Investment\ cost\ of\ CS}{Operating\ cost\ of\ CS - Operating\ cost\ of\ AS + Sum\ of\ Revenues}$$

The performance of the AS and CS strongly depend on several operating conditions, first of all the electric demand profile, that influences the share of own use electricity. In Table 21 the Primary Energy and CO_2 emissions saving, as well as the SPB, are shown as a function of this share. The most affected performance is the economic one, as the SPB drastically reduces from about 20 to lower than 10 years, if the electricity consumed on-site raises from 60 to 90%.

For the optimal case detected in Fig. 11 (share of own use electricity = 90%), a comparison between Subtasks B and C is performed (Tab. 21).

Table 21. Comparison between Subtask B and Subtask C results.

		Subtask B	Subtask C
Primary Energy Saving		6.1 %	9.0 %
CO_2 Saving	%	14.8 %	17.5 %
SPB with support mechanism [years]		10.2	8.9
Saldo AS – Saldo CS [€/y]		-38.0	-171.0

The results for Subtask B were achieved with dynamic simulations by means of TRNSYS software, therefore they take into account some effects that are neglected by the economic assessment spreadsheet tool (see Appendix), such as thermal losses of the storage tank, partial load operation of the chillers and so on. These effects lead to slight lower performance indices for the AS within Subtask B approach. However, the simplified methodology proposed by the assessment spreadsheet tool can calculate the energy, environmental and economic performance of the systems with satisfying accuracy with respect to a dynamic simulation tool. The results reported in the report of Subtask B [26] are slightly different from those in Table 21, mainly due to a different reference system for thermal energy production and a different approach in calculating the primary energy related to electricity fed into the grid.

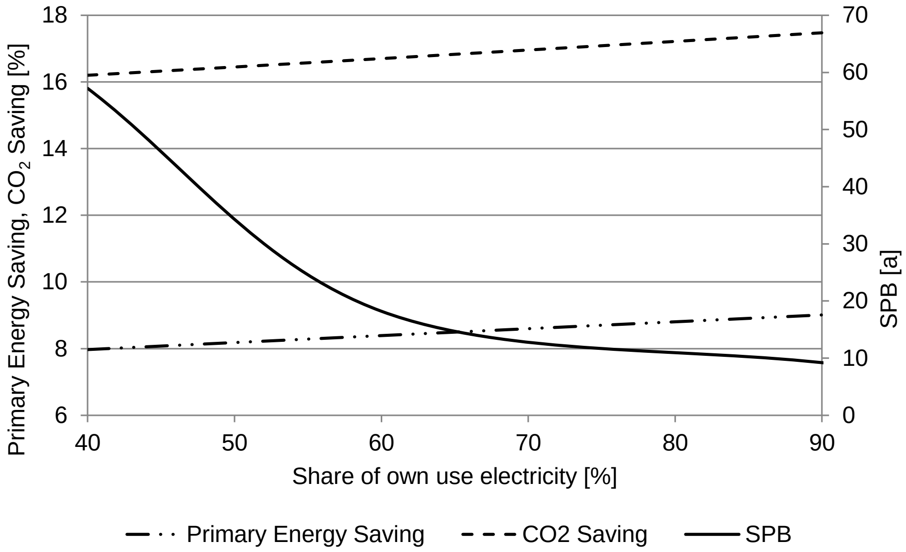


Fig.11 Primary energy saving, CO_2 emissions saving and SPB as a function of the share of own use electricity.

Discussion

The analysed system is favourable with respect to the conventional one, in terms of energy and environmental performance, achieving a primary energy saving of about 8-10% and a CO_2 emissions saving of about 16-18%, depending on the share of own use electricity.

However, to guarantee the economic feasibility of the system, it is necessary that it can access the support mechanisms introduced by Italian legislation for small scale gas fuelled trigeneration systems: a lower taxation on gas price, the white certificates, an investment subsidy (up to 40% of the investment cost) and the net metering scheme. In fact, if the analysed system can access benefit from all these mechanisms, a reduction of about 82% of the CO_2 and PE abatement costs can be achieved, as well as a quite acceptable simple payback period of about 9 years (achieved with a share of own use electricity equal to 90%).

2.3.3 Case 3

Introduction

Case 3 assesses the influence of Italian supporting schemes on the performance of a hybrid micro Combined Cooling Heat and Power, micro-CCHP, system, whose power units consist of a variable speed ICE cogenerator and a High Concentrator Photovoltaic, HCPV, system.

The hybrid system under analysis has been applied to representative public buildings of a small urban area in Central Italy. Three building typologies have been considered in the analysis: i) office buildings, ii) school buildings and iii) sport facilities. One representative building has been assumed for each typology.

Bespoke models have been developed in Matlab/Simulink environment, in order to assess the performance of the power units in different operating conditions. The main characteristics of the two systems are reported on Table 22.

The hybrid micro-CCHP system has been assessed with respect to a reference scenario, the separate energy production, in which the electricity is bought from the grid and the thermal demand is satisfied by a heating boiler.

Table 22 also reports the size of the PV plant analysed in the three case studies, which has been sized on the basis of the following criteria:

- the sum of ICE and HCPV electrical output should be lower than 50kWe in order to respect the defined limit of micro-generation systems reported in the EU cogeneration directive [28];
- the size of the ICE is the nearest to the peak load of the end-user
- HCPV size has been designed on the basis of the peak load of the end-user, with the constrain of the installation space availability on the considered building and the micro-generation limit.

In order to consider the influence of ambient condition and the effect of varying fuel and electricity prices, an optimization approach has been adopted for the management of the hybrid system. The developed algorithm follows a multi-objective approach, aiming at minimising operating costs, primary energy usage and carbon dioxide emissions. For the calculation, all the three objectives have been expressed on cost basis, and weighting factors have been defined 'a priori'.

The costs of CO_2 emissions and of the primary energy have been calculated multiplying, respectively, the total CO_2 emission and the primary energy of the alternative system times their specific cost (730 €/toe and 243 €/tCO_2 respectively). These values are obtained by the average crude oil cost; the cost of CO_2 emissions has been evaluated considering that each ton of oil equivalent corresponds, on average, to 3 tCO_{2eq}/toe, which results from a rough average of the physical conversion factors related to the fuels used (for example 2.349 tCO_2/t and gas/diesel oil, 3.101 tCO_2/t).

Linear programming techniques have been implemented, taking the advantage of rapid calculations. For this purpose, an iterative procedure has been studied in order to overcome the non-linearity determined by the ICE module (since its output is based on the engine performance maps).

A study of the above-mentioned hybrid plant is reported in the Subtask B activity of the IEA Annex 54 where additional details about the models' developed, the optimization procedures and the performance assessment without considering the introduction of incentives, can be found [29].

Table 22.Technical and economic parameters of hybrid renewable installation and reference scenario.

HYBRID RENEWABLE SYSTEM	
MICRO-CHP UNIT	
Technology	ICE
Max Electric power [kWe]	14
Max Thermal power [kW_{th}]	29
Thermal input [kW_{th}]	49
Total efficiency	28.5%
Capital cost [€/kW]	1,000
HCPV	
Peak electric power [kW_p]	School 9.6 Office 8.3 Sport facility 7
Power output of the single module (DNI 900 W/m2, ambient temp. 25°C)	70 W
Cell Typology	Monolithic Triple Junction
Cell dimension	Circular, 2.3 mm diam.
Cell efficiency (flash test)	41%
Optics	Fresnel lens and secondary optics
Optics efficiency (on axis)	85 %
Dimensions	1.6x0.4x0.4 m
Capital cost [€/kW_p]	3,500
ADDITIONAL HEATING BOILER	
Additional heating boiler capacity[kW_{th}]	School 73 Office 68 Sport facility 73
Thermal efficiency [%]	90%
REFERENCE SCENARIO	
Heating boiler capacity [kW_{th}]	School 73 Office 68 Sport facility 73
Thermal efficiency [%]	90%

As regards Italian incentives, the combined usage of solar power system and micro-CHP devices is eligible of:

- feed-in tariff for the electricity produced by the HCPV system;
- tax rebate on part of the natural gas feeding the cogeneration unit
- Tradable White certificate, TWC, certifying the energy savings that can be achieved: each ton of oil equivalent, toe, of electric and/or thermal energy saved corresponds to a TWC. It has

been assumed a selling price for TWC, of 100 €/TWC, which is the current price in bilateral agreements (this value is higher than official price recognised by the Italian Regulatory Authority to obliged parties, which is 86.98 €/TWC).

Unlike previous studies, a simplified approach has been used to assess the revenues coming from tax rebates. In fact, the calculation of this revenue, which is a function of the electricity produced, would have introduced a non linearity in the objective function. Thus, a reduced price has been applied to the NG feeding the micro-CHP system.

Baseline Performance Assessment

This section shows the performance assessment of the described hybrid micro-CCHP system without considering the Italian supporting schemes, as reported in [7].The main technical and economic parameters used in the study are reported in Table 23.

Table 23. Techno- economic parameters used in the study.

	Parameter
PE factor for electricity [KWh_PE/kWh]	2.7
PE factor for NG [kWh_PE/kWh]	1.1
CO_2 factor for NG [g/kWh]	200
CO_2 factor for electricity [g/kWh]	523
Electricity purchasing price [€/kWh]	0.175
Feed in tariff to grid [€/kWh]	0.101
NG price [€/kWh]	0.058
NG price rebated [€/kWh]	0.045
Feed in tariff for electricity from HCPV [€/kWh]*	0.105
TWC price [€]	100

*the value comprise the electricity sold to the grid and a premium in case of own-use electricity

Results have been obtained giving the same weight to the three criteria. In order to give the same weight to all criteria, since the minimization of the CO_2 emissions and of the primary energy consumption identify the same operating point a value of 0.5 has been assumed for the cost criteria (w_1) and a value of 0.25 has been assumed for the other two criteria (w_2=w_3=0.25).

Table 24 compares primary energy consumption and carbon dioxide emissions of the hybrid renewable system with the reference system and shows the SPB of the installation.

Table 24. Optimization results without incentives.

OFFICE	Microgeneration	Reference scenario	Δ
Operating costs [€]	5,359	9,011	-41%
PE [MWh_PE/y]	70.5	121	-42%
CO_2 [tCO_2]	18.2	31.3	-42%
SPB [year]	13.0		
CO_2 abatementcost [€/t]	278.0		
PE abatement cost [€/MWh]	71		

SCHOOL			
Operating costs [€]	4,949	8,035	-38%
PE [MWh_PE/y]	67.7	119.4	-43%
CO_2 [tCO_2]	17.5	30.8	-43%
SPB [year]	14		
CO2 abatementcost [€/t]	230.7		
PE abatement cost [€/MWh]	59		
SPORT FACILITY			
Operating costs [€]	6,315	9,680	-29%
PE [MWh_PE/y]	74.8	131.8	-41%
CO_2 [tCO_2]	21.6	36.6	-41%
SPB [year]	11.4		
CO_2 abatement cost [€/t]	225.3		
PE abatement cost [€/MWh]	59		

The natural gas price in this study is lower than the one of the previous study, since the buildings under analysis are public buildings, managed by a Local Administration, for which a lower price of energy carriers can be negotiated.

Performance assessment with support mechanism

Table 25 shows the optimization results of the hybrid system with incentives. Adopting a Multi Objective Linear Programming technique, no differences in operating conditions can be found with respect to the case without incentives when the same weight is given to the three criteria.

The main effect of the support mechanisms is a strong reduction in the SPB, which can push hybrid renewable systems enter the market.

Primary energy and CO_2 emission reductions are about 40% for all the three case analysed, highlighting the effectiveness of introducing such hybrid systems.

Considering only a minimization cost criteria (w_1=1; w_2=w_3=0), the main operation parameters of the system change: the micro-CHP unit is switched on only when the electricity purchasing price is high (Table 26).

In such cases, the energy bill is slightly lower and provides a reduction in the energy bill for the office case; the effect, indeed, depends on the energy load of the end user. As regards the carbon dioxide emissions and the primary energy consumption, a slight increase is recorded.

Table 25. Optimization results with incentives(w_1=0.5, w_2=0.25, w_3=0.25).

OFFICE	Microgeneration	Reference scenario	Δ
Energy bill (cost-revenues) [€]	3,216.9	9,011.0	-64%
PE [MWh_PE/y]	70.5	121.0	-42%
CO_2[tCO_2]	18.2	31.3	-42%
SPB [year]	7.9		
CO_2 abatement cost [€/t]	441		
PE abatement cost [€/MWh]	114		
SCHOOL			
Energy bill (cost-revenues) [€]	2,854.0	8,035.0	-64%
PE [MWh_PE/y]	67.7	119.4	-43%
CO_2[$tCOtCO_2$]	17.5	30.8	-43%
SPB [year]	7.9		
CO2 abatement cost [€/t]	388.6		
PE abatement cost [€/MWh]	100.3		
SPORT FACILITY			
Energy bill (cost-revenues) [€]	3,985.4	9680.0	-59%
PE [MWh_PE/y]	83.85	141.7	-41%
CO_2[$tCOtCO_2$]	21.6	36.6	-41%
SPB [year]	6.4		
CO_2 abatement cost [€/t]	381.4		
PE abatement cost [€/MWh]	98.4		

Table 26. Optimization results with policy mechanisms (w_1=1, w_2=0, w_3=0).

OFFICE	Microgeneration	Reference scenario	Δ
Energy bill (cost-revenues) [€]	3,066	9,011	-66%
PE [MWh_PE/y]	74	121	-39%
CO_2 [$tCOtCO_2$]	19.1	31.3	-39%
SPB [year]	7.8		
SCHOOL			
Energy bill (cost-revenues) [€]	2,817	8,035	-65%
PE [MWh_PE/y]	67.7	119.4	-43%
CO_2 [$tCOtCO_2$]	17.5	30.8	-43%
SPB [year]	7.8		
SPORT FACILITY			
Energy bill (cost-revenues) [€]	3,939	9,680.0	-59%
PE [MWh_PE/y]	85.14	141.7	-40%
CO_2 [$tCOtCO_2$]	22.0	36.6	-40%
SPB [year]	6.3		

Discussion

Fig. 12 shows the effect of each single mechanism on SPB:

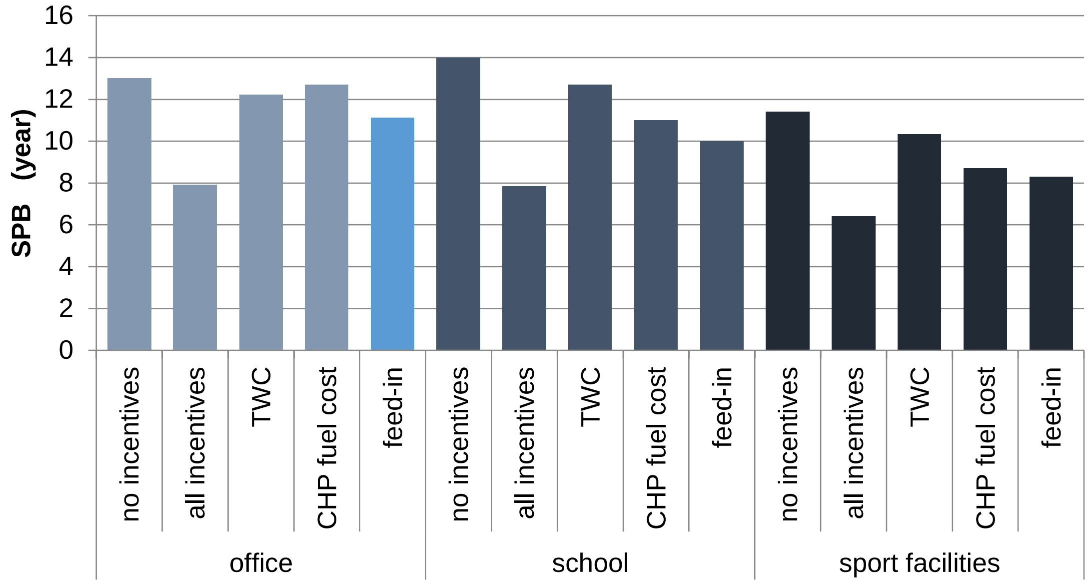


Fig.12 Effect of incentives on SPB for the three case analysed

The main contribution is given by the FiT scheme, followed by TWC and finally by the reduction in the fuel cost (tax rebate) feeding the CHP system. Differently from the previous study, the natural gas tariff is lower, thus the effect deriving from the tax rebate is reduced.

The main result coming from the introduction of incentives is an increase in savings and, consequently, an interesting reduction in SPB.

2.4 Canada

The section presents three different case studies in order to assess the influence of support mechanisms on microgeneration performance:

- Case 1 describes the opportunities deriving from a TOU tariff for a 1 kW_e Proton-Exchange Membrane Fuel-Cell, PEMFC, coupled to a lithium bromide battery for electrical storage
- Case 2 discusses the influence of Canadian supporting scheme on a ICE and Stirling engine system applied to a single-family dwelling
- Case 3 analyses the effect of Canadian supporting scheme on two hybrid renewable systems in load sharing application.

It is worthy of note that the study of case 2 and 3 derives from a collaboration between Canada and Korea.

2.4.1 Case 1

Introduction

The present work investigates the application of a 1 kW_e Proton-Exchange Membrane Fuel-Cell, PEMFC, coupled to a lithium bromide battery for electrical storage, which can take advantage of the time-of-use tariff, currently available in Ontario, Canada, on the basis of which different cost rates are applied for off, mid and on-peak periods.

Electrical time-of-use billing schedules provide a financial incentive that encourages residential consumers to shift their electrical consumption away from periods of peak demand. Consequently, there are opportunities for residential consumers to take advantage of time-of-use billing schedules via micro-cogeneration systems that integrate batteries for electrical storage.

Furthermore in jurisdictions where the cost of natural gas is low compared to the cost of electricity for residential consumers, PEMFC based micro-cogeneration systems have the potential to provide primary energy and cost benefits for this sector. One such jurisdiction is Ontario, Canada.

This simulation-based research [30] investigates the primary energy and associated cost savings seen by a 180 m^2 row house (that is attached on both sides) with an integrated 1 kW_{AC} PEMFC coupled to a lithium-ion battery for electrical storage. The simulations were performed on an annual basis using ESP-r. The PEMFC was simulated using the EBC Annex 42 model as modified and calibrated by [31]. The lithium-ion battery model that was simulated consisted of four sets in parallel of fourteen single cells. This battery had a fully charged capacity of approximately 150 Ah and a potential of 58 V.

Table 27. Techno-economic parameters of micro-CHP installation reference scenario.

MICROGENERATION INSTALLATION	
MICRO-CHP UNIT	
Technology	PEMFC
Power output [kW_e]	1
Thermal output [kW_{th}]	1.6
Electrical efficiency [%]	0.35
Thermal efficiency [%]	0.55
Total efficiency [%]	0.85
Capital cost [CAN$] [32]	32,324
ADDITIONAL BOILER	
Boiler capacity [kW]	27
Boiler efficiency [%]	85%
BATTERY	
Typology	Li-ion battery
Fully charged capacity [Ah]	150
Potential	
REFERENCE SCENARIO	
Heating boiler capacity [kW]	27
Thermal efficiency [%]	85%

The charge/discharge behaviour of a single cell of this large scale battery was calibrated with experimental data gathered from a single 38 Ah lithium-ion cell by members of the National Research Council of Canada and Natural Resources Canada. Further details on the configuration of the simulation are provided by [30].

Baseline performance assessment

The baseline corresponds to separate energy production. In this scenario 12.8 GJ of electricity were consumed along with 1989 m^3 of natural gas. The associated energy cost was 498 $(CAN). The TOU tariffs in Ontario are 5.9 c$(CAN)/kWh, 8.9 c$(CAN)/kWh and 10.7 c$(CAN)/kWh for respectively off peak, mid peak and on peak hours, whilst the natural gas price is 0.118$(CAN)/$m^3$.

Performance assessment with support mechanism

Several scenarios were simulated in this research that investigated different methods of controlling the PEMFC and lithium-ion battery, only the control of the output of these devices was varied. The different control scenarios as well as the most important performance metrics are summarized in Table 28. There were two methods of controlling the output of the PEMFC that were studied. In the first method, the PEMFC was controlled to output at its maximum rate (1 kW_{AC}) for the duration of the annual simulation. This method of PEMFC output control is indicated by the "1" label in the "PEMFC output" column in Table 28.

Table 28. Performance metrics for PEMFC and lithium-ion battery control scenarios that were investigated

No	Battery On-Peak Output (kW)	PEMFC Output (kW)	Net Electricity Consumption (GJ)	Natural Gas Consumption (m^3)	Primary Energy Cost ($CAN)	Effective PEMFC Efficiency
1	-	-	12.8	1,989	498	-
2	-	1	-16.3	3,236	62	0.68
3	-	1/0.25	-9.3	2,692	138	0.73
4	5	1/0.25	-8.0	2,692	81	0.73
5	2.5	1/0.25	-8.3	2,692	72	0.73
6	nonHVAC	1/0.25	-9.2	2,692	132	0.73
7	5	-	14.1	1,989	441	-
8	2.5	-	13.8	1,989	432	-
9	nonHVAC	-	13.0	1,989	477	-

In the second method, the PEMFC was controlled to output at its maximum value for the duration of the year except during the summer when the PEMFC was modulated down to its minimum value (0.25 kW_{AC}). This method of PEMFC output control is indicated by the "1/0.25" label in the "PEMFC Output" column in Table 28.

To understand how the output of the lithium-ion battery was controlled it is first important to understand the time-of-use electricity cost schedule that was used in this research. This cost schedule is defined by the Ontario government. According to this schedule, different electricity cost rates are applied for off, mid and on-peak periods of use from least to most expensive. In this research, the battery was charged at a rate of 2.5 kW for all cases where it was used during off-peak periods. The battery was discharged during on-peak periods at either 5 kW, 2.5 kW or its output was made to match the non-HVAC demand of the occupant. These control mode scenarios are labelled as "5", "2.5" or "nonHVAC" in the "Battery On-Peak Output" column of Table 28.

To sum up, the cases analysed are:

- *Case 1*: reference scenario, without the use of the PEMFC or lithium-ion battery.
- *Case 2*: electrical output of the PEMFC sets to maximum continuously for the entire annual simulation.
- *Case 3*: electrical output of the PEMFC sets to maximum during the heating season and minimum during the cooling season.
- *Case 4*: electrical output of the PEMFC sets to maximum during the heating season and minimum during the cooling season; the PEMFC is coupled to a single Lithium Ion battery, which can output at a constant rate of 5 kW.
- *Case 5*: electrical output of the PEMFC sets to maximum during the heating season and minimum during the cooling season; the PEMFC is coupled to a single Lithium Ion battery, which can output at a constant rate of 2.5 kW.
- *Case 6*: electrical output of the PEMFC sets to maximum during the heating season and minimum during the cooling season; the PEMFC is coupled to a single Lithium Ion battery, which can output at a variable rate to serve the portion of the occupant non-HVAC loads that are not met by the PEMFC output.
- *Case 7*: Lithium Ion battery which can output at a constant rate of 5 kW.
- *Case 8*: Lithium Ion battery which can output at a constant rate of 2.5 kW.
- *Case 9*: Lithium Ion battery which can output at a variable rate to serve the portion of the occupant non-HVAC loads that are not met by the PEMFC output.

Discussion

The primary energy savings of the control modes where the battery and PEMFC were used (modes 2-9) can be evaluated by comparing the performance metrics to the baseline (mode 1). By comparing modes 2-6 to mode 1 it can be seen that the PEMFC significantly reduces electricity consumption (to the point where there is electricity production) at the expense of increased natural gas consumption. Due to the relatively low natural gas cost relative to the electricity cost, a modest primary energy cost savings is achieved by use of the PEMFC. Note that the primary energy costs shown in Table 29 assume that electricity can always be sold back to the grid at the current time-of-use purchase price.

The impact of modulating the output of the PEMFC down to its minimum value during the summer can be understood by considering the "Effective PEMFC Efficiency" column in Table 29. Since there is not always a demand for the thermal output of the PEMFC, some of its thermal output is excessive and must be wasted to the ambient outdoor environment. This wasted thermal output is particularly high during the summer when there is no demand for space heating. The effective PEMFC efficiency is essentially the total PEMFC efficiency that has been adjusted to account for this wasted heat. By comparing control mode 2 to control modes 3-6, it can be seen that the effective efficiency increases modestly due to the reduction of the PEMFC's output during the summer and associated wasted heat.

By charging the battery during off-peak periods and discharging it during on-peak periods, the battery is able to store electricity when it can be purchased cheaply for use when electricity is more expensive. By comparing control mode cases 7-9 to case 1 it can be seen that this can result in modest primary energy cost savings. It can also be seen that the battery increases net electricity consumption. This is because of inefficiencies associated with the inverter and rectifier that are necessary for the battery's use. The battery also has an internal resistance that causes energy losses during charging and discharging. By examining control modes 7 and 8 it can be seen that discharging the battery at a lower rate can help mitigate the negative effects of the battery's internal resistance.

2.4.2 Case 2

The present paragraph assesses the influence of Canadian supporting schemes on the performance of an internal combustion engine, ICE, and a Stirling Engine, SE, applied to a single-house in Ottawa (Ontario, Canada).

All the main techno-economic parameters about the microgeneration installation and the reference system are reported in Table 29 and 30.

Table 29. Techno-economic parameters of ICE unit and reference system

MICRO-CHP INSTALLATION	
Micro-CHP unit	
Technology	ICE
Max Electric power [kW_e]	1
Max Thermal power [kW_{th}]	3.2
Thermal input [kW_{th}]	5.2
Total efficiency [%]	85
Capital cost [€/kW]	8,823
ADDITIONAL HEATING BOILER	
Additional heating boiler capacity [kW]	10
Thermal efficiency [%]	92
Investment cost [€]	1,500
REFERENCE SCENARIO	
Heating boiler capacity [kW]	30
Thermal efficiency [%]	92
Investment cost	9,000

The ICE system with a top-up boiler is used to satisfy the heating demand during the winter season. It has thermal and electrical capacities of 3.2 kW_{th} and 1.2 kW_e, respectively. A single boiler with capacity of 5 kW_{th} is used to complement heating demand.

The SE has 6 kW_{th} thermal and 1 kW_e electrical capacities. The SE thermal power is able to satisfy the thermal demand of a single house without a need for a supplemental boiler as in the ICE system.

Table 30. Techno-economic parameters of Stirling engine, SE and reference system

MICRO-CHP INSTALLATION	
Micro-CHP unit	
Technology	Stirling engine
Max Electric power [kW_e]	1
Max Thermal power [kW_{th}]	6
Thermal input [kW_{th}]	9.2
Total efficiency[%]	77
Capital cost [€/kW]	6,620
REFERENCE SCENARIO	
Heating boiler capacity [kW]	30
Thermal efficiency [%]	92
Investment cost	9,000

A brief description of support mechanisms currently available in Ontario for microgeneration systems are:

- Subsidy programs:
  - A fixed price (feed-in tariff) Standard Offer Program is established in Ontario for small renewable energy generation projects. The main goal of this program is to make it more cost effective and easier for businesses to sell renewable power to the provincial grid.
  - Ontario is moving ahead with its clean energy program, taking immediate steps to ensure the long-term sustainability of renewable energy. Reducing prices - for solar projects by more than 20 per cent and wind projects by approximately 15 per cent.
  - Natural Resources Canada (NRCan) administrates the ecoENERGY for Renewable Heat program and it provides $36 million over four years to increase the adoption of solar thermal and earth energy technologies for water heating and space heating and cooling.
  - Homeowners using solar water heaters are eligible for financial support under the Eco-Energy Retrofit Home Improvement Program.
- Green homes program which provides grants:
  - Up to $5,000 to help offset up to ½ the cost of conducting a walk-through energy audit.
  - Up to $30,000 per project to help to start implementing measures to save energy and operating costs
  - For condensing equipment with > 90% efficiency
- Loans and tax incentives program:
  - New housing initiatives, coupled with regional programs are managed by NRCan to form the basis for many provincial and utility incentives and grants that are available to encourage energy efficiency in new home construction throughout the country. Also, there is Tax Incentives for Business Investments in Energy Conservation and Renewable Energy. Recently, the Canadian government decided to remove the size restrictions for PV systems that qualify for these incentives and the restrictions on the type of applications for solar air and water heating systems.

- Feed-in tariff scheme:
  - Tariffs varies on the basis of sources (e.g. solar, biogas, water), system typology and power output.

The ICE and SE under analysis can take advantage of a subsidy to cover the capital investment of, respectively, 1000 € and 700 €.

Baseline Performance Assessment

In order to assess benefits coming from microgeneration, the power devices have been compared to a reference case (separate energy production),in which the heating demand is satisfied by a condensing boiler and the electricity demand is satisfied buying electricity from the grid. Table 31 shows the main techno-economic parameters used in the study.

Table 31. Technical and economic parameters used in the study

	Parameter
PE factor for electricity [kWh_PE/kWh]	2.6
PE factor for NG [kWh_PE/kWh]	1.1
CO_2 factor for NG [g/kWh]	235
CO_2 factor for electricity [g/kWh]	590
Electricity purchasing price [€/kWh]	0.05
Feed in tariff to grid [€/kWh]	0.038
NG price [€/kWh]	0.016

Tables 32 and 33 show results without incentives. The ICE installation provides a low reduction in the energy bill (0.4%), although a 8% reduction in primary energy consumption and 9% reduction in carbon dioxide emission can be guaranteed.

Table 32. Results without incentives for ICE system.

	ICE	Reference scenario	Δ
Total cost [€/y]	2,413	2,019	20%
Saldo [€/y] (Tot cost – revenues)	2,251	2,019	11%
Operating cost [€/y]	1,541	1,385	11%
Energy bill [€/y] (Op cost – revenues)	1,379	1,385	-0.4%
PE [MWh_PE/y]	49.1	53.3	-8%
CO_2 [tCO_2/y]	10.6	11.7	-9%
CO_2 abatement costs [€/t]	204.5		
PE abatement costs [€/MWh]	54.3		
SPB	>55		

Close to 50% of the electricity generated by the ICE is used for non-HVAC electricity load with the other 50% exported to the grid.

The introduction of a SE unit, although provide a reduction in the energy bill of 15%, entails an increase in both primary energy consumption and CO_2 emissions.

Table 33. Results without incentives for SE system.

	SE	Reference scenario	Δ
Total cost [€/y]	1,861	2,019	-8%
Saldo [€/y] (Cost – revenues)	1,751	2,019	-13%
Operating cost [€/y]	1,286	1,385	-7%
Energy bill [€/y] (Op cost – revenues)	1,176	1,385	-15%
PE [MWh_PE/y]	54.7	53.3	3%
CO_2 [tCO_2/y]	11.8	11.7	1%
CO_2 abatement costs [€/t]	2,163		
PE abatement costs [€/MWh]	182		
SPB	/		

Performance assessment with support mechanism

Table 34 and 35 show the main performance parameters of microgeneration installation with incentives. As previously introduced a grant of 1000 € and 700 € have been considered for ICE and SE, respectively.

In the ICE case, although the SPB is reduced compared to the previous case, the solution continues to be not economically convenient compared to the reference system.

As regards SE, the possibility to obtain a subsidy reduces the investment cost.

Table 34. Results with incentives for ICE system.

	ICE	Reference scenario	Δ
Total cost [€/y]	2,326	2,019	15.2%
Saldo [€/y] (Cost – revenues)	2,164	2,019	7.2%
Operating cost [€/y]	1,541	1,385	11.2%
Energy bill [[€/y]	1,379	1,385	-0.4%
PE [MWh_PE/y]	49.1	53.3	-7.9%
CO_2 [tCO_2/y]	10.6	11.7	-9.4%
CO_2 abatement costs [€/t]	127.9		
PE abatement costs [€/MWh]	33.9		
SPB	51		

Table 35. Results with incentives for SE system.

	SE	Reference scenario	Δ
Total cost [€/y]	1,800	2,019	-11%
Saldo [€/y] (Cost – revenues)	1,690	2,019	-16%
Operating cost [€/y]	1,286	1,385	-7%
Energy bill [[€/y]	1,176	1,385	-15%
PE [MWh_PE/y]	54.7	53.3	3%
CO_2 [tCO_2/y]	11.8	11.7	1%
CO_2 abatement costs [€/t]	2,654		
PE abatement costs [€/MWh]	223		
SPB	/		

Discussion

Fig. 20 presents the annual total cost analysis and the CO_2 emission of the ICE system during the winter season to provide the demand heating load for the house in Ottawa (Canada).

The results show that the effect of the incentive is not significant on annual total cost of ICE compared to the one without incentive. Moreover, the ICE has higher cost compared to the reference case as the capital cost of the ICE and small boiler are high, as shown in Fig. 13 on left. On the other hand, the ICE system has less CO_2 emission compared to the reference case, as shown in Fig. 13 on the right.

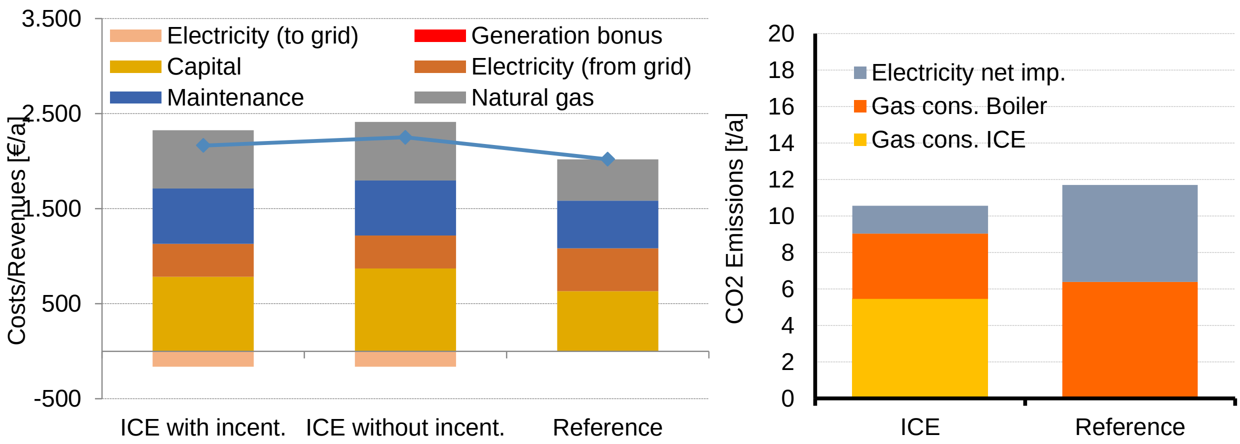


Fig.13 Total cost revenues and CO_2 emission of ICE for house case study for the heating season with and without incentive compared to reference case in Ottawa (Canada).

Fig. 14 illustrates the annual cost and CO_2 emission analysis of SE system and reference system while providing heat to a house under Ottawa weather conditions.

Analysis showed that the SE system total annual cost and CO_2 emission is less compared to the reference case, as shown in Fig. 14. However, the current incentive has a small effect on the total annual cost.

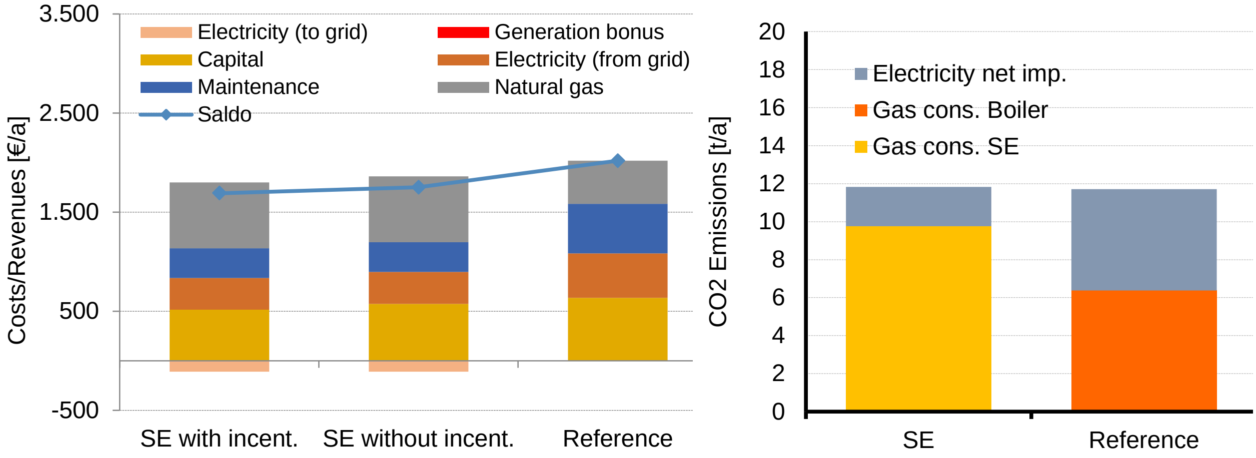


Fig.14 Total cost revenues and CO_2 emission of SE for house case study for the heating season with and without incentive compared to reference case in Ottawa (Canada).

2.4.3 Case 3

Introduction

The present study discusses the effect of Canadian incentives on two hybrid renewable energy system in load sharing applications. The two systems analysed are made up of a GSHP coupled to a fuel cell and a GSHP coupled to a PVT system, and satisfy the combined energy demand of a house and an office.

It is worthy of note that the work has been conducted in cooperation with Korea, and that the same systems have been applied considering the Korean climate conditions (see Case 3.6.2).

The main techno-economic parameters of the systems under analysis and the reference system, used to assess the system performances, are shown in Table 36 and 37.

Table 36. Techno-economic parameters of GSHP and fuel cell installation

HYBRID RENEWABLE SYSTEM	
Hybrid unit	
Technology	Fuel cell + GSHP
Max Electric power [kW_e]	1
Max Thermal power [kW_{th}] (GSHP+Fuel cell)	19.10
Thermal input [kW_{th}]	3.13
Nominal cooling power (GSHP) [kW_{cool}]	10.56
Total efficiency	159%
Capital cost [€/kW]	29,400
REFERENCE SCENARIO	
Heating boiler capacity [kW]	60
Thermal efficiency [%]	92

Table 37. Techno-economic parameters of GSHP and PVT installation

HYBRID RENEWABLE SYSTEM	
Hybrid unit	
Technology	GSHP + PVT
Max Electric power [kWe]	17.7
Max Thermal power [kW_{th}]	109.7
Thermal input [kW_{th}]	0.0023
Nominal cooling power (GSHP) [kW_{cool}]	10.5
Total efficiency	342%
Capital cost [€/kW]	101,135
REFERENCE SCENARIO	
Heating boiler capacity [kW]	60
Thermal efficiency [%]	92

In order to outline the advantages coming from the hybrid systems investigated and load sharing applications, seven cases have been analysed, as described as follows:

1. *Case one* - single residential building - conventional setup - boiler and chiller to meet heating and cooling demands of a single detached house
2. *Case two* - office building -conventional setup - boiler and chiller to meet heating and cooling demands of a office building
3. *Case three* - sum of case one and case two - conventional setup - boiler and chiller to meet heating and cooling demands of the energy needs of both the combined loads, single detached house and office
4. *Case four*-load sharing setup- using a single common unit of boiler and chiller to meet the combined loads

5. *Case five* -load sharing setup using a Ground Source Heat Pump, GSHP, to meet the combined loads
6. *Case six*- load sharing with hybrid energy system of Ground Source Heat Pump, GSHP, and Fuel Cell
7. *Case seven*- load sharing with the hybrid energy system of Ground Source Heat Pump, GSHP, and PhotoVoltaic Thermal, PVT, device.

TRNSYSand EnergyPlus have been used to assess building performance, and specific models have been developed in order to simulate the devices considered in the analysis. For detailed information about the models developed readers should refer to [33].

As introduced in the previous paragraph 3.4.2, Ontario Government supports microgeneration installation through subsidies programs, loans and a feed in tariff scheme.

The hybrid system made up of a GSHP coupled to a PVT system can take advantage of a subsidy to cover the investment cost of €2,960. In Ontario there is no subsidy for FC-GSHP system.

Baseline Performance Assessment

The annual energy consumption in kWh/yrof the seven scenarios under Ottawa weather conditions are presented in Table 38. The natural gas is used by the boiler for cases 1-4 and by the auxiliary burner in the hot water storage tank for cases 5-7 and for the FC unit in case 6. The electricity is used for space cooling in all case studies using chiller for cases 1-4 and GSHP system for cases 5-7. In addition, other electricity consumption is used by blower fans, pumps and non-HVAC (for lighting, equipment and appliances).

Table 38. Annual energy consumption for case studies in Ottawa.

Energy Use (kWh/yr) Ottawa		Case 1 (House)	Case 2 (Office)	Case 3 (Reference)	Case 4	Case 5	Case 6	Case 7
Space Heating + DHW Heating	Natural Gas	27,169	21,118	48,287	46,661	1,779	22,450	225
	Electricity	-	-	-	-	12,150	11,199	11663
Space Cooling	Electricity	2,510	3,820	6,330	5,429	2,531	2,537	2535
Non HVAC (lighting, equip., etc.)		8,001	10,401	18,402	18,402	18,402	18,402	18,402
Fans		1,189	1,519	2,703	2,679	2,996	2,990	2987
Pumps		298	241	539	531	2,055	1,944	2180
Electricity Production		0	0	0	0	0	-8760	-8690
Total (Net) End Use		39,162	37,098	76,260	73,701	39,913	50,763	29302
Energy Saving					2,559	36,347	25,497	46958
Energy Saving (%)					3.4%	47.7%	33.4%	61.6%

Table 38 presents the overall energy saving for load sharing cases studies (cases 4-7) compared to case 3 (a simple sum of the house and office) using Eq.1 under city weather conditions. The results show that the PVT-GSHP system provides the highest overall energy saving with value of 61.6% in Ottawa (Canada) followed by GSHP system (47.7%) then FC-GSHP system (33.4%). The conventional system (case 4) has the lowest overall energy saving among load sharing case studies with value of 3.4% in Ottawa.

$$Overall\ Energy\ Saving\ (\%) = 100 \cdot \left(1 - \frac{\sum(Net\ Energy\ Consumption)_{case*}}{\sum(Net\ Energy\ Consumption)_{case3}}\right) \quad (1)$$

Fig. 15 presents the total energy consumption and production intensities for the seven systems in Ottawa. The energy consumption is categorized into natural gas and electrical energies for space heating, electrical energy for space cooling, HVAC electricity and non-HVAC electricity usages. Whereas, the electricity production intensities are shown in negative values in the figures for cases 6 and 7.The results show that the PVT-GSHP system (case 7) has the lowest total energy consumption, of 72 kWh/m^2in Ottawa (Canada). The total energy consumption of the FC-GSHP system (Case 6) is significantly higher than that of the GSHP system with value of 125 kWh/m^2. This is mainly resulted from the natural gas usage increase for FC electricity production. However, the microgeneration system is able to generate electricity at the point of use and reduce the system dependency on the grid.

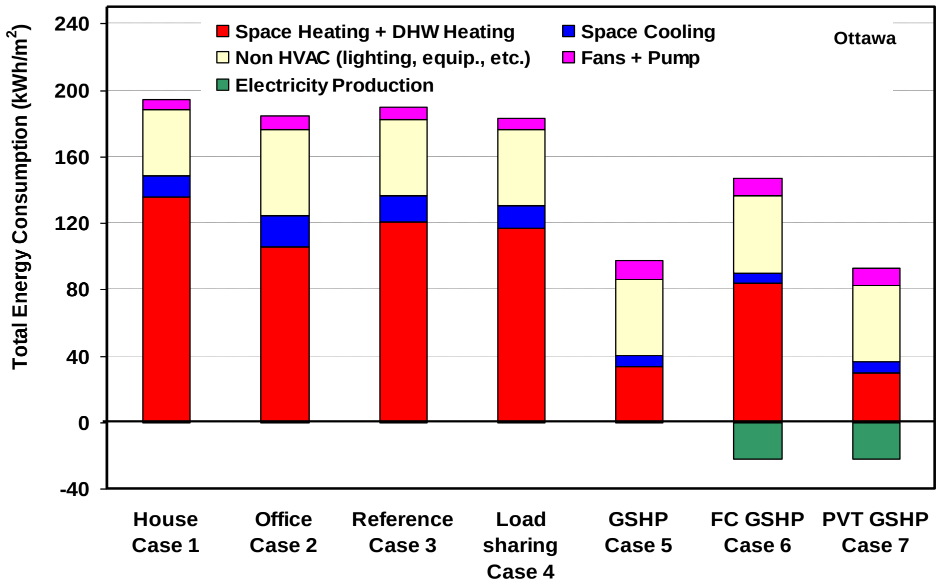


Fig.15 Total energy consumption/production intensity for case studies in Ottawa (Canada).

Fig. 16 presents the CO_2 emission from the renewable integrated case studies (cases 6-7) and reference case (case 3) in Ottawa. The results showed that the PVT-GSHP system produces the lowest CO2 emission with value of 17.2 t/y in Ottawa compared to the conventional and the FC-GSHP systems. The CO_2 emission is increased due to high electrical and natural gas consumptions for space and DHW heating in Ottawa. Moreover, the CO_2-emission produces due to import electricity from the grid (28 MWh/y).

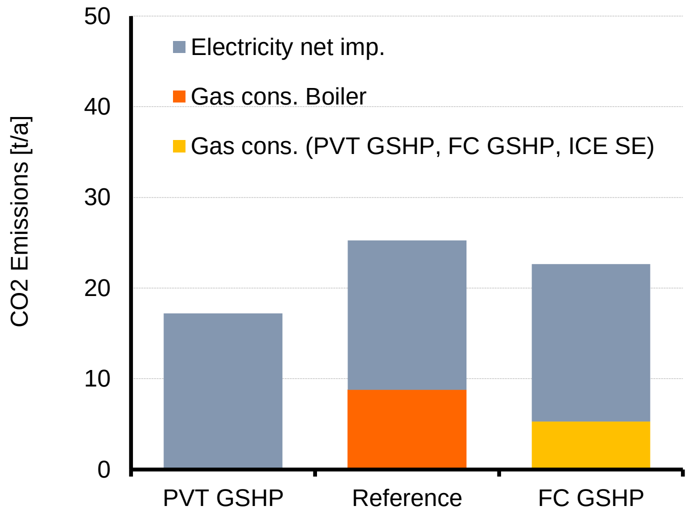


Fig.16 CO_2 emission for PVT-GSHP, FC-GSHP and reference system (Cases 6,7 and 3) in Ottawa (Canada).

Table 39 and 40 show the main results without incentives.

Table 39. Results without incentives for GSHP and fuel cell installation

	GSHP+FC	Reference scenario	Δ
Total cost [€/y]	4,326	4,266	1.4%
Saldo [€/y] (Cost – revenues)	4,326	4,266	1.4%
Operating cost [€/y]	2,257	2,913	-22.5%
PE [MWh_PE/y]	101.2	113.7	-11.0%
CO_2 [tCO_2/y]	22.6	25.3	-10.7%
CO_2 abatement costs [€/t]	23		
PE abatement costs [€/MWh]	4.8		
SPB	15.5		

Table 40. Results without incentives for GSHP and PVT system

	GSHP+PVT	Reference scenario	Δ
Total cost [€/y]	8,686	4,266	104%
Saldo [€/y] (Cost – revenues)	8,686	4,266	104%
Operating cost [€/y]	1,640	2,913	-44%
PE [MWh_PE/y]	75.8	113.7	-33%
CO_2 [tCO_2/y]	17.2	25.3	-32%
CO_2 abatement costs [€/t]	548.0		
PE abatement costs [€/MWh]	116.3		
SPB	63		

Performance assessment with support mechanism

Table 41 shows results for the GSHP combined with a PVT system, since in Ontario there is no supporting scheme for the GSHP coupled to the FC.

Table 41. Results with incentives for GSHP with PVT system

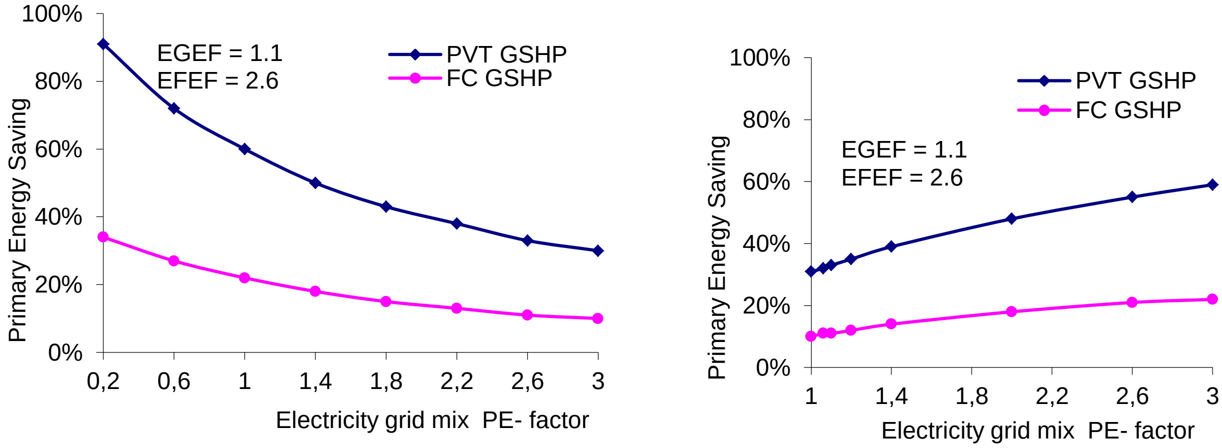
	GSHP+PVT	Reference scenario	Δ
Total cost [€/y]	8,510.0	4,266.0	99.5%
Saldo [€/y] (Cost – revenues)	8,477.0	4,266.0	98.7%
Operating cost [€/y]	1,672.0	2,913.0	-42.6%
PE [MWh_PE/y]	75.8	113.7	-33%
CO_2 [tCO_2/y]	17.2	25.3	-32%
CO_2 abatement costs [€/t]	522.1		
PE abatement costs [€/MWh]	111.0		
SPB	61.2		

Discussion

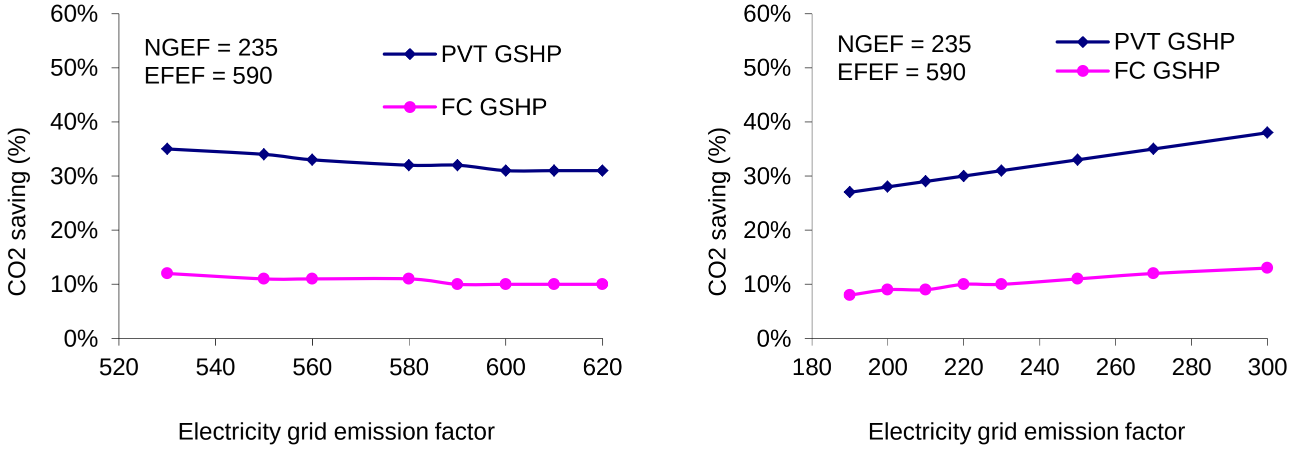
Table 42 presents the total cost per year of the hybrid systems (cases 6 and 7) with and without incentive compared to the reference case study (case 3) in Ottawa (Canada). In addition, the PVT-GSHP system has the highest capital cost and the lowest maintenance cost followed by the FC-GSHP system. However, the conventional system has the lowest capital cost and the highest maintenance and natural gas costs. The electricity price in Ottawa is high thus the electrical cost increases. According to the government subsidies policy for renewable energy, the PVT-GSHP has a small effect on the total cost.

Table 42.Total cost per year of the hybrid systems with and without incentive compared to the reference case study

System		PVT GSHP		Reference	FC GSHP	
Costs		with incent. (PVT GSHP)	without incent. (PVT GSHP)		with incent. (FC GSHP)	without incent. (FC GSHP)
Capital	€/a	6,837	7,046	1,353	2,069	2,069
Maintenance	€/a	180	180	930	438	438
Natural gas	€/a	4	4	593	357	357
Electricity (from grid)	€/a	1,488	1,488	1,390	1,463	1,463
Sum costs	€/a	8,510	8,718	4,266	4,326	4,326
Revenues						
Electricity (to grid)	€/a	-32	-32	0	0	0
Generation bonus	€/a	0	0	0	0	0
Sum Revenues	€/a	-32	-32	0	0	0
Saldo	**€/a**	**8,477**	**8,686**	**4,266**	**4,326**	**4,326**
Delta to reference	€/a	4,211	4,419	0	60	60



a)



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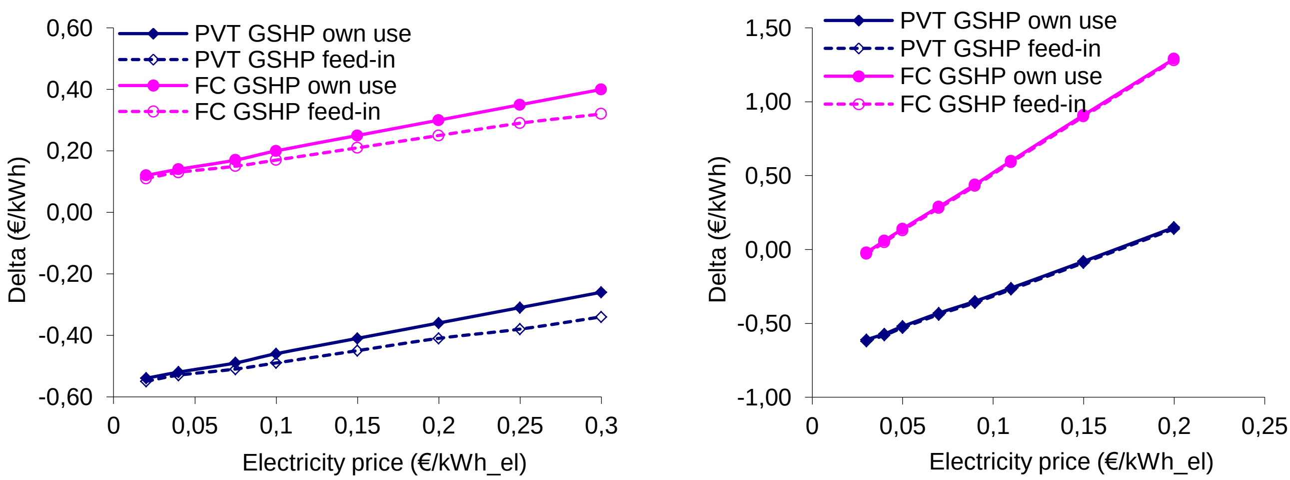

c)

Fig.17 Primary energy saving, CO_2 emission saving and delta as a function of natural gas power energy factor (NGEF), natural gas and electricity emission factors and natural gas and electricity prices in Ottawa.

A sensitivity analysis for assessing the influence of primary energy factor has been developed. Fig. 17a presents effect of natural gas PE factor (NGEF) on primary energy saving for PVT-GSHP and FC-GSHP systems with respect to the reference case. The NGEF is varied from 0.2 to 3 for electricity feed energy factor (EFEF) of 2.6 and electricity grid mix PE- factor (EGEF) of 1.1 and 2.6. The results show that there is no significant effect of NGEF on the primary energy saving for FC-GSHP system at the two values of EGEF (1.1 and 2.6). However, it is decreased from 91% to 30% with further increase in NGEF for PVT-GSHP system at EGEF = 1.1 (Fig.17a on left). At high EGEF = 2.6, the primary energy saving increases with further increase in the NGEF, as shown in Fig.17a on right.

Table 43. Sensitivity analysis of subsidy value on annual system and CO_2 emission saving costs for hybrid case studies and reference case (Ottawa).

PVT-GSHP							Reference case	FC-GSHP					
Capital cost (€)	Subsidy %	Subsidy value (€)	Cost/Revenues (€/a)	CO_2 saving (t/a)	Cost of CO_2 saving (€/a)	CO_2 cost (€/a)	Cost/Revenues (€/a)	Capital cost (€)	Subsidy %	Subsidy value (€)	Cost/Revenues (€/a)	CO_2 saving (t/a)	Cost of CO_2 saving (€/a)
100,135	0%	0	8,718	8.1	169.3	20.9	4266	29,400	0.0%	0	4326	2.7	56.4
100,135	1%	751.01	8,648					29,400	0.1%	29.4	4,324		
100,135	5%	5006.8	8,366					29,400	0.2%	58.8	4,322		
100,135	10%	10014	8,013					29,400	0.6%	176.4	4,314		
100,135	15%	15020	7,661					29,400	1.0%	294	4,306		
100,135	20%	20027	7,309					29,400	2.0%	588	4,285		
100,135	25%	25034	6,957					29,400	6.0%	1764	4,202		
100,135	30%	30041	6,604					29,400	10.0%	2940	4,119		
100,135	35%	35047	6,252					29,400	15.0%	4410	4,016		
100,135	40%	40054	5,900					29,400	20.0%	5880	3,913		
100,135	45%	45061	5,548					29,400	30.0%	8820	3,706		
100,135	50%	50068	5,195					29,400	40.0%	11760	3,499		
								29,400	50.0%	14700	3,292		

On the other hand, the CO_2 saving increases slightly for FC-GSHP system and increases significantly for PVT-GSHP system with further increase in natural gas emission factor, as shown in Fig.17b on right. However, there is no significant effect of electricity grid emission factor on CO_2 saving for both systems (Fig.17b on left).

Moreover, Fig.17c displays the effect of natural and electricity gas prices on difference in the price of purchase electricity and own use/feed in the PVT-GSHP or FC-GSHP system (delta) in €/kWh. The results show that the delta increases with further increase in natural gas price, as shown in Fig.17c on right. The results show also that there is no significant difference in delta between own-use and feed-in for both systems. On the other hand, both systems provide less delta for feed in compared to own use at high electricity price, as presented in Fig.17c on left.

Table 43 illustrates sensitivity analysis of the subsidy on annual system cost and CO_2 emission saving cost for the two hybrid systems under Ottawa climate conditions.

The subsidy has value of 0% to 50% from the capital cost as the government policy for subsidies is changed a cording to the system. Typically, the government provides high subsidy for the renewable system. The CO_2 saving is calculated based on the conventional system (reference case). The CO_2 emission cost is estimated to be 20.9 €/ton. From the results a high subsidy value reduces the annual system cost. In addition, the hybrid systems are providing revenues from CO_2 emission saving cost.

2.5 Flanders (Belgium)

Introduction

The work assesses the possibility to integrate a group of micro-CHP technologies in the Belgian balancing market, pointing out both advantages coming from join the market and the influence of the available supporting scheme on microgeneration performance. For further references and details on models developed, readers can refer to [34].

The virtual power plant analysed, consists of an aggregation of 13 micro-CHP devices as depicted in Table 44. The different load profiles come from measured data, available via IEA/EBC's Annex 54.

Table 44. Overview of the members of the aggregator with corresponding CHP and load profile[1]

CHP	load profile
Whispergen Stirling	house 1
Whispergen Stirling	house 2
Whispergen Stirling	house 3
Whispergen Stirling	house 4
Whispergen Stirling	house 5
Whispergen Stirling	house 6
Senertec Dachs G5.5 standard	small hotel 1
Senertec Dachs G5.5 standard	small hotel 2
Senertec Dachs G5.5 standard	small office
Senertec Dachs G5.5 standard	small greenhouse
Viessmann Vitobloc 200 EM	medium office
Viessmann Vitobloc 200 EM	medium greenhouse
Viessmann Vitobloc 200 EM	large office

Due to the limited amount of load profiles available, they were adapted to obtain a reasonable representation of a Belgian VPP.A detailed explanation of the operations performed can be found in [34]. The maximum rectangle method was used to identify the optimal size of the micro-CHP units; the procedure is illustrated in Fig.18.

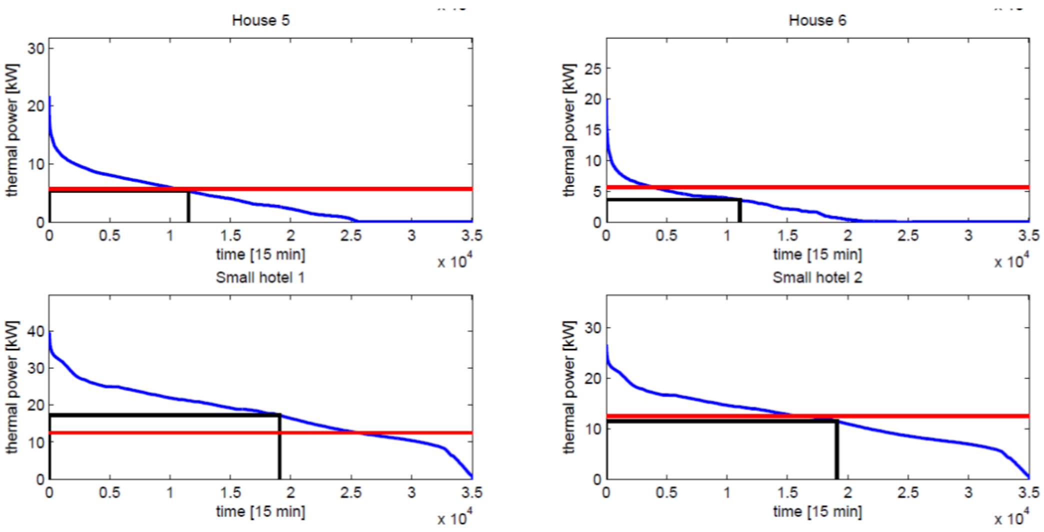

Fig.18 Load duration diagrams are plotted blue, largest rectangle in black and the corresponding maximum thermal CHP output in red

A thermal load duration diagram is plotted. Afterwards, the biggest rectangle that can be inscribed under the load-duration curve is determined. The intersection between the rectangle and the vertical axes corresponds to the optimal thermal capacity for the micro-CHP device.

The main characteristics of micro-CHP units applied are reported in Table 45.

Table 45. Techno-economic parameters of micro-CHP installation.

MICROGENERATION INSTALLATION				
MICRO-CHP UNIT				
Manufacturer	Whispergen Stirling	Senertec Dachs G5.5 standard	Viessman Vitobloc 200EM-18/36	Viessman Vitobloc 200EM-50/81
Power output [kW$_e$]	1.0	5.5	9-18	25-50
Thermal output [kW$_{th}$]	5.7	12.5	26-36	46-81
Electrical efficiency [%]	12.0	27.0	24-32	29-34
Thermal efficiency [%]	79.0	61.0	64-70	53-55
ADDITIONAL HEATING BOILER				
Capacity [kW]	10.5-30			
Thermal efficiency [%]	90			
STORAGE TANK				
Thermal efficiency [%]	99.8			

In order to assess advantages deriving from enter the balance market a mixed integer linear programming, MILP, model was developed and solved making use of CPLEX and the commercial software GAMS.

The optimization is performed in two stages, in the first stage a day-ahead optimization decides the optimal bids for the DA-market, on the basis of the spot market prices and heat demand, which are assumed to be known. The objective is to meet the thermal load at the minimum cost.

In the second stage or in other words during real time, the actual output of the aggregator is set. This output can differ from the scheduled day ahead in order to help the Balance Responsible Party (BRP) to which it belongs to reduce the total imbalance cost.

As regards supporting scheme for microgeneration in Flanders, eligible micro-CHP units can take advantage of CHP certificates [35].

The amount of certificates depends on different factors such as, for instance, the primary energy savings and technology employed. An overview of the amount of certificates per hour for the micro-CHP units applied is presented in Table 46. In general it is expressed as a linear function of the amount of produced electric power.

Although the price for CHP certificates derives from market negotiations, this work considers a constant price of 31 €, which is the minimum value guaranteed by the legislation[3]. In general the certificates are granted for a period of 10 years.

For the present study it has been assumed that all the units are entitled to receive the governmental support.

Table 46. Amount of certificates per hour for the different CHP expressed as a linear function

	N° of certificates/hour=$a_{cert}*P_{el}+b_{cert}$	
	a_{cert}	b_{cert}
Whispergen Stirling	0.00098	0
Senertec Dachs G5.5 Standard	0.0008	0
Viessman vitobloc 200 EM-18/36	0.0011	-0.0006
Viessman vitobloc 200 EM-50/81	0.0012	0.0152

Baseline Performance Assessment

In this section the CHP certificate scheme is not taken into account. Results coming from the simulation are summarized in Table 47.

[3] This price represents the worst case scenario and it is also recommended to use by COGEN-Vlaanderen when evaluating economic viability of CHP systems.

Table 47. Simulation results without CHP certificates.

	Summer	Autumn	Winter
Day-Ahead cost [€]	313.39	780.54	2326.3
Real Time- profits [€]	0.48	71.01	316.70
SS [€]	0.02	15.66	2.46
Total cost [€]	312.89	693.87	2007.2

An explanation of parameters is reported hereinafter:

- Day-Ahead cost [€]

  It is the cost of the scheduled micro-CHP system including fuel cost for feeding both micro-CHP and boiler, the revenues from the electricity sold to the day-ahead market and the governmental support thus:

$$DA\ cost\ [€] = Fuel\ cost\ (CHP, auxiliary\ boiler) - Electricity\ revenues\ (DA\ market) - CHP\ certificates$$

- Real Time- profits [€]

  They are calculated at every time step once the VPP is re-dispatched, profits include revenues (or expenses) from selling the electricity in the imbalance market, the difference in fuel cost and in CHP-certificates. It is worthy of note that Δfuel can take negative values e.g. negative regulation (i.e., micro-CHP is turned off but it was scheduled to be on).

$$Real\ Time\ profits\ [€] = Imbalances\ profits\ (imbalances\ price) - \Delta fuel - \Delta\ CHP\ certificates$$

- SS [€] Storage settlement

  SS is a figure that helps to account for the energy difference in the storage tank between the start and the end of the optimization problem. It is assumed that the next week will pay the current week based on the value of the heat in the storage. This value is determined by calculating the equivalent boiler fuel cost.

$$SS[€] = Imbalances\ profits\ (imbalances\ price) - \Delta fuel - \Delta\ CHP\ certificates$$

$$Total\ cost[€] = DA\ cost - Real\ Time\ profites - SS\ Storage\ settlement$$

Performance assessment with support mechanism

Table 48 shows simulation results with CHP certificates. It is remarkable that the real time profits for winter and autumn are larger without certificates. This can be explained considering that without certificates (similar to the case when the gas price increases) the motivation to schedule the CHP is lower, thus higher up-regulation is possible.

Table 48. Simulation results with CHP certificates.

	Summer	Autumn	Winter
Day-Ahead cost [€]	306.53	707,97	2067,5
Real Time- profits [€]	15,82	20,14	48,9
SS [€]	1.63	13.06	4.30
Total cost [€]	289.08	674.78	2014.3

On the other hand when the certificates are obtained, down-regulation is less attractive (recall the amount of certificates depend on the electricity production of the CHP). Nevertheless, without certificates the amount of down-regulation does not increase, this is because less CHP are scheduled and consequently less down-regulation is possible.

Fig.19 shows the yearly cost/profits with and without certificate, deriving from the sum of the three modelled weeks. In general it can be said that using the real time approach leads to larger profits than only using the D-A schedule. Results of the imbalance reduction technique are summarized in [36]. It can be seen that the difference in the total cost is almost negligible.

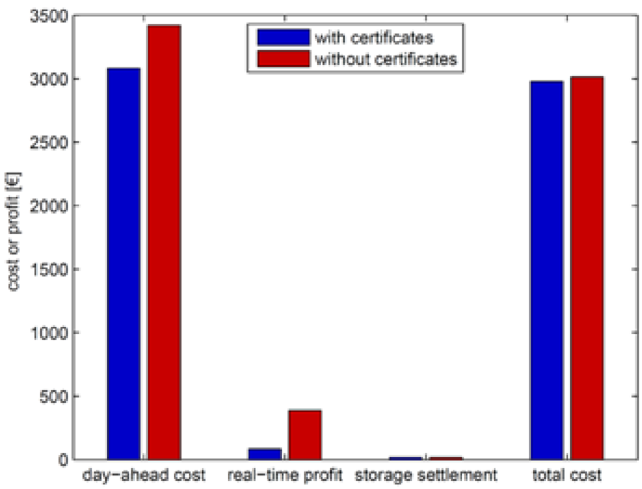

Fig.19: Different cost components with and without certificates

Discussion

The analysis presented above investigates the possibility to integrate a group of micro-CHP devices in the Belgian balancing market by passive balancing. It has been assumed that all of micro-CHP devices receive the governmental support known as 'CHP certificates'.

It was shown that revenues coming from CHP certificates increase the motivation to schedule the micro-CHP during the D-A negotiations and decrease the willingness to perform downward-regulation. Additionally, larger real-time profits can be achieved in winter and autumn when no certificates are present, due to the large demand for up-regulation in these weeks.

However (and different than expected) in absence of certificates, the total cost increases only 1.16%. This could imply that even without support mechanism, entering the balancing market could be profitable. Nevertheless solid conclusions could only be stated when simulations are conducted for a longer period.

Additionally, a sensitivity analysis was performed to assess the influence of gas price and storage capacity.

Gas price

In the base model the gas price was assumed to be 0.0524 €/kWh. In order to evaluate the influence of this parameter, simulations were performed with a lower price and higher price of respectively, 0.04 €/kWh and 0.07 €/kWh. The results are depicted in Fig. 20 and Fig. 21. Fig. 20 shows the different cost components of the aggregators (real time profits are considered as negative cost). As expected, the D-A cost (blue bars) increases when the gas price increases since the cost for meeting the heat demand rises.

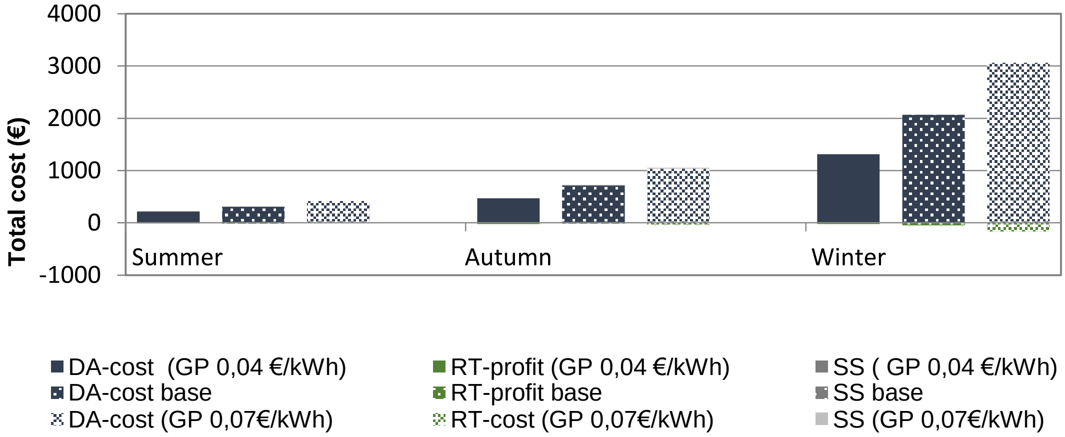

Fig.20: Cost components with different gas prices. The real time profits are considered negative costs.

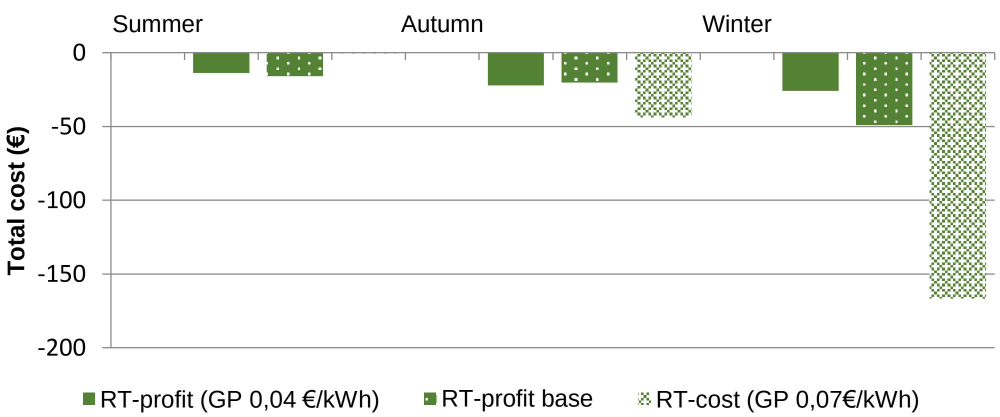

Fig.2: Closer look at real time profits. Larger RT profits can be seen at higher gas price since more upward regulation is possible.

Nevertheless, when looking at Fig.21 it is remarkable that the increase in the gas price leads to an increase in RT- profits especially in winter. This is due to the fact that when the price rises, the CHPs are less scheduled, thus D-A schedule increases the opportunities for up-regulation that is largely required in winter.

Storage capacity

In order to assess the influence of storage capacity, a sensitivity study was performed. In the base case the capacity of the storage tank was designed to be able to store two hours of maximal thermal CHP power, for this analysis the capacity was varied and the results can be observed in Fig. 22.

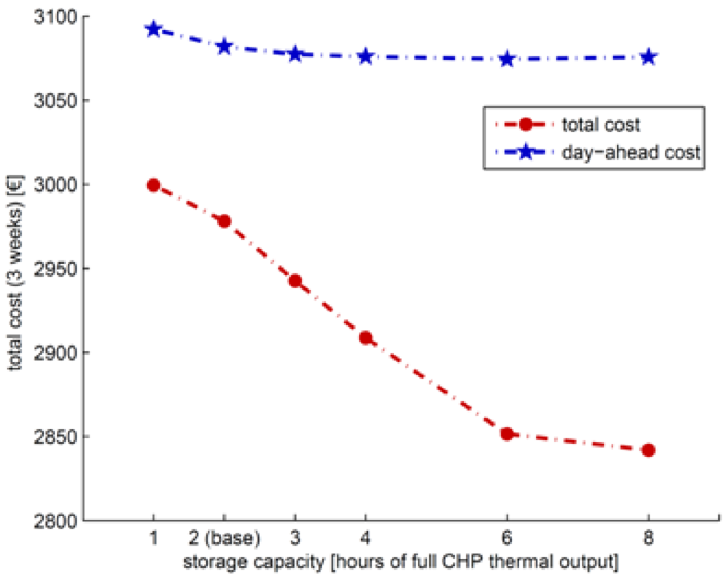

Fig.22 Total cost vs storage capacity.

When the storage capacity is larger than the maximum thermal power recovered in 2h of micro-CHP operation, the D-A cost reaches a stable value. On the contrary the total cost keeps on decreasing due to the increase in R-T profits. This means that a larger storage leaves more flexibility for imbalance reduction. Nonetheless it is important to keep in mind that the investment cost and the available space are the real constraints for storage capacity.

2.6 Korea

Introduction

The present work deals with the assessment of the influence of Korean support schemes on the performances of two case studies:

- Case 1 assesses the introduction of an Internal Combustion Engine, ICE, and a Stirling engine, SE in a detached house
- Case 2 discusses two renewable hybrid systems in load sharing applications, which means, for the case under analysis, satisfying the combined energy needs of a single house and an office building [37].

It is worthy of note that this study is the result of collaboration between Canadian and Korean researchers[4]. The micro-CHP and hybrid renewable energy cases have been investigated considering both the weather condition of Canada and Korea.

2.6.1 Case 1

An ICE and a SE system have been applied to satisfy the energy demand of a house in Incheon (Korea), with a heat and electrical need of 17,000 and 8,000 kWh, respectively.

The ICE system with a top up boiler is utilized to satisfy the heating demand during the winter season. The ICE system has thermal and electrical capacities of 3.2 kW_{th} and 1.2 kW_e, respectively. A single boiler with capacity of 5 kW is used to complement heating demand.

The SE has 6 kW thermal and 1 kW_e electrical capacities. The SE thermal power is able to satisfy the thermal demand of a single house without a need for a supplemental boiler as in the ICE system.

As discussed in the previous case studies the energy and economic assessment of the cogeneration concept required comparison of its performances to that related to separate production (reference case). Table 49 and 50 show the main technical and economic parameters of the systems under analysis and the reference system.

As regards to the Korean incentives, at the time of writing there was a government subsidy program to provide up to 50% of the installation costs, depending upon the technology type. For the applications under analysis, a contribution of 1000€ and 500€, for the ICE and Stirling engine respectively, have been included.

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[4] CanmetENERGY Research Centre and Korea Institute for Energy Research (KIER) have activated a joint project to research micro-generation systems applications in stand-alone and load sharing applications.

Table 49. Techno-economic parameters of ICE unit and reference system

MICRO-CHP INSTALLATION	
Hybrid unit	
Technology	ICE
Max Electric power [kW_e]	1.2
Max Thermal power [kW_{th}]	3.2
Thermal input [kW_{th}]	5
Total efficiency	85%
Capital cost [€/kW]	8,823
ADDITIONAL HEATING BOILER	
Additional heating boiler capacity [kW]	5
Thermal efficiency [%]	92
Investment cost [€]	1,500
REFERENCE SCENARIO	
Heating boiler capacity [kW]	30
Thermal efficiency [%]	92
Investment cost [€]	9,000

Table 50. Techno-economic parameters of Stirling engine, SE and reference system

HYBRID RENEWABLE SYSTEM	
Hybrid unit	
Technology	Stirling engine
Max Electric power [kWe]	1
Max Thermal power [kW_{th}]	6
Thermal input [kW_{th}]	9.2
Total efficiency	77%
Capital cost [€/kW]	6,620
REFERENCE SCENARIO	
Heating boiler capacity [kW]	30
Thermal efficiency [%]	92

Baseline Performance Assessment

In order to assess the performances of microgeneration systems, as in the previous case studies, they have been compared to a reference case (separate production) consisting of satisfying the heating demand by a condensing boiler and the electricity demand buying energy from the grid.

Table 51 and 52 show results for ICE and SE installation without incentives. The ICE installation is not economically convenient although interesting primary energy and carbon dioxide emission reductions can be provided. The introduction of SE, although requires a lower investment than standard production provide higher operating costs and primary energy consumption.

The ICE system provides part of electrical load with the rest imported from the grids. About 50% of electricity generation by ICE is used for non-HVAC electricity load with the other 50% exported to the grid.

Table 51. Results without incentives for ICE system.

	ICE	Reference scenario	Δ
Total cost [€/y]	3,003	2,258	33%
Saldo [€/y] (Cost – revenues)	2,873	2,258	27%
Operating cost [€/y]	2’131	1,625	31%
PE [MWh_PE/y]	36.9	43.1	-14%
CO_2 [tCO_2/y]	7.9	8.2	-4%
CO_2 abatement costs [€/t]	/		
PE abatement costs [€/MWh]	/		
SPB	/		

Table 52. Results without incentives for SE system.

	SE	Reference scenario	Δ
Total cost [€/y]	2,533	2,258	12%
Saldo [€/y] (Cost – revenues)	2,474	2,258	-3%
Operating cost [€/y]	1,958	1,625	29%
PE [MWh_PE/y]	45.5	43.1	6%
CO_2 [tCO_2/y]	9.4	8.2	15%
CO_2 abatement costs [€/t]	183		
PE abatement costs [€/MWh]	95.8		
SPB	/		

Performance assessment with support mechanism

Table 53 and 54 shows results with incentives.

Table 53. Results with incentives for ICE system.

	ICE	Reference scenario	Δ
Total cost [€/y]	2,916	2,258	46%
Saldo [€/y] (Cost – revenues)	2,786	2,258	23%
Operating cost [€/y]	2’131	1,625	31%
PE [MWh_PE/y]	36.9	43.1	-14%
CO_2 [tCO_2/y]	7.9	8.2	-4%
SPB	/		

Table 54. Results with incentives for SE system.

	SE	Reference scenario	Δ
Total cost [€/y]	2,489	2,258	10%
Saldo [€/y] (Cost – revenues)	2,431	2,258	8%
Operating cost [€/y]	1,958	1,625	21%
PE [MWh_PE/y]	45.4	43.1	5%
CO_2 [tCO_2/y]	9.4	8.2	15%
SPB	/		

Discussion

Fig. 23 presents the winter season total cost analysis and the CO_2 emission of the ICE system while applied to a house in Incheon (Korea). The results showed a small effect of incentives on total cost of ICE compared to the one without incentives. Moreover, the ICE has higher cost compared to the reference as the capital cost of the ICE and small boiler are high, as shown in Fig. 23 on left. The cost increases significantly in Incheon due to high gas price. On the other hand, the ICE system provides less CO_2 emission compared to the reference cases, as shown in Fig. 23. The CO_2 emission is less in Incheon due to less natural gas consumption.

Fig. 24 illustrates the annual cost and CO_2-emission analysis of SE system and reference system while providing heat to a house under Incheon (Korea) weather conditions. The analysis shows that the SE system total annual cost and CO_2-emission is lower than the reference case, as presented in Fig. 24. However, the incentive provided at the time of writing has only a small effect on the total cost. The annual operating cost is higher than standard production in Incheon due to the high gas price and low CO_2 emission due to less natural gas consumption.

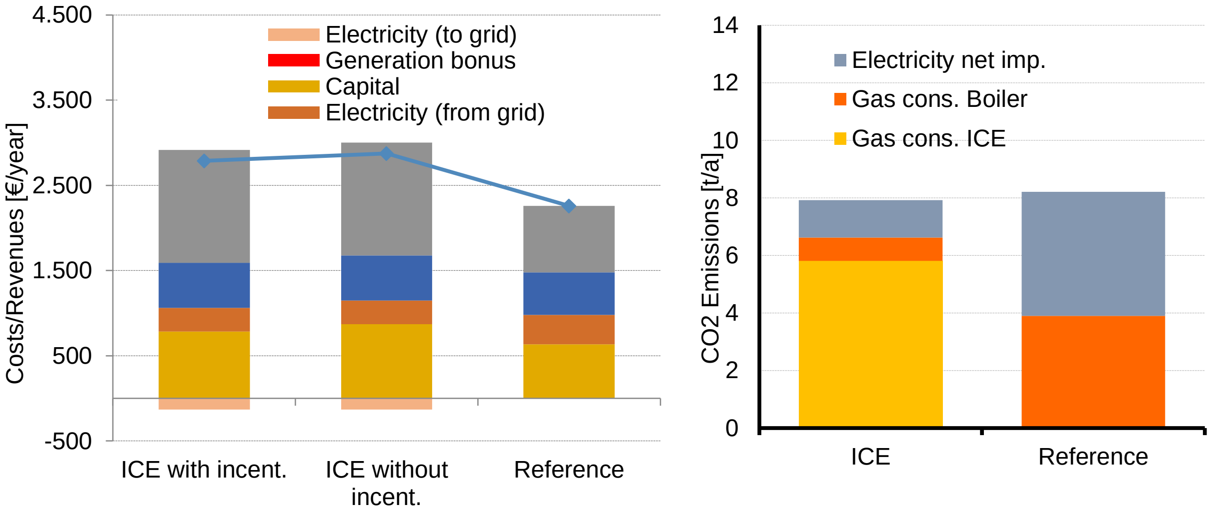


Fig.23 Total cost revenues and CO_2 emission of ICE for house case study for the heating season with and without incentive compared to reference case in Incheon (Korea).

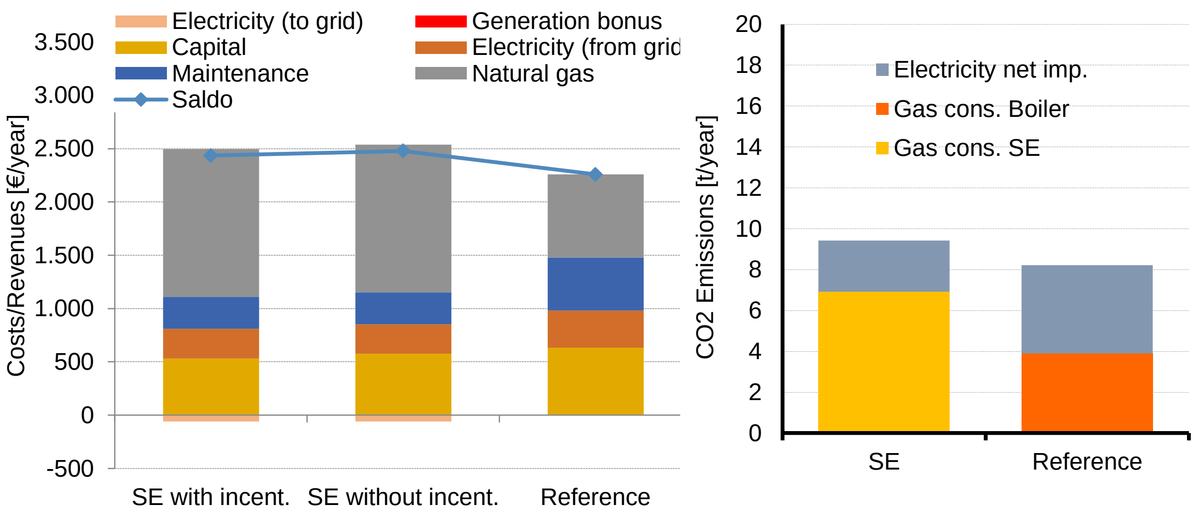


Fig.24 Total cost revenues and CO_2 emission of SE for house case study for the heating season with and without incentive compared to reference case in Incheon (Korea).

2.6.2 Case 2

Case 2 considers ground source heat pumps (GSHP)/fuel cell (FC) and GSHP/PVT hybrid systems. The main technical and economic parameters of the systems under analysis together with the reference system used to assess their performances are shown on Table 55, 56.

Table 55. Techno-economic parameters of GSHP and fuel cell (FC) installation

HYBRID RENEWABLE SYSTEM	
Hybrid unit	
Technology	Fuel cell + GSHP
Max Electric power [kWe]	1
Max Thermal power [kW_{th}] (GSHP)	17.6
Nominal cooling capacity (GSHP) [kW_{cool}]	10.6
Thermal input [kW_{th}]	3.3
Max Thermal power [kW_{th}] (Fuel cell)	1.5
Capital cost [€/kW]	29,254
REFERENCE SCENARIO	
Heating boiler capacity [kW]	60
Thermal efficiency	92%
Capital cost boiler [€]	918
Capital cost chiller [€]	2,070

Table 56. Techno-economic parameters of GSHP and PVT installation

HYBRID RENEWABLE SYSTEM	
Hybrid unit	
Technology	GSHP + PVT
Nominal thermal power GSHP (heating) [kW_{th}]	17.6
Nominal cooling capacity (GSHP) [kW_{cool}]	10.6
Nominal electrical power PVT [kW_{th}]	2.9
Nominal thermal power PVT (heating) [kW_{th}]	15.35
Electricity consumption GSHP (heating) [kW_{el}]	4.884
Electricity consumption GSHP (cooling) [kW_{el}]	2.931
Capital cost [€/kW]	30,074
REFERENCE SCENARIO	
Heating boiler capacity [kW]	60
Thermal efficiency	92%
Capital cost boiler [€]	918
Capital cost chiller [€]	2,070

In order to outline the advantages coming from the hybrid systems investigated and load sharing applications, seven cases have been analysed, as described hereinafter:

1. *Case one* - single residential building - conventional setup - boiler and chiller to meet heating and cooling demands of a single detached house
2. *Case two* - office building -conventional setup - boiler and chiller to meet heating and cooling demands of a office building

3. *Case three* - sum of case one and case two - conventional setup - boiler and chiller to meet heating and cooling demands of the energy needs of both the combined loads, single detached house and office
4. *Case four*-load sharing setup- using a single common unit of boiler and chiller to meet the combined loads
5. *Case five* -load sharing setup using a Ground Source Heat Pump, GSHP, to meet the combined loads
6. *Case six*- load sharing with hybrid energy system of Ground Source Heat Pump, GSHP, and Fuel Cell
7. *Case seven*- load sharing with the hybrid energy system of Ground Source Heat Pump, GSHP, and PhotoVoltaic Thermal, PVT, device.

TRNSYS and EnergyPlus have been used to correctly assess building performance, and specific models have been developed in order to correctly simulate the devices considered in the analysis. For detailed information about the models developed readers should refer to [37].

With regards to policy support mechanisms for microgeneration in Korea, as previously mentioned, there are government subsidy programs to provide up to 50 % initial costs [1]. For the two cases analysed a grant of 50% of the initial costs has been considered.

Baseline Performance Assessment

The annual energy consumptions in kWh/y of the seven scenarios under Incheon weather condition are presented in Table 57. The space and DHW heating is classified into electricity and natural gas. The natural gas is mainly used by the boiler for cases 1-4 and by the auxiliary burner in the hot water storage tank for cases 5-7 and for the FC unit in case 6. The electricity is used for space cooling in all case studies using chiller for cases 1-4 and GSHP system for cases 5-7. In addition, other electricity consumption is used by blower fans, pumps and non-HVAC (for lighting, equipment and appliances).

Table 57. Annual energy consumption for case studies in Incheon (Korea).

Energy Use (kWh/y) Incheon		Case 1 (House)	Case 2 (Office)	Case 3 (Reference)	Case 4 (Load sharing)	Case 5 (GSHP)	Case 6 (FC- GSHP)	Case 7 (PV-GSHP)
Space Heating + DHW Heating	Natural Gas		11,722	29,411	27,929	2,608	22,427	926
	Electricity	-	-	-	-	7,130	6,388	6,736
Space Cooling	Electricity	4,124	5,911	10,035	9,368	4,372	4,386	4,382
Non HVAC (lighting, equip., etc.)		8,001	10,401	18,402	18,402	18402	18,402	18,402
Fans		1,077	1,467	2,544	2,524	2693	2,689	2,687
Pumps		260	227	487	480	1641	1,554	1,970
Electricity consumption		13,462	18,006	31,468	30,774	34,238	33,419	34,177
Total (Net) End Use		31,152	29,728	60,879	58,703	36,846	47,086	28,062
Energy Saving					2,176	24,033	13,793	32,817
Energy Saving (%)					**3.57%**	**39.48%**	**22.66%**	**53.91%**

Moreover, Table 57 presents the overall energy saving for load sharing cases studies (cases 4-7) compared to case 3 (a simple sum of the house and office) using Eq.1 under city weather conditions.

The results show that the PVT-GSHP system provides the highest overall energy saving with value of 53.9% in Incheon followed by GSHP system (39.5%) then FC-GSHP system (22.7%). The conventional system (case 4) has the lowest overall energy saving among load sharing case studies with value of 3.5%.

$$\text{Overall Energy Savings(\%)} = 100 \cdot \left(1 - \frac{\sum(\text{Net Energy Consumption})_{case *}}{\sum(\text{Net Energy Consumption})_{case3}} \right) \quad (1)$$

Table 58 presents the total energy consumption and production intensities for the seven systems in Incheon (Korea). The energy consumption is categorized into natural gas and electrical energies for space heating, electrical energy for space cooling, HVAC electricity and non-HVAC electricity usages. Whereas, the electricity production intensities are shown in negative values in the figure for cases 6 and 7. The results show that the PVT-GSHP system (case 7) has the lowest total energy consumption, of 70.2 kWh/m^2. The total energy consumption of the FC-GSHP system (Case 6) is significantly higher than that of the GSHP system with value of 118 kWh/m^2. This is mainly resulted from the natural gas usage increase for FC electricity production. However, the microgeneration system is able to generate electricity at the point of use and reduce the system dependency on the grid.

Table 58. Energy consumption and production intensities for Incheon (Korea)

Energy Intensity (kWh/m^2-yr)		Case 1 (House)	Case 2 (Office)	Case 3 (Reference)	Case 4 (Load sharing)	Case 5 (GSHP)	Case 6 (FC- GSHP)	Case 7 (PV-GSHP)
Space Heating	**Natural Gas**	88.4	58.6	73.5	69.8	6.5	56.1	2.3
DHW Heating + FC	**Electricity**	-	-	-	-	17.8	16	16.8
Space cooling	**Electricity**	20.6	29.6	25.1	23.4	10.9	11	11
Fans		5.4	7.3	6.4	6.3	6.7	6.7	6,7
Pumps		1.3	1.1	1.2	1.2	4.1	3.9	4.9
Non HVAC (lighting, equip., etc.)		40	52	46	46	46	46	46
Electricity Production		0	0	0	0	0	21,9	17.6
Total (Net) Energy Use		155.8	148.6	152.1	146.8	92.1	117.7	70.2
Energy Saving					5.4	60	34.4	82

Table 59 and 60 present system performances of the hybrid systems (cases 6 and 7) without incentive compared to the reference case study (case 3).The GSHP coupled with the FC system provides a reduction in total and operating costs in addition to a reduction in energy consumption and CO_2 emissions of 22%.

Table 59. Results without incentives for GSHP + FC system.

	GSHP+FC	Reference scenario	Δ
Total cost [€/y]	4,848	3,679	32%
Saldo [€/y] (Cost – revenues)	3,890	3,679	6%
Operating cost [€/y]	3,059	3,496	-13%
PE [MWh_PE/y]	98.65	126.76	-22%
CO_2 [tCO_2/y]	17.91	23.06	-22%
CO_2 abatement costs [€/t]	41		
PE abatement costs [€/MWh]	7.49		
SPB	18.82		

The GSHP coupled with the PVT, although entails a higher investment costs, provides a very interesting reduction in both primary energy consumption and CO_2 emissions.

Table 60. Results without incentives for GSHP+PVT.

	GSHP+PVT	Reference scenario	Δ
Total cost [€/y]	3,903	3,679	6%
Saldo [€/y] (Cost – revenues)	3,133	3,679	-15%
Operating cost [€/y]	2,064	3,496	-41%
PE [MWh_PE/y]	82.43	126.76	-35%
CO_2 [tCO_2/y]	13.77	23.06	-40%
CO_2 abatement costs [€/t]	59		
PE abatement costs [€/MWh]	12.31		
SPB	12.30		

Performance assessment with support mechanism

As above-mentioned a grant of 50% of the initial costs has been included.

Tables 61 and 62 present the total cost per year of the hybrid systems (cases 6 and 7) with incentive compared to the reference case study (case 3) in Incheon (Korea).

From the results, the PVT-GSHP system provides the best result in terms of SPB, which is less than 6 years. However, the conventional system has the lowest capital cost, but the highest maintenance and natural gas costs. For the GSHP+FC case, since the natural gas price in Incheon is high, the SPB is longer.

Table 61. Results with incentives for GSHP+FC system.

	GSHP+FC	Reference scenario	Δ
Total cost [€/y]	3,953	3,679	7%
Saldo [€/y] (Cost – revenues)	2,995	3,679	-38%
Operating cost [€/y]	3,059	3,496	-13%
PE [MWh_PE/y]	98.65	126.76	-22%
CO_2 [tCO_2/y]	17.91	23.06	-22%
SPB	8.34		

Table 62. Results with incentives for GSHP+PVT system.

	GSHP+PVT	Reference scenario	Δ
Total cost [€/y]	2,984	3,679	-19%
Saldo [€/y] (Cost – revenues)	2,214	3,679	-40%
Operating cost [€/y]	2,064	3,496	-41%
PE [MWh_PE/y]	82.43	126.76	-35%
CO_2 [tCO_2/y]	13.77	23.06	-40%
SPB	5.47		

Discussion

Fig. 25 presents the CO_2 emission from the renewable integrated case studies (cases 6-7) and reference case (case 3) in Incheon (Korea).

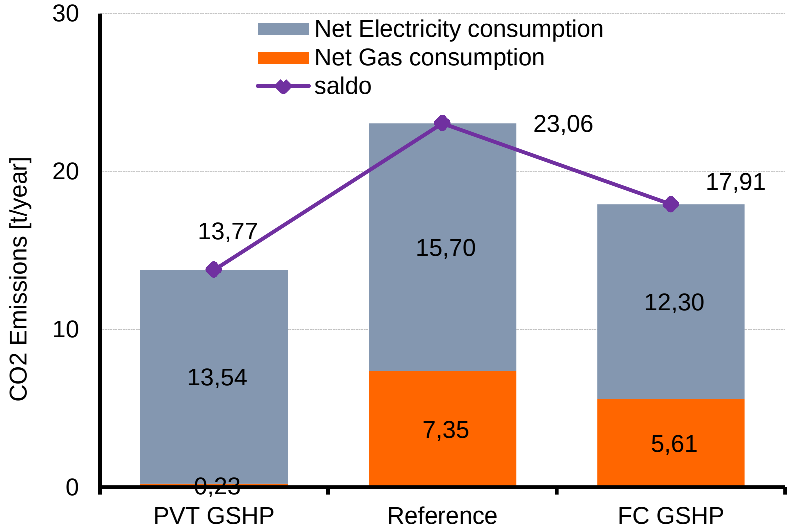


Fig.25 CO_2 emission for case studies in Incheon.

The results show that the PVT-GSHP system produces the lowest CO_2 emission with value of 13.7 t/y compared to the conventional and the FC-GSHP systems. The CO_2 emission increases for the reference case as the imported electricity from the grid is high (31.5 MWh/y).

Fig. 26a presents the effect of natural gas PE factor (NGEF) on primary energy saving for the hybrid PVT-GSHP and FC-GSHP systems with respect to the reference case. The NGEF is varied from 0.2 to 3 for electricity feed energy factor (EFEF) of 2.6 and electricity grid mix PE- factor (EGEF) of 1.1 and 2.6. The results showed that there is no significant effect of NGEF on the primary energy saving for FC-GSHP system at the two values of EGEF (1.1 and 2.6). However, it is decreased from 90% to 41% with further increase in NGEF for PVT-GSHP system at EGEF = 1.1 (Fig.5a on left). At high EGEF = 2.6, the primary energy saving increases with further increase in the NGEF, as shown in Fig.26a on right.

On the other hand, the CO_2 saving increases slightly for FC-GSHP system and increases significantly for PVT-GSHP system with further increase in natural gas emission factor, as shown in Fig.26b on right. In addition, there is a small effect of electricity grid emission factor on CO_2 saving for both systems (Fig.26b on left).

Moreover, Fig.26c displays the effect of natural and electricity gas prices on difference in the price of purchase electricity and own use/feed in the PVT-GSHP or FC-GSHP system (delta) in €/kWh. The results showed that the delta increases with further increase in natural gas price, as shown in Fig.26c on the right. The results showed also that there is no significant difference in delta between own-use and feed-in for both systems. On the other hand, both systems provide less delta for feed in compared to own use at high electricity price, as presented in Fig.26c on left.

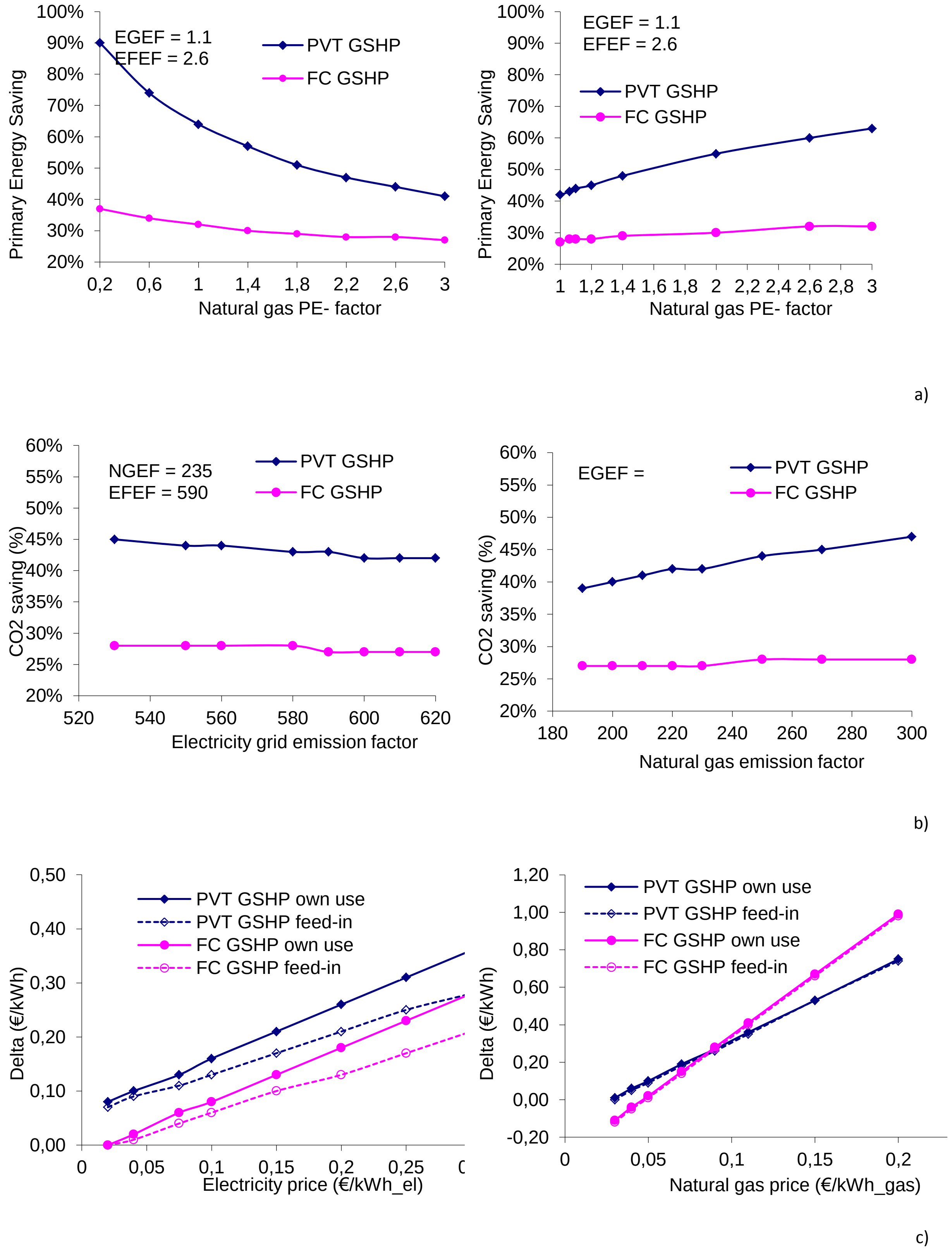
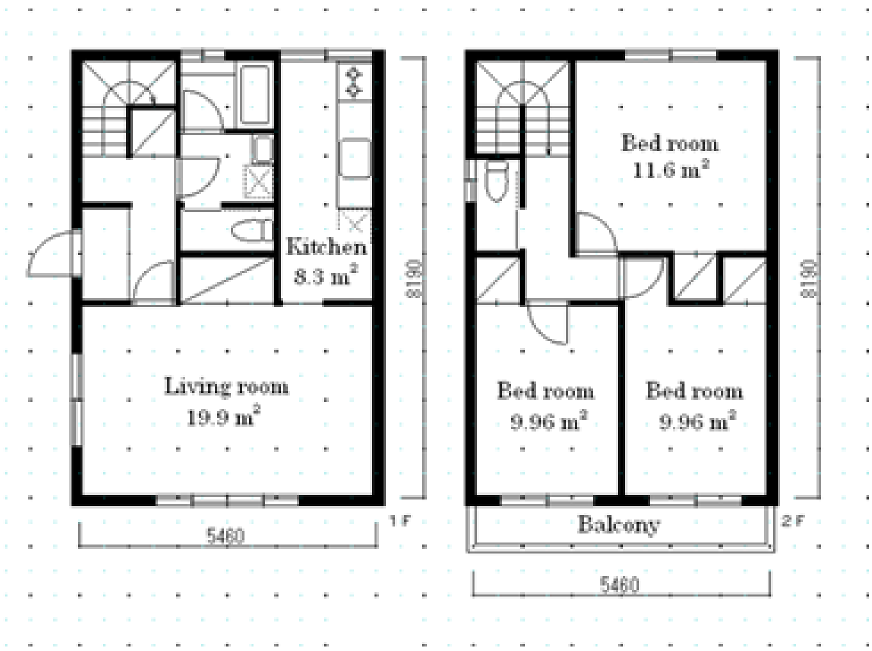


Fig.26 Primary energy saving, CO_2 emission saving and delta as a function of natural gas power energy factor (NGEF), natural gas and electricity emission factors and natural gas and electricity prices in Incheon.

2.7 Japan

Introduction

This study assesses the effect of Japanese policy support schemes on the introduction of fuel cells devices in residential buildings. Building type is assumed to be a detached house which has a living, 3 bedrooms, and a kitchen. It has 6 occupants (see Fig. 27).



Detached house 87.2m^2

Fig.27 **Example of the plan of the house used in the study [38]**

Energy loads have been derived from a model that is able to estimate a five-minute interval demand profiles, including hot water and electricity. Further information about the model can be found in [38]. The yearly thermal and electricity demand are of 9,176 and 6,247 kWh/year, respectively.

As in the previous cases, the assessment of energy, environmental and economic performances of the microgeneration system requires comparison with separate energy production, defined as the 'reference scenario', where the thermal demand is satisfied by a conventional boiler and the electricity is bought from the grid. Technologies considered are polymer electrolyte membrane fuel cells (PEFC) and solid oxide fuel cells (SOFC), which are commercialized in Japan and for which the main characterisation data is summed up, respectively, in Table 63 and 64 together with the characteristics of the reference scenario.

Table 63. Techno-economic parameters of PECFC installation and reference scenario.

MICROGENERATION INSTALLATION	
MICRO-CHP UNIT [1]	
Power output [kW_e]	0.75
Thermal output [kW_{th}]	1.08
Thermal input [kW_{th}]	2.1
Electrical efficiency	35%
Capital cost [€]	11,556
ADDITIONAL HEATING BOILER	
Capacity of the additional heating boiler [kW] [5]	42
Thermal efficiency of the boiler	95%
Capital cost [€/kW]	2,593
REFERENCE SCENARIO	
Capacity of the heating boiler [kW]	42
Thermal efficiency of the boiler	95%
Capital cost [€/kW]	2,593

Table 64. Techno-economic parameters of SOFC installation and reference scenario.

MICROGENERATION INSTALLATION	
MICRO-CHP UNIT [1]	
Manufacturer	
Power output [kW_e]	0.7
Thermal output [kW_{th}]	0.653
Thermal input [kW_{th}]	1.8
Electrical efficiency	39%
Capital cost [€]	15,259
ADDITIONAL HEATING BOILER	
Capacity of the additional heating boiler [kW][1]	42
Thermal efficiency of the boiler	95%
Capital cost [€/kW]	2,593
REFERENCE SCENARIO	
Capacity of the heating boiler [kW]	42
Thermal efficiency of the boiler	95%
Capital cost [€/kW]	2,593

With regards to supporting schemes currently available in Japan for fuel cells installations, the Government provides investment subsidies for installation. Furthermore the gas utility sets special tariffs on the gas feeding the fuel cell and back up boiler.

[5] Peak boiler for back-up is latent heat recovery type, differently from conventional boiler.

Baseline Performance Assessment (No Incentives)

The performance of the micro-CHP device, without considering any incentives, is now presented. The analysis has been conducted with the "Economic micro-CHP assessment tool" attached to the present report (see Appendix). Table 65 reports the technical and economic parameters used in the analysis.

Table 65. Techno-economic parameters used in the study.

Parameter	Value
PE factor for electricity [kWh_PE/kWh]	2.7
PE factor for NG [kWh_PE/kWh]	1
CO_2 factor for NG [g/kWh]	183
CO_2 factor for electricity [g/kWh]	559
Electricity purchasing price [c€/kWh][6]	21.2
NG price* [c€/kWh]	10.5
Subsidies on gas price [c€/kWh]	2.9

* referred to the Low Calorific Value

The reduced gas price has been considered also in the baseline performance assessment since it is set by the gas utility.

On the basis of results coming from the model developed, the PEMFC works 4,500 hours/year, and all the electricity produced is consumed onsite (covering the 54% of the demand), while the SOFC works the entire year, covering 98% of the electricity need. Results, reported in Table 66 and 67 show that the yearly total cost of both micro-CHP installations (given by the sum of capital, maintenance, gas and electricity cost) is higher than separate production, due to the high investment cost

Table 66. Results without incentive (PEMFC case).

	Microgeneration	Reference scenario	Δ
Total cost [€/y]	2,904	2,802	4%
Saldo [€/y] (cost-revenues)	2,904	2,802	4%
Operating costs [€/y]	1,684	2,529	-33%
PE [MWh_PE/y]	21.92	28.40	-23%
CO_2 [tCO_2/y]	4.2	5.6	-25%
CO_2 abatement costs [€/t]	15.63		
PE abatement costs [€/MWh]	72		
SPB [years]	Higher than lifetime[7]		

[6] Although both electricity and gas purchasing price depend on the monthly amount consumed, it has been assumed an average tariff.

Table 67. Results without incentive (SOFC case).

	Microgeneration	Reference scenario	Δ
Total cost [€/y]	3,188	2,802	14%
Saldo [€/y] (cost-revenues)	3,188	2,802	14%
Operating costs [€/y]	1,577	2,529	-38%
PE [MWh_PE/y]	19.8	28.40	-30%
CO_2 [tCO_2/y]	3.6	5.6	-36%
CO_2 abatement costs [€/t]	196		
PE abatement costs [€/MWh]	44.74		
SPB [years]	Higher than lifetime[7]		

. Nevertheless in all the cases analysed the introduction of microgeneration provides a reduction in the energy bill and reduction in primary energy consumption and CO_2 emissions. The SPB has been calculated as a ratio between the extra costs of the micro-CHP installation and savings in the energy bill.

Fig. 28 shows a comparison between CO_2 emission savings of the two microgeneration cases and reference system highlighting the contribution of electricity and gas consumption.

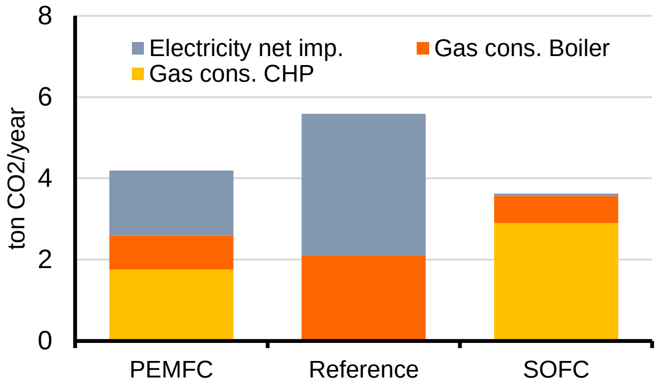


Fig. 28 **CO_2 emissions of the cases analysed**

Performance assessment with support mechanism

As discussed above, an investment subsidies is available for fuel cell installations, for the specific case a grant of about 3,000€ has been considered. Furthermore in Japan, the gas utilities provides a reduction in the gas price, in this case, since it does not come from the Government it has been considered also in the baseline case. Thank to investment subsidies the SPB is shorten to, respectively, 6.7 and 9.

[7] 10 years have been assumed for the lifetime of both systems

Table 68. Results with incentives (PEMFC case).

	Microgeneration	Reference scenario	Δ
Total cost [€/y]	2,552	2,802	-9%
Saldo [€/y] (Cost – revenues)	2,552	2,802	-9%
Operating cost [€/y]	1,684	2,529	-33%
PE [MWh_PE/y]	21.92	28.40	-23%
CO_2 [tCO_2/y]	4.2	5.6	-25%
SPB	6.7		

Table 69. Results with incentives (SOFC case).

	Microgeneration	Reference scenario	Δ
Total cost [€/y]	2,836	2,802	1.2%
Saldo [€/y] (Cost – revenues)	2,836	2,802	1.2%
Operating cost [€/y]	1,577	2,529	-38%
PE [MWh_PE/y]	19.8	28.40	-30%
CO_2 [tCO_2/y]	3.6	5.6	-36%
SPB	9		

Discussion

The impact of the Japanese scheme on micro-generation economic performance in a residential building has been assessed. PEMFC and SOFC have been considered, showing that without incentives, although more than 20% CO_2 savings can be achieved, the simple pay back is higher than the units' lifetimes.

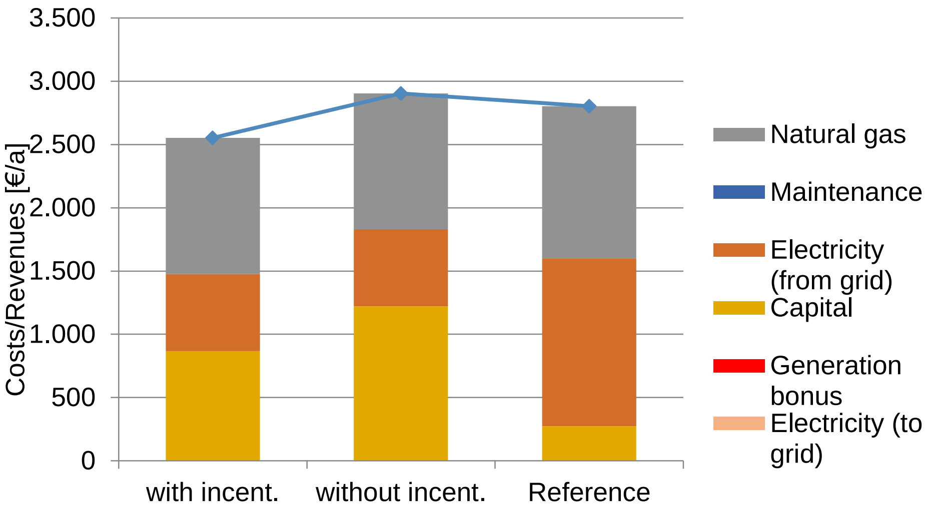


Fig.29 Comparison between the PEMFC case with and without incentives and the reference case, in Japan.

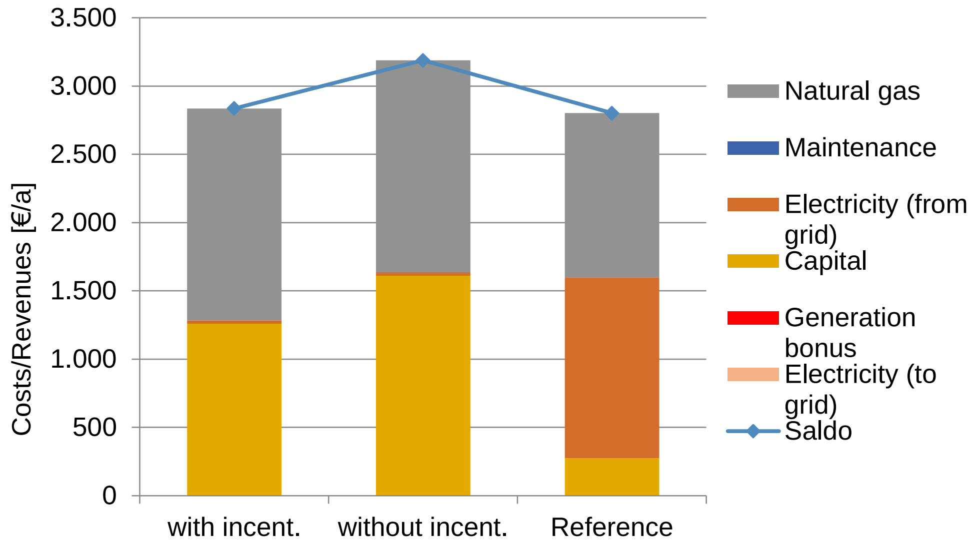


Fig.30 Comparison between the SOFC case with and without incentives and the reference case, in Japan.

3 Summary of country specific analysis

A range of case studies have been analysed in order to assess the effect of supporting policy instruments and regulatory-market frameworks on energy, environmental and economic performances of microgeneration systems. Table 70 gives a synoptic view of the cases analysed in the following section, specifying the sector investigated, the technology applied and the energy source for the systems analysed.

Table 70. Synoptic table of case studies analysed.

Country	Sector	Microgeneration technology	Support mechanism/ Regulatory-market framework	Sources typology
UK	Residential (single-dwelling)	ICE	FiT	NG
Germany	Residential (single detached house)	SE	FiT, NG tax rebate, grants	NG
Italy	Residential (multi-family house)	ICE	TWCs, NG tax rebate, grants	NG
	Tertiary (lecture room)	ICE + DCS	TWCs, NG tax rebate, grants	NG
	Tertiary sector (Sport facility; Schools; Office)	ICE + HCPV	TWCs, NG tax rebate, FiT	NG + solar energy
Canada	Residential (single-dwelling)	FC + Ion battery	TOU tariff	NG
	Residential (single-dwelling)	ICE; SE	Grant	NG
	Service/Residential (Office + house)	GSHP + FC	no subsidies	NG + ground source
	Service/Residential (Office + house)	GSHP + PVT	Grant	NG + solar energy
Flanders	Service/Residential (Office +hotel+ greenhouse+house)	ICE + SE	CHP certificate, Balancing market	NG
Korea	Residential (house)	ICE; SE	Grants	NG
	Service/Residential (Office + house)	GSHP + FC	Grants	NG + ground source
	Service/Residential (Office + house)	GSHP + PVT	Grants	NG + solar energy
Japan	Residential (house)	FC (PEMFC + SOFC)	Grants	NG

Most of the cases analysed deal with micro-CHP devices fuelled by natural gas. Different technologies have been considered, such as Internal Combustion Engine, ICE, Stirling engine, SE, Fuel Cell, FC, although most cases consider ICE, which is the most common small-scale cogeneration technology due to reasonable value of electrical efficiency and relatively low initial investment.

Some Annex participants (Italy, Canada, Korea) have analysed the effect of country-policy mechanisms on hybrid renewable energy systems, made up of a micro-CHP device (e.g. ICE, fuel cell) coupled with a renewable energy system (e.g. PV, PVT, GSHP). In such cases, the application can take advantage of incentives designed for renewable sources, which generally provide stronger incentives and are more widespread.

With regards to the sector investigated, as shown in Table 1, specific country analyses mainly focus on the residential sector, which is responsible for a large portion of GHG emissions in most jurisdictions. In EU, for instance, it affects 27% of total energy consumption, second only to the transport sector [1].

In order to provide an overview of the effect of different policy instruments on microgeneration applications, a comparative analysis, considering different selection criteria, is discussed below. Firstly, the effect of support mechanisms by sector has been considered. Secondly, the effect of the most widespread policy instruments (i.e. FiT and subsidy) has been modelled. Fig. 31 compares the influence of support mechanisms on energy, environmental and economic performance of microgeneration applications in residential sector.

The graph reports: i) the reduction in primary energy consumption, ΔPE(Eq.1) and ii) in carbon dioxide emissions, ΔCO_2, (Eq.2) calculated with respect to the reference system and iii) the Simple Pay Back, SPB, of the investment (Eq.3):

$$\Delta \mathrm{PE} = \frac{PE_{CS} - PE_{AS}}{PE_{CS}} \qquad (1)$$

$$\Delta CO_2 = \frac{CO_2^{CS} - CO_2^{AS}}{CO_2^{CS}} \qquad (2)$$

$$SPB = \frac{(Capital\_Cost_{AS} - subsidies) - Capital\_Cost_{CS}}{Operating\_Cost_{CS} - Operating\_Cost_{AS} + \mathrm{Re}venues_{AS}} \qquad (3)$$

Where, AS refers to the Alternative System(i.e. the microgeneration installation under analysis) and CS refers to the Conventional System, also known as “reference system”; the separate energy production where thermal demand is met by a heating boiler, cooling demand by a vapour compression chiller and the electrical demand via buying electricity from the grid.

It is worthy of note that, except for two cases (Italy and Flanders), the cost/benefit analyses discussed (see Fig.31) follows a deterministic approach, meaning that policy instruments affect solely the economic performances of microgeneration applications, and no changes in the operating strategies in response to the instrument are modelled.

Results show that, although the introduction of microgeneration systems in dwelling sector provides a reduction both in primary energy consumption and CO_2 emissions, ranging from 8% to 12%, the technologies that are commercially available are very capital intensive and therefore require support if they are to enter the market.

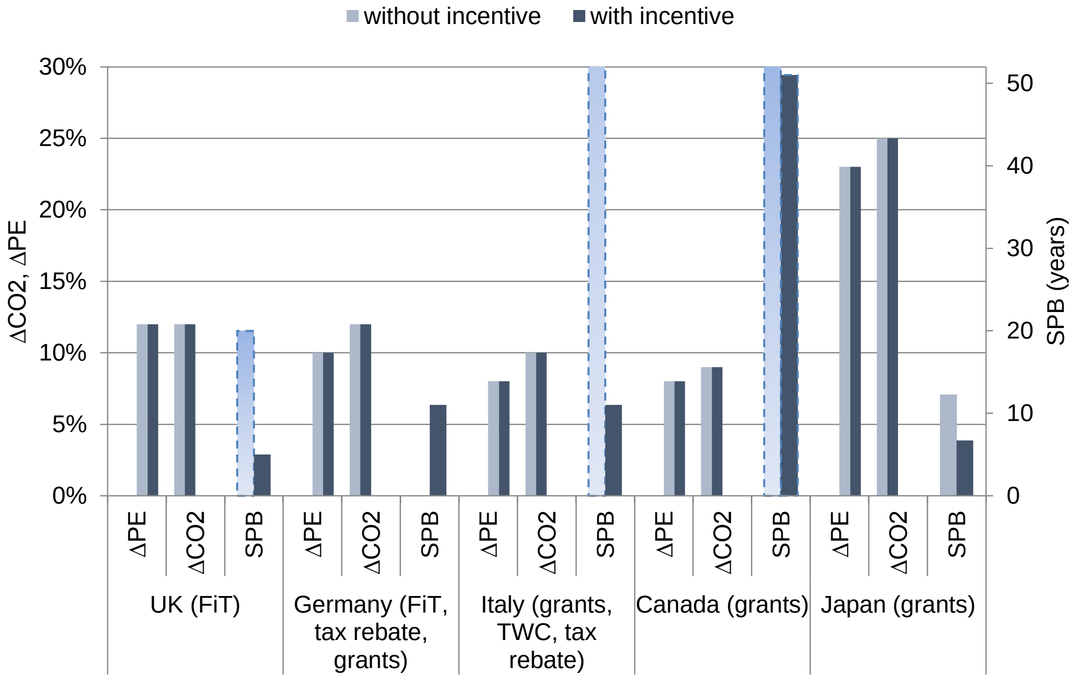


Fig.31 Influence of supporting schemes on residential applications in a selection of OECD countries. PE = Primary energy, CO_2 = Carbon dioxide, SPB = Simple payback.[8]

In order to quantify the amount of incentives to make them effective, Fig. 32 shows the relative contribution of support schemes (subsidies, tax rebates and FiT) to the annual total cost[9] without incentives for the UK (22%) and Germany case study (12%).

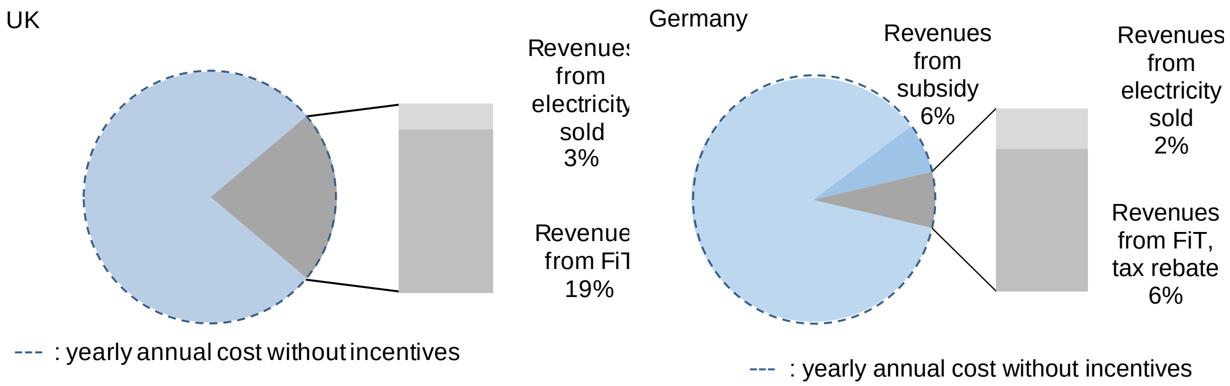


Fig.32 Relative value of incentives w.r.t. total annual cost, for UK and Germany.

[8] For Germany, as detailed in paragraph 3.2, the investment without incentives does not provide savings, thus the SPB can not be calculated. For Italy and Canada, the SPB without incentives, is greater than 50 years.

[9] The annuity of the investment cost, for the cases analysed, has been calculated using an interest rate of 3.5%.

For jurisdictions with lower value support, such as for Canada (see Fig. 33), the subsidy represents 3% of the total annual cost. With this approach SPB remains high.

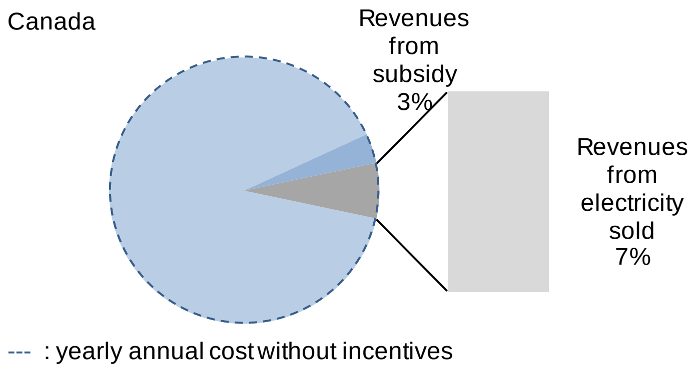


Fig.33 Relative value of incentives w.r.t. total annual cost, for Canada.

Fig. 34 shows the influence of support mechanisms for case studies belonging to the tertiary sector. As discussed in [39], indeed, several policy instruments are directed at small-size power devices (i.e. feed-in tariff in UK), that are more suitable for residential than tertiary sector applications. In order to overcome these barriers, it is possible that hybrid renewable energy systems, and new applications, such as load-sharing, could achieve up to 40% reduction in CO_2 emissions. Such approaches have been proposed in Canada and Korea.

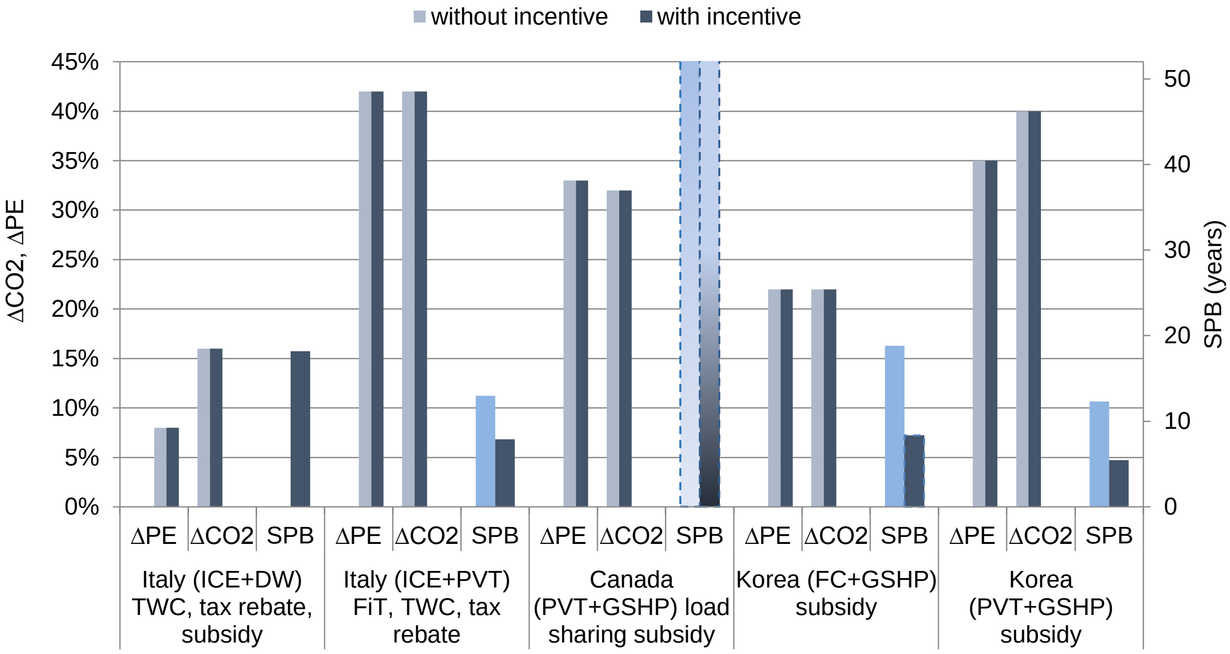


Fig.34 Influence on supporting schemes for service sector applications in a selection of OECD countries.

In the case of hybrid system applications (Korea and Italy) even without supporting schemes, as shown in Fig. 35, compelling results can be observed from both an environmental and economic point of view.

Since both hybrid renewable systems for the Korean and Canadian case studies are the same, the differences in energy and economic performances suggest the importance of energy loads and tariffs, in addition to incentives, to make the introduction of microgeneration effective.

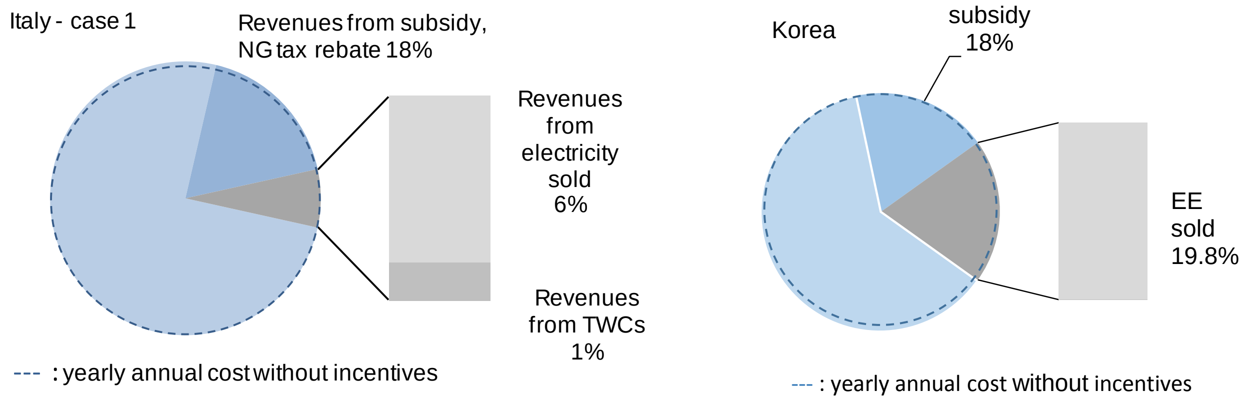


Fig.35 Relative value of incentives on total annual cost, for Italy (case 1) and Korea (GSHP+PV).

Italian policy instruments are crucial in helping to make the investment feasible (Fig. 36). For example, in the first case study, without revenues provided by incentives, the energy bill of the microgeneration system is even higher than separate energy production. Therefore incentives are indispensable if the investor is to have a chance of achieving payback. Fig. 36 focuses on the influence of the FiT scheme on SPB, showing also the incidence of revenues coming from FiT on operating costs. For all the cases analysed the introduction of the FiT scheme provides an important reduction in the SPB. If we compare the UK to the Italian case (Fig. 36), the lower reduction for the Italian case can be explained by the higher investment cost, since it is a hybrid renewable energy system.

Fig. 37 focuses on the influence of subsidies. If we consider the German case study, where the adoption of FiT scheme and subsidy has been assessed (Fig. 36 and 37), it can be seen that the effect of the FiT is higher. The result cannot be generalised since it depends on both the grant amount and the FiT value, which change from one country to another and over time.

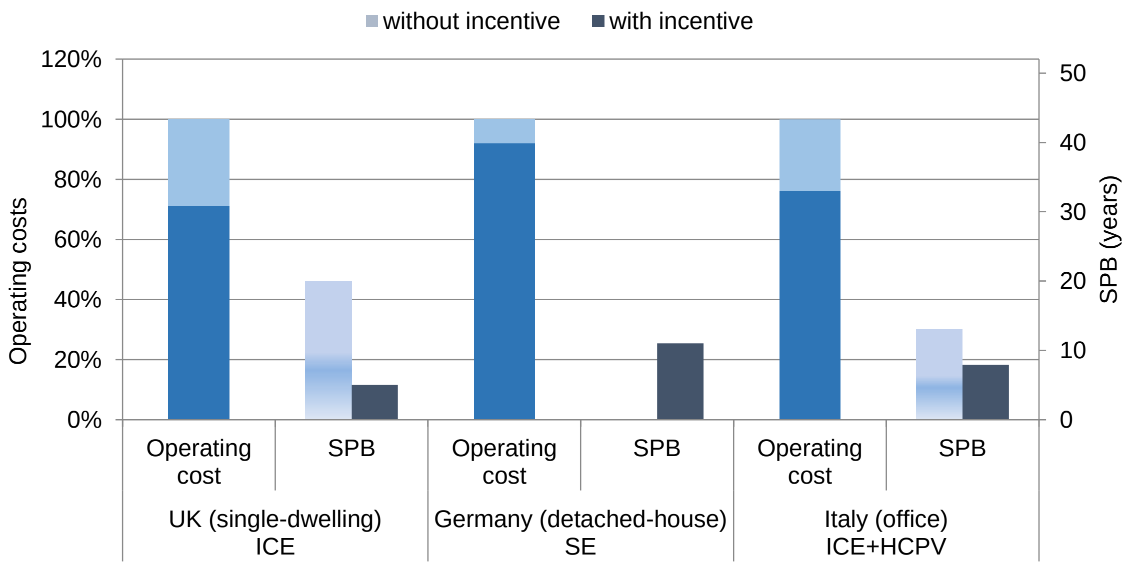


Fig.36 Effect of FiT scheme on a selection of case studies.

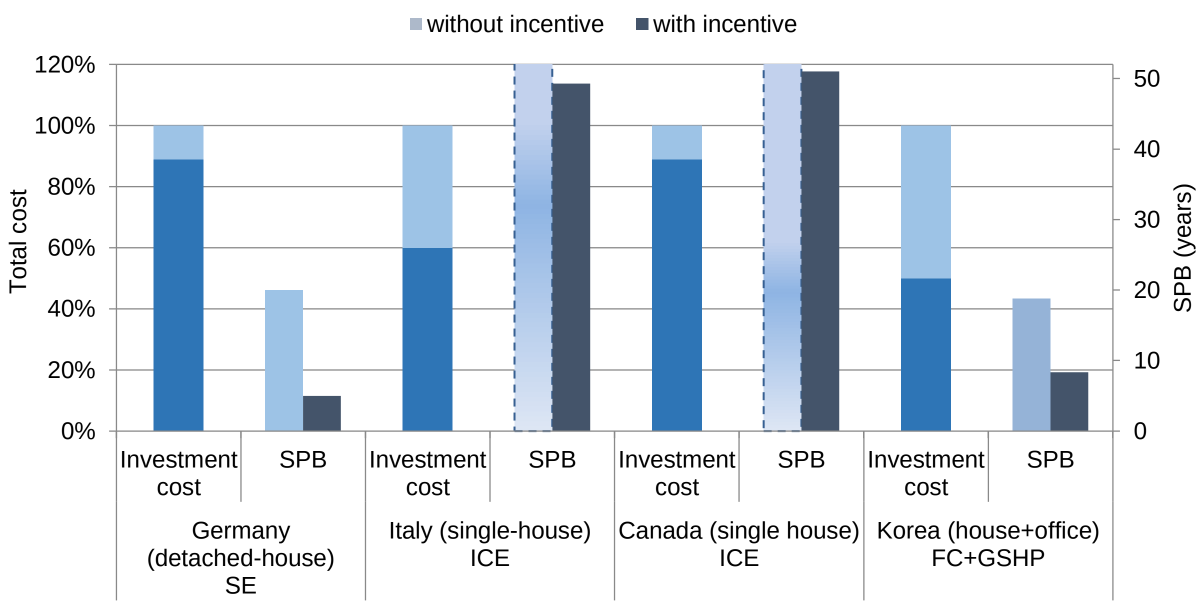


Fig.37 Effect of grants/subsidies scheme on a selection of case studies.

Finally it should be noted that in addition to policy instruments adopted by governments (e.g. grants, FiT, market mechanisms), also regulatory and market arrangements, such as TOU tariffs and the possibility to enter the balancing market- as shown in the case studies developed by Canada and Flanders - can be important instruments in order to help the introduction of microgeneration systems.

Nomenclature

The nomenclature used in the study is outlined in this chapter, including the list of indices.

AHU	Air Handling Unit
AS	Alternative System
CHP	Combined Heat and Power Production
CO_2	Carbon dioxide emissions
COP	Coefficient of Performance
CS	Conventional System
CS	Conventional System
D-A	Day-Ahead
DCS	Dessicant-based cooling system
DHW	Domestic Hot Water
DW	Dessicant Wheel
EE	Electric Energy
EFEF	Electricity Feed Energy Factor
EGEF	Electricity Grid Mix PE- factor
EU	Europe
FC	Fuel Cell
FiT	Feed in tariff mechanism
GCG	Govern Capital Grants
GHG	Greenhouse Gas
GSHP	Ground Source Heat Pump
HCPV	High Concentrator Photovoltaic System
HP	Heat Pump
HVAC	Heating Ventilation Air Conditioning
ICE	Internal Combustion Engine
LHV	Low Heating value
MC	maintenance cost
µ-CHP	micro-CHP
NG	Natural Gas
NGEF	natural gas PE factor
OC	Operating Cost
OECD	Organisation for economic Co-operation and Development
P	Power
PE	Primary energy
PEMFC	Proton-Exchange Membrane Fuel-Cell
PES	Primary Energy Saving
PV	Photovoltaic
PVT	Photovoltaic Thermal
RT	Real Time
SE	Stirling engine
SPB	Simple Pay Back
SS	Storage Settlement
TCS	Thermal Cooling System
toe	ton of oil equivalent
TOU	Time of use tariff

TR	Tax rebate
TWC	Tradable White Certificate
VAT	Value Added Tax
VCC	Vapor compression chiller
VPP	Virtual Power Plant
w	weight

Subscripts

cool	cooling
e	electric
p	peak
th	thermal

Appendix: Micro-CHP Economic Assessment Tool

The tool developed by the Technical University of Munich in collaboration with Università del Sannio and Imperial College London, is aimed at comparing the economic performances of a microgeneration system with and without incentives.

In order to correctly assess the microgeneration system, as required by the cogeneration concept, its performances are compared to ones of the reference system (separate energy production), in which the thermal demand is satisfied by a heating boiler, the cooling demand by a vapor compression chiller and the electricity demand buying energy from the grid.

The main input parameters, which are detailed in Table 71, are:

- characteristics of both the microgeneration and reference system
- electricity, thermal and cooling demand to be satisfied
- PE factor and CO_2 emission factors
- Energy tariffs
- Capital costs of both the microgeneration and reference system
- Incentives

Table 71. Input parameters.

Microgeneration system with incentives	Microgeneration system without incentives	Reference system
Step 1: Energy demand: (thermal, electrical and cooling demand)		
Step 2: Definition of the main characteristics of the micro-CHP system and reference system		
→ Thermal power of the micro-CHP system and boiler		→ Thermal power of the boiler
→ Electrical power		→ Cooling power of the VCC
→ Cooling power of the Thermal cooling System, TCS		→ Total efficiency of the boiler and VCC
→ Total efficiency of the micro-CHP, boiler and TCS		
→ Nominal gas consumption		→ Nominal gas consumption
→ Heat consumption of the TCS		→ Electricity consumption of VCC
Step 3: Definition of the energy system operation		
→ Share of own use electricity		
→ Utilization time (number of operating hours at nominal power)		
Step 4: Introduction of the parameters for the economic analysis		
→ Invest cost	→ Invest cost	→ Invest cost
→ Invest subsidies		→ Invest subsidies*
→ Lifetime	→ Lifetime	→ Lifetime
→ Interest rate	→ Interest rate	→ Interest rate
→ Maintenance cost	→ Maintenance cost	→ Maintenance cost
→ Gas price	→ Gas price	→ Gas price
→ Subsidies on gas price		
→ Electricity price (from grid)	→ Electricity price (from grid)	→ Electricity price (from grid)
→ Feed in Tariff (to grid)	→ Feed in Tariff	
→ CHP generation bonus		

*It is assumed that a subsidy can be recognized also to conventional energy systems

Table 72 shows the output parameters calculated by the tool, and the formulas of the main outputs.

Table 72. Outputs calculated by the tool.

Microgeneration system with incentives	Microgeneration system without incentives	Reference system
Energy performances of the systems		
→ Gas consumption		→ Utilization time
→ Heat production		→ Gas consumption
→ Heat to the TCS		→ Heat production
→ Heat for the thermal demand		
→ Electricity generation		
→ Electricity from grid		→ Electricity from the grid
→ Electricity to grid		
Economic balance		
Costs:	Costs:	Costs:
→ Capital cost	→ Capital cost	→ Capital cost
→ Maintenance costs	→ Maintenance costs	→ Maintenance costs
→ Gas costs	→ Gas costs	→ Gas costs
→ Electricity costs (from grid)	→ Electricity costs (from grid)	→ Electricity costs (from grid)
Sum costs	Sum costs	Sum costs
Revenues :	Revenues:	
→ Electricity feed (to grid)	Electricity feed (to grid)	
→ CHP generation bonus		
Saldo= sum costs – revenues	*Saldo= sum costs – revenues*	*Saldo =sum costs*
CO_2 balance		
→ Natural gas emissions		→ Natural gas emissions
→ Electricity import (from grid)		→ Electricity import (from grid)
→ Electricity export (to grid)		
Sum emissions: Total CO2 micro-CHP		Sum emissions: Total CO_2 reference system
CO_2 savings=CO_2 micro-CHP – CO_2 reference system		
PE balance		
→ Natural gas emissions		→ Natural gas emissions
→ Electricity import (from grid)		→ Electricity import (from grid)
→ Electricity export (to grid)		
Total PE *micro-CHP*		Total PE *reference system*
PE savings=PE micro-CHP – PE reference system		
CO_2 abatement cost		
Additional costs = Saldo without incentives – Saldo reference systems		
CO_2 abatement = Additional costs / Total CO_2 micro-CHP		
PE abatement cost		
Additional costs=Saldo without incentives – Saldo reference systems		
PE abatement= Additional costs / Total PE *micro-CHP*		

As shown in Table 73, the tool is able to assess: i) the microgeneration energy performances with respect to the reference system and ii) the economic performances of the microgeneration system with incentive and without incentives. Finally Fig.38 gives an overview of how the "Economic assessment tool" works.

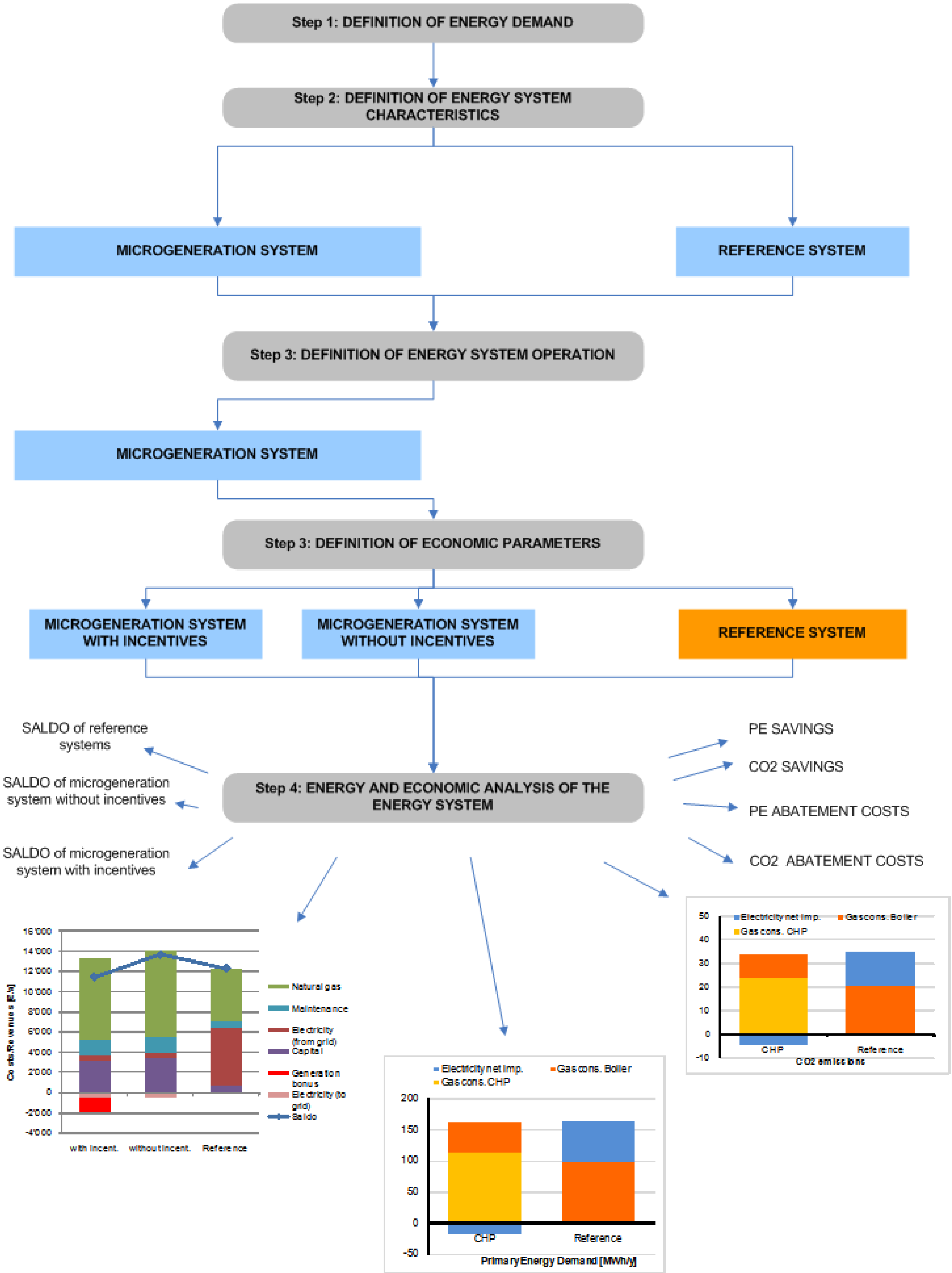


Fig.38 Conceptual scheme of the operation of the “Economic assessment tool”.

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Background Information

International Energy Agency

The International Energy Agency (IEA) was established in 1974 within the framework of the Organisation for Economic Co-operation and Development (OECD) in order to implement an international energy programme. A basic aim of the IEA is to foster international co-operation among the 28 IEA-participating countries, as well as to increase energy security through energy research, development, and demonstration in the fields of technologies for energy efficiency and renewable energy sources.

The IEA Energy in Buildings and Communities Programme

The IEA co-ordinates research and development in a number of areas related to energy. The mission of the Energy in Buildings and Communities (EBC) Programme is to develop and facilitate the integration of technologies and processes for energy efficiency and conservation into healthy, low emission, and sustainable buildings and communities, achieving this through innovation and research. (Until March 2013, the IEA-EBC Programme was known as the Energy in Buildings and Community Systems Programme, ECBCS.)

The research and development strategies of the IEA-EBC Programme are derived from research drivers, national programmes within IEA countries, and the IEA Future Buildings Forum Think Tank Workshops. The research and development (R&D) strategies of IEA-EBC aim to exploit technological opportunities to save energy in the buildings sector, and to remove technical obstacles to market penetration of new energy-efficient technologies. The R&D strategies apply to residential, commercial, office buildings, and community systems, and will impact the building industry in five focus areas for R&D activities:

- Integrated planning and building design
- Building energy systems
- Building envelope
- Community scale methods
- Real building energy use

The Executive Committee

Overall control of the IEA-EBC Programme is maintained by an Executive Committee, which not only monitors existing projects but also identifies new strategic areas in which collaborative efforts may be beneficial. As the programme is based on a contract with the IEA, the projects are legally established as Annexes to the IEA-EBC Implementing Agreement. At the present time, the following projects have been initiated by the IEA-EBC Executive Committee, with completed projects identified by (*):

Annex 1: Load Energy Determination of Buildings (*)
Annex 2: Ekistics and Advanced Community Energy Systems (*)

Annex 3: Energy Conservation in Residential Buildings (*)
Annex 4: Glasgow Commercial Building Monitoring (*)
Annex 5: Air Infiltration and Ventilation Centre
Annex 6: Energy Systems and Design of Communities (*)
Annex 7: Local Government Energy Planning (*)
Annex 8: Inhabitants Behaviour with Regard to Ventilation (*)
Annex 9: Minimum Ventilation Rates (*)
Annex 10: Building HVAC System Simulation (*)
Annex 11: Energy Auditing (*)
Annex 12: Windows and Fenestration (*)
Annex 13: Energy Management in Hospitals (*)
Annex 14: Condensation and Energy (*)
Annex 15: Energy Efficiency in Schools (*)
Annex 16: BEMS 1- User Interfaces and System Integration (*)
Annex 17: BEMS 2- Evaluation and Emulation Techniques (*)
Annex 18: Demand Controlled Ventilation Systems (*)
Annex 19: Low Slope Roof Systems (*)
Annex 20: Air Flow Patterns within Buildings (*)
Annex 21: Thermal Modelling (*)
Annex 22: Energy Efficient Communities (*)
Annex 23: Multi Zone Air Flow Modelling (COMIS) (*)
Annex 24: Heat, Air and Moisture Transfer in Envelopes (*)
Annex 25: Real time HVAC Simulation (*)
Annex 26: Energy Efficient Ventilation of Large Enclosures (*)
Annex 27: Evaluation and Demonstration of Domestic Ventilation Systems (*)
Annex 28: Low Energy Cooling Systems (*)
Annex 29: Daylight in Buildings (*)
Annex 30: Bringing Simulation to Application (*)
Annex 31: Energy-Related Environmental Impact of Buildings (*)
Annex 32: Integral Building Envelope Performance Assessment (*)
Annex 33: Advanced Local Energy Planning (*)
Annex 34: Computer-Aided Evaluation of HVAC System Performance (*)
Annex 35: Design of Energy Efficient Hybrid Ventilation (HYBVENT) (*)
Annex 36: Retrofitting of Educational Buildings (*)
Annex 37: Low Exergy Systems for Heating and Cooling of Buildings (LowEx) (*)
Annex 38: Solar Sustainable Housing (*)
Annex 39: High Performance Insulation Systems (*)
Annex 40: Building Commissioning to Improve Energy Performance (*)
Annex 41: Whole Building Heat, Air and Moisture Response (MOIST-ENG) (*)
Annex 42: The Simulation of Building-Integrated Fuel Cell and Other Cogeneration Systems (FC+COGEN-SIM) (*)
Annex 43: Testing and Validation of Building Energy Simulation Tools (*)
Annex 44: Integrating Environmentally Responsive Elements in Buildings (*)

Annex 45: Energy Efficient Electric Lighting for Buildings (*)
Annex 46: Holistic Assessment Tool-kit on Energy Efficient Retrofit Measures for Government Buildings (EnERGo) (*)
Annex 47: Cost-Effective Commissioning for Existing and Low Energy Buildings (*)
Annex 48: Heat Pumping and Reversible Air Conditioning (*)
Annex 49: Low Exergy Systems for High Performance Buildings and Communities (*)
Annex 50: Prefabricated Systems for Low Energy Renovation of Residential Buildings (*)
Annex 51: Energy Efficient Communities (*)
Annex 52: Towards Net Zero Energy Solar Buildings (*)
Annex 53: Total Energy Use in Buildings: Analysis & Evaluation Methods (*)
Annex 54: Integration of Micro-Generation & Related Energy Technologies in Buildings
Annex 55: Reliability of Energy Efficient Building Retrofitting - Probability Assessment of Performance & Cost (RAP-RETRO)
Annex 56: Cost Effective Energy & CO2 Emissions Optimization in Building Renovation
Annex 57: Evaluation of Embodied Energy & CO2 Emissions for Building Construction
Annex 58: Reliable Building Energy Performance Characterisation Based on Full Scale Dynamic Measurements
Annex 59: High Temperature Cooling & Low Temperature Heating in Buildings
Annex 60: New Generation Computational Tools for Building & Community Energy Systems Based on the Modelica & Functional Mockup Unit Standards
Annex 61: Development & Demonstration of Financial & Technical Concepts for Deep Energy Retrofits of Government / Public Buildings & Building Clusters
Annex 62: Ventilative Cooling
Annex 63: Implementation of Energy Strategies in Communities
Annex 64: LowEx Communities - Optimised Performance of Energy Supply Systems with Exergy Principles
Annex 65: Long-Term Performance of Super-Insulation in Building Components and Systems
Annex 66: Definition and Simulation of Occupant Behaviour in Buildings

Working Group - Energy Efficiency in Educational Buildings (*)
Working Group - Indicators of Energy Efficiency in Cold Climate Buildings (*)
Working Group - Annex 36 Extension: The Energy Concept Adviser (*)

(*) – Completed

Annex 54

The **Annex 54 "Integration of Micro-Generation and Related Energy Technologies in Buildings"** undertook an in depth analysis of micro-generation and associated other energy technologies.

Scope of activities

- multi-source micro-cogeneration systems, polygeneration systems (i.e. integrated heating / cooling / power generation systems) and renewable hybrid systems;
- the integration of micro-generation, energy storage and demand side management technologies at a local level (integrated systems);
- customised and optimum control strategies for integrated systems;
- the analysis of integrated and hybrid systems performance when serving single and multiple residences along with small commercial premises; and
- the analysis of the wider impact of micro-generation on the power distribution system. To broaden the impact of the Annex's output there will be significant effort to disseminate its deliverables to non-technical stakeholders working in related areas such as housing, product commercialisation and regulatory development.

Outcomes

- An update on occupant related DHW and electric load profiles.
- Component models and their implementation in building simulation tools.
- Review of best practice in the operation and control of integrated micro-generation systems.
- Predictive control algorithms to maximize the performance and value of micro-generation.
- Experimental data sets for the calibration and validation of device models.
- Performance assessment methodologies.
- Country-specific studies on the performance of a range of micro-generation systems.
- Studies of the viability of micro-generation systems in different operational contexts and of the impacts of micro-generation on the wider community and the potential benefits, in particular for the electricity network.
- An investigation of interactions between technical performance and comercialization/ regulatory approaches for micro-generation.
- Compilation of case studies of the introduction of microgeneration technologies.

Annex 54 was built upon the results of Annex 42 "The Simulation of Building-Integrated Fuel Cell and Other Cogeneration Systems".

To accomplish its objectives Annex 54 conducted research and development in the framework of the following three Subtasks:

Subtask A - Technical Development

The subtask contains a broad range of activities related to models and load profiles development, data collection and micro-generation systems predictive controls development and optimization.

Subtask B - Performance Assessment

The subtask uses simulations to develop an extensive library of performance studies and synthesis techniques to identify generic performance trends and “rules of thumb” regarding the appropriate deployment of micro-generation technologies.

Subtask C - Technically Robust Mechanisms for Diffusion

The subtask contains work related to the interaction between technical performance, economic instruments and commercialization strategies and provision of this information to the relevant decision makers. Given the importance of micro-generation in meeting many countries’ climate change targets the subtask assesses the ability of micro-generation to enter the market and deliver on national and international energy policy objectives.

Research Partners of Annex 54

Belgium	Catholic University of Leuven
Canada	Natural Resources Canada
	National Research Council
	Carleton University
Denmark	Dantherm Power A/S
Germany	Research Center for Energy Economics (FfE)
	Technische Universität München (TUM)
	University of Applied Science of Cologne
Italy	Università degli Studi del Sannio
	Seconda Università di Napoli (SUN)
	National Agency for New Technologies, Energy and Sustainable Economic Development (ENEA)
	Università Politecnica delle Marche
Japan	Tokyo University of Agriculture and Technology
	Osaka University
	Nagoya University
	Tokyo Gas
	Osaka Gas
	Toho Gas
	Saibu Gas
	Mitsubishi Heavy Industry Ltd
	Yanmar Energy Systems Ltd
Korea	Korean Institute for Energy Research (KIER)
Netherlands	Technische Universiteit Eindhoven (TU/E)
United Kingdom	University of Strathclyde, Scotland
	Imperial College London, England
	University of Bath, England
United States	National Institute for Standards and Technology (NIST)