Energy Policy 34 (2006) 804–832

ENERGY POLICY

www.elsevier.com/locate/enpol

Small distributed generation versus centralised supply: a social cost–benefit analysis in the residential and service sectors

Francesco Gullí*

Economics, Bocconi University, Iefe-Universita Bocconi Viale Filipetti 9, 20122 Milano, Italy

Available online 23 September 2004

Abstract

This paper aims at measuring the social benefits of small CHP distributed generation (DG) in the residential and service sectors. We do this by comparing the social costs of decentralised and centralised supplies, simulating "ideal" situations in which any source of allocative inefficiencies is eliminated. This comparison focuses on assessing internal and external costs. The internal costs are calculated by simulating the optimal prices of the electricity and gas inputs. The external costs are estimated by using and elaborating the results of the dissemination process of the ExternE project, one of the most recent and accurate methodologies in this field. The analysis takes into account the main sources of uncertainty about the parameter values, including uncertainty about external cost estimations. Despite these sources of uncertainty, the paper concludes that centralised supply is still preferable to small DG. In fact, the overall range of DG social competitiveness is restricted, even considering further remarkable improvements in DG electrical efficiency and investment costs. The results are particularly unfavourable for the residential sector, whereas, in the service sector, the performance of DG technologies is slightly better.
© 2004 Elsevier Ltd. All rights reserved.

Keywords: Distributed generation; Social cost–benefits analysis; Technological change

1. Introduction

Restructuring and privatisation of electricity and gas industries is occurring world wide and clearly confirms the general tendency to abandon the traditional organisation based on the operation of large firms.

Nevertheless, the impact of the market reforms in terms of social welfare is not clear yet. Although several analyses have been proposed in this field, the results do not converge. In the meanwhile, some recent dramatic events (i.e. the California energy crisis, the collapse of Enron and the black-out in the USA and in several European countries) and some profound changes introduced in those countries firstly promoting liberalisation processes have increased the number of those who question the real benefits of such an organisational change.

However, while this issue is still being debated, technological change and innovation offer us the prospect of revolutionary new scenarios. In particular, the performance of the small power technologies (i.e. reciprocating engine and gas turbine) has improved remarkably over the last decade. This has aroused the interest of operators, regulators and legislators in distributed generation (DG), namely, the integrated or stand-alone use of small, modular power generation close to the point of consumption as an alternative to large power generation and electricity transport over long distances.

DG can provide several benefits which can be divided into two categories.[1] The first includes the so-called

[1] As regards DG benefits and the relationship between technological change and market organisation, see Pfeifenberger et al. (1997) and Arthur D. Little (1998).

*Tel.: +390258363824; fax: +3958363890.
E-mail address: francesco.gulli@unibocconi.it (F. Gullí).

0301-4215/$ - see front matter © 2004 Elsevier Ltd. All rights reserved.
doi:10.1016/j.enpol.2004.08.008

structural benefits whose existence does not depend on how markets are organised: avoided electricity transmission costs; reduced energy costs through combined heat and power generation;[2] increased power supply reliability, etc. The second category includes the so-called market-related benefits whose extent depends on how markets are organised (e.g. decreased exposure to electricity price volatility).

However, the realisation that DG could provide these benefits does not mean that decentralisation is undoubtedly preferable to large power generation, for the following reasons.

First, fuel cost saving due to combined heat and power generation and avoided transmission costs might be offset by higher investment costs.

Second, despite the higher overall energy efficiency, and consequently reduced greenhouse gases emissions (GHG), DG technologies might involve higher non-GHG emissions (SO_x, NO_x, particulate, etc.).

Third, there are considerable differences between centralised and decentralised technologies in terms of the impact of non-GHG emissions (SO_x, NO_x, particulate, etc.). These differences might be due to micro-localisation effects. Unlike large power plants (high stack and extra-urban location), distributed technologies have low stacks and might be located in densely populated urban areas. Because of low stacks (emissions at extremely low altitudes), pollutant atmospheric dilution could be lower so that the increases in pollutant concentration close to the plant could be higher than those of a large power plant. Due to location, these high increases in pollutant concentration occur in highly populated areas and seriously damage human health. These combined effects might cause an environmental impact (per unit of pollutant emitted) higher than that of a large power plant.

Taking into account these effects, we aim at evaluating what is the real social benefit of energy supply decentralisation. Nevertheless, we do not analyse all the possible typologies of DG. We focus on small DG that is supply decentralisation by means of plants with power size ranging from 5 kW to 5 MW (following the classification[3] of Ackermann et al., 2001).

Furthermore, we are interested in applications representative of a wide deployment of small DG plants. This implies that we should analyse the residential and service sectors. Therefore, we simulate the application of small CHP DG to a residential building and a hospital (as representative of the service sector).[4] Moreover, this choice allows us to verify whether we are moving towards a radically different energy market paradigm.

The results showed in this paper are based upon a detailed technical analysis of energy flows of the fuel cycles (centralised and decentralised systems). Environmental externalities are assessed by using the results of the dissemination process of the ExternE methodology,[5] one of the most ambitious and internationally recognised attempts at coming up with "true" external cost estimates for the different power technologies (Krewitt, 2002). We are aware such a methodology could be largely imperfect. Nevertheless, we think that it could provide useful and reliable indications when used to compare technological alternatives and when the uncertainty about value estimations can be internalised into the estimating model.

Finally, the analysis focuses on a simulation of a particular territorial context, the case of Italy. However, as we will explain in Section 2, this simulation is particularly significant, so that the results obtained can be generalised.

The paper attempts to analyse all the issues affecting the comparison between centralised supply and DG: economics of electricity supply (including network effects); economics of combined heat and power generation; economics of supply reliability; valuation of environmental externalities, etc.

In particular, the article is organised as follows. Section 2 illustrates the general approach and main assumptions of the analysis. Section 3 focuses on economics of CHP generation, comparing centralised and decentralised supply in terms of energy efficiency, the first rough performance indicator. Section 4 evaluates internal costs and benefits, which are calculated by simulating optimal prices of the electricity and natural gas inputs (by using a specific formulation of the peak load pricing problem). Section 5 focuses on external costs and benefits, which are calculated by using and elaborating the results of the dissemination process of the ExternE project. The results are presented in terms of cumulative probability distribution in order to evaluate the impact of statistical and political uncertainty, mainly regarding the estimation of the marginal cost of atmospheric pollutant emissions.

[2] Customer proximity greatly increases the potential for cogeneration. The high costs of transporting heat even over short distances make large-scale cogeneration unattractive.

[3] Ackermann et al. consider DG an electric power source connected directly to the distribution network or on the customer site of the meter. They suggest the following categories: micro DG (1 Watt < kW); small DG (5 kW < 5 MW); medium DG (5 MW < 50 MW); large DG (50 MW < 300 MW).

[4] Service sector includes several applications (hospital, airports, public buildings, universities, etc.). In order to strengthen our analysis we refer to an application (the hospital) which is particularly suitable for small combined heat and power generation, given the level of heat and cold consumption.

[5] The ExternE project is a major research program launched by the European Commission at the beginning of the 1990s to provide a scientific basis for the quantification of energy-related externalities and to give guidance supporting the design of internalisation measures (Krewitt, 2002).

Section 6 analyses the total costs and benefits (internal plus external). Section 7 attempts to verify the robustness of the final results by carrying out a sensitivity analysis and assessing the overall range of DG social competitiveness. In this section, among the other things, we account for the network effects of DG, the problem of electricity and gas transport congestions and the advantages of DG in terms of power supply reliability. The final section summarises the main results of the paper.

2. General approach and main assumptions

Measuring social benefits implies the following choices and methodological assumptions.

First, we should compare centralised and decentralised supply in terms of social costs. Thus we conduct a cost comparison on a static model that is an approximation of welfare comparison.[6]

Second, since we are interested in a wide deployment of DG, we deal with fossil fuel plants (especially natural gas fired technologies).[7]

Third, we should not be concerned with the real world where several possible sources of distortions (market power, energy taxation and inefficient regulated prices) could give a false representation of DG social value. Therefore, ''ideal'' situations should be investigated and, consequently, any sources of allocative inefficiencies eliminated. This requires, on the one hand, simulating optimal prices of the electricity and gas inputs and, on the other, removing the ''incompleteness of the markets'' due to environmental external costs.

Fourth, we believe that, since we are dealing with ''ideal'' situations, only the structural DG benefits (i.e. energy saving due to combined heat and power generation; avoided transmission costs; increasing power supply reliability) should be taken into account, excluding benefits and advantages due to specific market organisations[8] which might involve the risk of accounting for effects due to market distortions (e.g. reduced exposure to high price volatility due to market power in power markets).

Finally, since DG costs depend on several exogenous parameters (i.e. structure of the territory, natural gas price, geographic position, etc.), how can we obtain a reliable measure of its social benefits? In this respect it is obvious that it is impossible to provide a single value of DG social benefit but that a range of variability must be proposed. This means that our estimating model should be as flexible as possible in order to take into account the variability of the exogenous parameters. Since this variability can be very high it would be very difficult (and superfluous) to examine all the possible combinations of values. Our analysis will therefore focus on the best and worst cases.

The exogenous variables affecting DG costs and benefits can be divided into two categories. The first includes variables which change significantly over time (i.e. natural gas price) and over ''space'' (i.e. electricity and gas distribution costs). In order to consider the impact of their variability on DG benefits we will carry out a sensitivity analysis (Section 7).

The second category includes those factors that cannot be expressed as parametric variables. The most important is the geographic location of the plants which considerably affects the environmental impact of the fuel cycles. This effect could be considered by finding a geographic context (i.e. a country) where there are at least two locations which represent extreme environmental situations. In this respect, Italy, the country chosen for this analysis, provides a very useful case study for the following reasons.

First, its geographic configuration, a long latitudinal extension from the centre of Europe to the centre of the Mediterranean Sea, makes it easy to identify two locations with the required characteristics. In fact, if we applied our model in the north (e.g. in Milan) and in the south (e.g. in Palermo) we would find two opposite situations in terms of regional environmental damage. The case of Milan represents a very high environmental impact since it is located near a region (the centre of Europe) which is densely populated and relatively far from the sea. On the contrary, the case of Palermo represents a very low regional environmental impact since the city is located in a region far from the centre of Europe and surrounded by the sea (since plant pollution is mainly discharged directly into the sea, the potential environmental impact is very low).[9] We image DG plants are located in north (e.g. Milan) and south (e.g. Palermo) of Italy while we suppose the large power plant is located in the centre of Italy (in other words, in the case of power centralised supply, we will use the Italian average environmental impact).

3. Technologies, applications and energy saving

Before assessing DG external benefits, it is necessary to compare centralised and decentralised systems in

[6]With regard to social cost–benefit analysis we have referred to the methodology developed by Jones et al. (1990) and Newbery (2001). Although this methodology aims to evaluate privatisation processes, it is also useful to investigate the social impact of industry restructuring or, as in our case, technological and organisational alternatives.

[7]Since small DG plants are generally located in urban areas, natural gas is the most appreciated fuel because of its low environmental impact compared to other fossil fuels.

[8]For a detailed explanation of this choice, see Gullí (2003).

[9]Since small DG plants are generally located in urban areas, natural gas is the most appreciated fuel because of its low environmental impact compared to other fossil fuels.

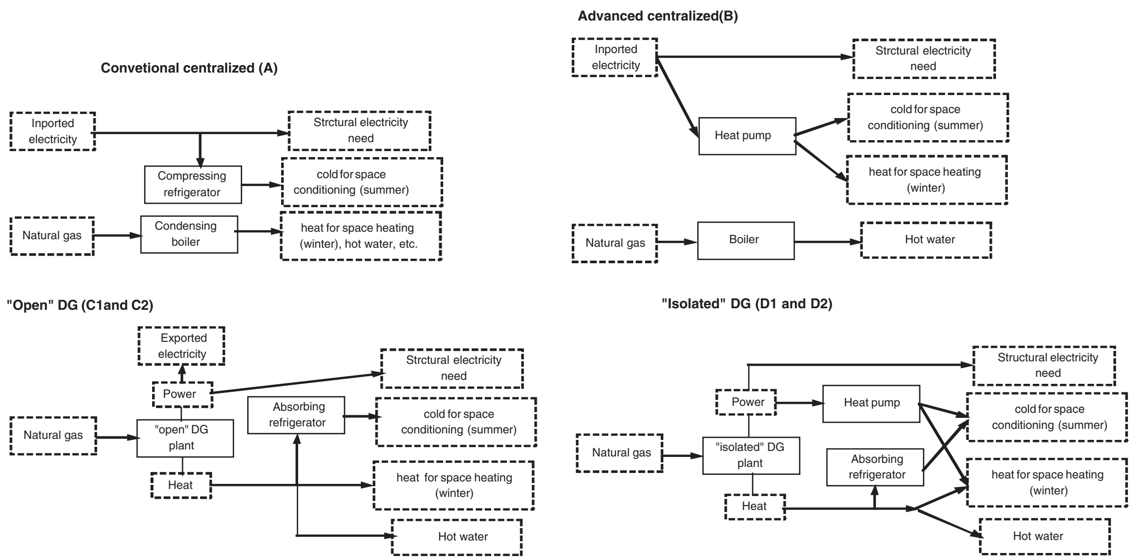

Fig. 1. Centralised and decentralised systems: technical schemes.

terms of energy efficiency, the first rough indicator of performance.

We consider six technological solutions: two based on centralised supply (A and B) and four on decentralised supply (C1, C2, D1 and D2). The applications are a residential building and a hospital. Energy consumption include all customer needs: heat for domestic heating and sanitary uses, cold for air conditioning, and structural electricity needs (lighting, power for domestic appliances, etc.). Heat for space heating and cold for air conditioning depend on plant location (Milan or Palermo) while the structural electricity needs are assumed to be identical. The simplified technical schemes of the different solutions are reported in Fig. 1. Technical parameters of the technologies and applications are reported in Appendix A. (Tables A.1–A.4).

3.1. Centralised systems

Solution A includes a conventional condensing boiler (with 90% thermal efficiency) providing heat for space heating and sanitary uses (hot water). A conventional compressing refrigerator supplies cold for air conditioning. Imported electricity is assumed to be generated by a large combined cycle-gas turbine plant (CCGT), with 54% electrical efficiency, which is the power generating marginal technology. Energy losses due to electricity transport and distribution are assumed equal to 6%. Solution B is based on a reversible heat pump which provides both heat for space heating (in winter) and cold for air conditioning (in summer). Electricity is imported from the utility grid at the same conditions of the previous system.

3.2. Decentralised systems

Solution C1 produces combined heat and power by using a gas engine technology (with 42% electrical efficiency). Cold for air conditioning is generated by means of an absorbing refrigerator making use of the "cogenerated" heat.

Solution C2 has the same configuration as C1 but combined heat and power is produced by a gas turbine (with 35% electrical efficiency) instead of a gas engine.

C1 and C2 are "open" solutions. Power plants are sized in order to satisfy the maximum heat demand so that they generate power in excess of customer needs. This excess power is exported to the utility grid and accounted for in terms of avoided fuel consumption of the large power generation (CCGT with 54% electrical efficiency minus the percentage of electricity transport losses).[10] Therefore, net primary energy is equal to DG fuel consumption minus the avoided fuel consumption of the CCGT (including energy losses due to electricity transport).

D1 and D2 systems are "isolated" since they do not involve importing/exporting electricity from/to the utility grid. Small power plants are sized in order to satisfy the maximum customer needs of electricity. This implies that the amount of "cogenerated" heat is not sufficient to satisfy energy needs for domestic heating and air conditioning. We assume that the remaining heat (during the winter) and cold (during the summer)

[10] In the case of "open" solutions, only the transport losses (2%) must be accounted for, because this kind of supply does not bypass the electricity distribution costs. That is, "open" solutions bypass transmission losses and do not bypass the distribution losses.

are supplied by a reversible heat pump using "cogenerated" power. Solution D1 uses a gas engine whereas solution D2 a gas turbine.

It is important to underline that "isolated" does not mean disconnected from the distribution grid. Even in this case (unless one accepts a very low level of supply reliability), there must be the connection to the electricity distribution grid to provide ancillary services (i.e. back-up power) and permit the occasional exchange of electricity.

Note that we compare DG to the CCGT (at 54% electrical efficiency), which is the best generating technology from social costs (internal plus external costs) point of view, and not to the existing average mix of thermal generating plants (whose average electrical efficiency is much lower). This choice is consistent with the need to compare centralised and decentralised models in terms of (social) long-run marginal costs. For the same reason, we consider the applications of gas fired DG technologies (modern gas turbine and gas engine at 35% and 42% electrical efficiency, respectively).

Concerning gas turbines, an efficiency of about 35% is near to the maximum that could be realised with an all-metallic single-shaft low-pressure ratio engine. A long-term microturbine efficiency goal of 40% has been mentioned in many papers and articles, but to achieve this an engine with ceramic hot end components would be required, but such technology is not commercially foreseen for several years.

Concerning gas engines, 42% is the efficiency foreseen in 2005 for gas engines with a size lower than 5 MW (engineers predict a target of 45–47% in the future).

Finally, 54% electrical efficiency is the already available performance of the new large CCGT, but engineers predict significant improvement (linked to the improvements in the gas turbine) in the next few years (efficiency up to 56–58%).

In the sensitivity analysis, we will use 40%, 47% and 56% efficiency for gas turbine, gas engine and CCGT, respectively, to take into account the medium and long-term technological progress.[11]

3.3. Results

By following the method illustrated in Appendix A (Tables A.5–A.8), it is now possible to obtain the primary energy consumption of the different energy supply solutions. Table 1 shows that the primary energy consumption of the decentralised solutions is always lower than that of the conventional (A) centralised solution and depends considerably on technologies and locations. Energy saving is higher in Milan where the climate conditions are more favourable to combined heat and power generation (high ratio of heat and electricity needs) and the reciprocating engine always performs better than the gas turbine. In the best cases, energy saving can reach 30–40%, a value high enough to encourage us to continue our analysis in order to verify DG performance in terms of social benefits.

However, since the performance of the "open" solutions is similar to that of the "isolated" one (slightly higher, in the case of the gas engine, and slightly lower in the case of the gas turbine), we can strength our treatment by analysing only the latter. We will fully justify this choice at the end of the paper (Sections 6 and 7), when we will be able to demonstrate that "isolated" solutions are much better than the "open" one, in terms of environmental impact.

4. Internal costs and benefits

4.1. Methodology

In this section, we illustrate the methodology used to assess DG internal costs and benefits. Following the general approach illustrated above, we have to assess the internal costs of centralised and decentralised systems.

The crucial step in assessing the internal costs is to simulate the optimal prices of electricity and natural gas which are inputs of the centralised (both) and decentralised (only natural gas) supplies (recall Fig. 1). Given the characteristics of the demand and supply of such inputs (demand varies significantly over time and energy storage is very difficult and costly), we have to simulate their long-run marginal costs of supply at all segments of the industry cycle where there exists the so-called peak-load pricing problem.[12]

Before proceeding, it is important to underline that setting optimal prices equal to long-run marginal costs implicitly implies that we are supposing constant return to scale or the possibility of transfers from the state to the operator. The first assumption is unreal because we face increasing return to scale. Thus optimal prices should be calculated by maximising social welfare under the firm profit constraint. The second would require taking into account the social impact of the public transfer. Nevertheless, the introduced approximations have only a marginal impact on the results of this analysis.

[11] For the expectations of future small DG electrical efficiency, see also Resource and Dynamic Corporation (1999) and McDonald (2003).

[12] Unfortunately, since we cannot apply a similar procedure in the case of natural gas and DG equipment productions, we are forced to keep their market prices. However, this does not reduce the significance of our analysis since, as we shall later see, DG benefits are almost insensitive to natural gas prices and only slightly sensitive to DG investment costs.

Table 1
Primary energy consumption and energy saving

	North (Milan)			South (Palermo)		
	Natural gas consumption (MWh/y)	Net electricity imported from the grid (MWh/y)	Primary energy (MWh/y)	Natural gas consumption (MWh/y)	Net electricity imported from the grid (MWh/y)	Primary energy (MWh/y)
Residential building						
Centralised solutions						
Conventional (A)	2536	1414	5481	1159	1545	4378
Electrical heat pump (B)	442	1959	4524	442	1651	3882
B/A			0.83			0.89
Decentralised solutions						
"*Open*" *solutions*						
Gas engine (C1)	10115	−3460	3461	8134	−2628	3080
C1/A			0.63			0.70
Gas turbine (C2)	9764	−2629	4707	8139	−2061	4176
C2/A			0.86			0.95
"*Isolated*" *solutions*						
Gas engine (D1)	3800	0	3800	3289	0	3289
D1/A			0.69			0.75
Gas turbine (D2)	4276	0	4276	3758		3757
D2/A			0.78			0.86
Hospital						
Centralised solutions						
Conventional (A)	19466	17757	56460	10706	18218	48662
Electrical heat pump (B)	4018	21739	49307	4018	19349	44330
B/A			0.87			0.91
Decentralised solutions						
"*Open*" *solutions*						
Gas engine (C1)	76042	−18798	39893	59617	−11899	36734
C1/A			0.71			0.75
Gas turbine (C2)	73266	−12503	49221	58931	−7486	44535
C2/A			0.87			0.92
"*Isolated*" *solutions*						
Gas engine (D1)	41668	0	41668	37443	0	37443
D1/A			0.74			0.77
Gas turbine (D2)	46910	0	46910	42286	0	42286
D2/A			0.83			0.87

4.1.1. The model

To simulate optimal prices of the electricity and gas inputs, we do not follow the conventional peak-load pricing approach whose outcome is a vector of prices, each corresponding to a specific time period of demand.[13] We set out a method that directly provides the unit price (per unit of energy consumed) of a typical annual supply by utilising a function representing the customer demand profile over time.

The reasoning is the following. Suppose a new residential building has been built. The question is: what is the long-run marginal cost of delivering energy to this new building (new customer)?

Answering this question requires evaluating the additional expenses the utility must sustain to serve the new customer with a given consumption profile over time.

Suppose this utility provides the input k (e.g. electricity) and is vertically integrated over several stages (e.g. in the case of electricity, power generation,

[13] As regards pricing regulation, we have analysed the traditional literature on peak-load pricing methodology originally set out by Steiner (1957) and Boiteux (1956) and later fully developed by other authors (see Pressman, 1970; Crew and Kleindorfer, 1986). We have made very few incursions in the world of non-linear tariffs. Worth mentioning is the study by Electricité de France-Service des Etudes Economiques Générales (1979) which provides a useful application of marginal cost pricing to the case of electricity supply.

electricity transport and electricity distribution and supply).

We assume this utility initially faces a capacity demand curve $P^k(H)$ which describes the classical load duration curve with H the number of hours of the year in which the capacity demand is higher than P^k.

Let $c_i^{km}(H) = f_i^{km} + v_i^{km}H$ be the annual cost of using a unit of capacity for H hours per year (ith technology) and Γ_1^{km}, Γ_2^{km} and Γ_3^{km} the best available technologies in the stage m (for the sake of simplicity and without loss of generality, we consider, for the moment, only three technologies) with $f_1^{km} < f_2^{km} < f_3^{km}$ and $v_1^{km} > v_2^{km} > v_3^{km}$ (the fixed and variable cost coefficients, respectively).

Given the cost functions and the load duration curves in Fig. 2, the minimum cost C^k of supplying the annual amount of energy $E^k = \int_{H_0^{km}}^{H_3^{km}} P^k(H)\,\mathrm{d}H$ is equal to the sum of the minimum cost C^{km} in each stage of the industry k (e.g. in the case of the electricity industry, the minimum cost of power generation plus the minimum cost of electricity transport plus the minimum cost of electricity distribution and supply). In order to calculate C^{km}, notice that (from the cost functions in Fig. 2) Γ_1^{km} is the best (minimum cost) technology in the range from H_0^{km} to H_1^{km}, Γ_2^{km} the best technology in the range from H_1^{km} to H_2^{km} and Γ_3^{km} the best technology in the range from H_2^{km} to H_3^{km}. Thus, the minimum cost configuration implies that Γ_1^{km}, Γ_2^{km} and Γ_3^{km} provide the amounts of energy corresponding to the areas (Fig. 2) $P_2^{km}CP_1^{km}$, $P_3^{km}BCP_2^{km}$, $H_0^{km}H_3^{km}ABP_3^{km}$, respectively.

Now assume that the utility must supply energy to a new customer with a demand profile $\Delta P^k(H) = \bar{P}^k(H) - P^k(H)$ where $\bar{P}^k(H)$ is the new load duration curve. Furthermore, suppose that this utility perfectly knows the customer demand profile (absence of uncertainty) and that is able to keep the cost minimisation (optimisation of plant mix). As above, from Fig. 2, the minimum cost $\bar{C}^k$ of supplying the amount of energy $\bar{E}^k = \int_{H_0}^{H_3} \bar{P}^k(H)\,\mathrm{d}H$ is equal to the sum of the minimum cost of power generation $\bar{C}^{km}$ in each stage of the industry k. Again, in order to calculate $\bar{C}^{km}$, notice that (from the cost functions in Fig. 2) Γ_1^{km} is the best (minimum cost) technology in the range from H_0^{km} to H_1^{km}, Γ_2^{km} the best technology in the range from H_1^{km} to H_2^{km} and Γ_3^{km} the best technology in the range from H_2^{km} to H_3^{km}. Thus, the minimum cost configuration implies that Γ_1^{km}, Γ_2^{km} and Γ_3^{km} provide the amounts of energy corresponding to the areas $(P_2^{km} + \Delta P_2^{km})\bar{C}(P_1^{km} + \Delta P_1^{km})$, $(P_3^{km} + \Delta P_3^{km})\overline{BC}(P_2^{km} + \Delta P_2^{km})$, $H_0^{km}H_3^{km}\overline{AB}(P_3^{km} + \Delta P_3^{km})$, respectively (Fig. 2).

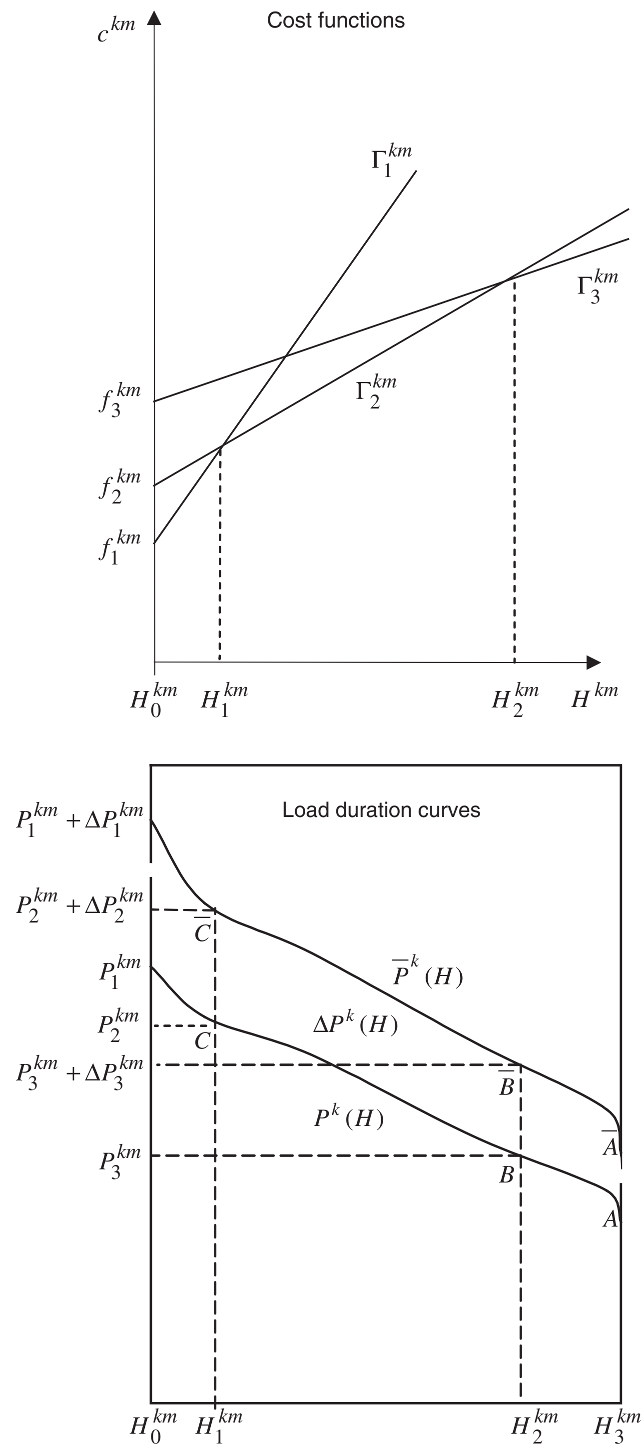

Fig. 2. Technology cost functions and load duration curves (k, industry; m, stage).

Given C^{km} and $\bar{C}^{km}$, taking into account that (from cost functions in Fig. 2)

$H_1^{km} = (f_2^{km} - f_1^{km})/(v_1^{km} - v_2^{km})$ and

$H_2^{km} = (f_3^{km} - f_2^{km})/(v_2^{km} - v_3^{km})$

and generalising to n technologies, the marginal cost (the additional expenses due to the new customer) will be the difference between $\bar{C}^k$ and C^k:

$$\Delta C^k = \bar{C}^k - C^k = \sum_m \left[f_1^{km} \cdot \Delta P_1^{km} + \sum_{i=1}^{n} v_i^{km} \cdot \int_{H_{i-1}^{km}}^{H_i^{km}} \Delta P^k(H)\,\mathrm{d}H \right], \quad (1)$$

where $H_n^{km} = H_n^k = H_n = 8760\,\mathrm{h}$, $H_0^{km} = H_0^k = H_0 = 0 \quad \forall k, m$ and $\Delta P_1^{km} = \Delta P_1^k \quad \forall k, m$.

Eq. (1) can be modified in order to obtain an approximate formulation very useful for our purpose. Assume a new customer with annual consumption $\tilde{E}^k$ of the input k and contractual capacity $\tilde{P}^k$ (maximum customer need). Let $\Phi^k(\tilde{H}^k) \cdot \tilde{P}^k$ be the measure of his responsibility in inducing the increase in peak capacity, where $\tilde{H}^k = \tilde{E}^k / \tilde{P}^k$ is the equivalent number of full consumption hours per year and $\Phi^k(\tilde{H}^k)$ is the peak probability consumption, that is the probability the new customer might consume during the peak hours, with $\Phi^k(\tilde{H}^k) \in [0, 1]$, $\mathrm{d}\Phi^k(\tilde{H}^k)/\mathrm{d}\tilde{H}^k > 0$ and $\mathrm{d}^2\Phi^k(\tilde{H}^k)/\mathrm{d}\tilde{H}^{k^2} < 0 \quad \forall \tilde{H}^k \in [\tilde{H}_0^k = 0, \tilde{H}_n^k = 8760]$.

Then, we can assume $f_1^{km} \cdot \Delta P_1^k \cong f_1^{km} \cdot \Phi^k(\tilde{H}^k) \cdot \tilde{P}^k$ and Eq. (1) becomes

$$\Delta C^k \cong \Delta \tilde{C}^k = \sum_m [\mu^{km} \cdot \tilde{E}^{km} + f_1^{km} \cdot \Phi^k(\tilde{H}^k) \cdot \tilde{P}^k], \quad (2)$$

where

$$\mu^{km} = \frac{\sum_{i=1}^{n} v_i^{km}(H) \int_{H_{i-1}^{km}}^{H_i^{km}} \Delta P^k(H)\,\mathrm{d}H}{\int_{H_0^{km}}^{H_n^{km}} \Delta P^k(H)\,\mathrm{d}H} \quad (3)$$

is the average variable component with $\tilde{E}^k = \int_{H_0^{km}}^{H_n^{km}} \Delta P^k(H)\,\mathrm{d}H$ and $H_n^{km} = H_n^k = H_n = 8760\,\mathrm{h}$, $H_0^{km} = H_0^k = H_0 = 0$.

From Eq. (2) it is possible to express the optimal price per unit of consumption as

$$p^k = \frac{\Delta \tilde{C}^k}{\tilde{E}^k} = \sum_m \left[\mu^{km} + f_1^{km} \cdot \frac{\Phi^k(\tilde{H}^k)}{\tilde{H}^k} \right], \quad (4)$$

where μ^{km} and f_1^{km} are respectively the variable and fixed cost coefficients in the m stage of k industry and $\Phi^k(\tilde{H}^k)$ is the peak probability demand of the customer (with $\tilde{H}^k = \tilde{E}^k / \tilde{P}^k$).

Now we are able to apply this model to the case of natural gas ($k = g$) and electricity ($k = e$) industries. Natural gas industry includes the following stages: gas production ($m = gp$), gas storage and modulation ($m = gsm$), gas transport ($m = gT$), gas distribution ($m = gD$) and gas supply ($m = gsp$). Electricity industry includes: large power generation ($m = eG$), electricity transport ($m = eT$), medium voltage electricity distribution ($m = eD_{MV}$); low-voltage electricity distribution ($m = eD_{LV}$); electricity supply ($m = esp$). For example, f_1^{eG} is the fixed cost coefficient of the peak technology in the power generation stage of the electricity industry and μ^{gT} is the variable cost coefficient in the transport stage of the natural gas industry.

We assume $\Phi^k = 1$ in the following stages of natural gas and electricity industries: gas distribution and gas supply; electricity supply and low-voltage electricity distribution. In these stages there is not, in fact, a problem of peak load pricing (or is less important), that is a problem of allocating common fixed costs between different customers with different demand profile (peak-off peak consumption) over time. This also explains why we have previously distinguished between medium voltage and low-voltage segments of the electricity distribution stage.[14]

By using Eq. (4) we can now express the optimal prices of natural gas (p^g) and electricity (p^e), respectively (the exhaustive legend of the parameters of the equations below is reported in Table A.9 of Appendix A (together the values of all parameters and variables):

$$\begin{aligned} p^g = \mu^{gp} &+ \left[\beta \cdot \mu^{gsm} + f_1^{gsm} \cdot \frac{\Phi^g(\tilde{H}^g)}{\tilde{H}^g} \right] \\ &+ \left[\mu^{gT} + \delta^{gT} \cdot \frac{\Phi^g(\tilde{H}^g)}{\tilde{H}^g} \right] \\ &+ \left[\mu^{gD} + f_1^{gD} \cdot \frac{1}{\tilde{H}^g} \right] + \left[\mu^{gsp} + f_1^{gsp} \cdot \frac{1}{\tilde{H}^g} \right], \end{aligned} \quad (5)$$

$$\begin{aligned} p^e = &\left[\mu^{eG} + f_1^{eG} \cdot \frac{\Phi^e(\tilde{H}^e)}{\tilde{H}^e} \right] + \left[\mu^{eT} + f_1^{eT} \cdot \frac{\Phi^e(\tilde{H}^e)}{\tilde{H}^e} \right] \\ &+ \left[\mu^{eD_{MV}} + f_1^{eD_{MV}} \cdot \frac{\Phi^e(\tilde{H}^e)}{\tilde{H}^e} \right] \\ &+ \left[\mu^{eD_{LV}} + f_1^{eD_{LV}} \cdot \frac{1}{\tilde{H}^e} \right] + \left[\mu^{esp} + f_1^{esp} \cdot \frac{1}{\tilde{H}^e} \right], \end{aligned} \quad (6)$$

where β in Eq. (5) is the incidence of the working gas,[15] $\mu^{eD_{MV}} + \mu^{eD_{LV}} = \mu^{eD}$ and μ^{gp} is the price of the primary energy source (natural gas).

Furthermore, the problem of optimising a mix of supply technologies (peak, off-peak) concerns only the power generation stage. In all other stages, in fact, there is only one technology. In the case of power generation, we consider two kinds of plants: a large gas turbine

[14]The topological configuration of the low-voltage electricity network and the low-pressure gas network is prevalently radial (at least in Italy). Therefore, the problem of sharing fixed costs (depending on "over time" profile of consumption, peak/off peak) is less relevant than in the case of electricity and gas transport or power generation.

[15]Working gas is the part of natural gas which is available for storage and modulation. The other part is the "cushion gas" which has the function to keep in pressure the storage gas field. Thus, only working gas must be taken into account for the variable costs.

(open cycle) as the peak technology; a large CCGT (with 54% electrical efficiency) as the off-peak technology. These assumptions are consistent with the current situation in Italy (and in several other countries). The large gas turbine is the typical marginal peak technology. The CCGT is the best available technology from social costs point of view (internal plus external costs). Thus, the fixed component of the power generation stage (f_1^{eG}) is equal to the fixed cost of the peak large gas turbine while the variable component (μ^{eG}) is obtained by using Eq. (3), for the case of two technologies (the values are reported in Table A.9 of Appendix A).

We can finally find the expression of the internal costs ($INTC$), by adding together the customer expenses for electricity and gas inputs, the operation and maintenance costs (discounted over time (t), with r discount rate) and the investment costs IC. We assume the year as the base time unit and a time period $T_1 = 20$ years (the plant lifetime, supposed the same for all plants). All parameters are assumed constant over time.

In the case of centralised systems, given the prices of electricity and gas inputs p^e and p^g from Eqs. (5) and (6), the annual consumption of electricity and gas ($\tilde{E}^e_{centr}, \tilde{E}^g_{centr}$), the investment costs IC_{centr} and the operation and maintenance costs OM_{centr} we get

$$INTC_{centr} = \int_{t=0}^{T_1} [p^g(\tilde{H}^g) \cdot \tilde{E}^g_{centr} + p^e(\tilde{H}^e) \cdot \tilde{E}^e_{centr} + OM_{centr}] \cdot e^{-r \cdot t}\, dt + IC_{centr}. \quad (7)$$

In the case of decentralised systems, we have to take into account the cost of grid interconnection[16] to the electricity grid ($\delta^e \cdot P_e^*$), where δ^e is the cost of interconnection per unit of DG power plant size and P_e^* this DG power plant size. Let $\tilde{E}^g_{DG}$ be the annual gas consumption, IC_{DG} the investment costs and OM_{DG} the operation and maintenance costs, the internal costs of DG will be

$$INTC_{DG} = \int_{t=0}^{T_1} [p^g(\tilde{H}^g) \cdot \tilde{E}^g_{DG} + \delta^e \cdot P_e^* + OM_{DG}] \times e^{-r \cdot t}\, dt + IC_{DG}, \quad (8)$$

where $\tilde{H}^g$ and $\tilde{H}^e$ are the equivalent number of full consumption hours for gas and electricity consumption, respectively. IC_{centr} includes investments (turn-key) in end-use technologies (compressing refrigerator, heat pump, condensing boiler, etc.). IC_{DG} includes investments (turn-key) in DG plant, heat pump and ancillary equipment (see Tables A.3 and A.4 of Appendix A). All the parameter values of the models are reported in Table A.9 of Appendix A and refer to average values in Italy calculated by elaborating data and information provided by the Italian Energy Authority.[17] Note that we assume $\mu_m = 0$ for the gas distribution, gas supply and electricity supply stages. These assumptions are consistent with the nature (almost prevalently fixed) of the costs in these stages.

Finally concerning $\Phi^k(\tilde{H}^k)$ the following functions, typical of the Italian market, have been adopted: $\Phi^e(\tilde{H}^e) = 1 - e^{-0{,}00052 \cdot \tilde{H}^e}$ for electricity and $\Phi^g(\tilde{H}^g) = 1 - e^{-0{,}0016 \cdot \tilde{H}^g}$ for natural gas.

Given Eqs. (7) and (8) and according to the methodological approach, DG benefits can be expressed as

$$INTB_{DG} = 1 - \frac{INTC_{DG}}{INTC_{centr}}. \quad (9)$$

4.2. The results

Table 2 illustrates the results obtained from applying Eqs. (7) and (8) and using the data reported in Table A.9 of Appendix A.[18] From the table, it clearly emerges that the framework of DG competitiveness is not very encouraging from the internal benefits point of view.

Concerning the residential sector, DG internal costs are always higher than those of centralised supply (both conventional and advanced).

With regard to the hospital, DG seems to be (slightly) competitive only in Milan and compared to the conventional centralised solution. In all other cases, DG never provides internal benefits, although the situation is slightly better than that of the residential sector.

In conclusion, the internal cost–benefit analysis does not confirm the framework emerging from energy efficiency comparison. Even though DG assures significant levels of energy saving (up to 30%), its costs are still higher (on average) than those of centralised supply. To be more specific, saving on fuel and electricity transport costs are counterbalanced by higher investment costs.[19]

[16] The typical cost of grid interconnection ranges from 50 to 200 USD/kW depending on the size of the generator, application, and utility requirements. The complexity of the interface increases with the level of interaction required between the DG unit/owner and the electrical grid. See Arthur D. Little (1999).

[17] See AEEG (1999–2002).

[18] Concerning the conventional discount rate for the internal costs, we have chosen a value in the range of 3–8% (namely 4%).

[19] Concerning total investment costs of small CHP DG, several sources of information can be reported. We advise to consult the website of the California Energy Commission (http://www.energy.ca.gov/distgen/) and, for the gas engine, the results of the empirical analysis reported in Madlener and Schmid (2003). With regard to O&M costs, we use a coefficient equal to 0.015 and 0.01 €/kWh (per kWh of total output) for the gas engine and gas turbine, respectively. This interval corresponds to a range from 60 to 70 €/kWe, which is consistent with the literature on data referring to CHP plants. See Strachan and Dowlatabadi (2002) and http://www.energy.ca.gov/distgen/.

Table 2
Internal costs (k€)

	North (Milan) (*INTC*)					South (Palermo) (*INTC*)				
Discounted:	Fuel costs	Electricity costs	O&M costs	Invest. costs	Total costs	Fuel costs	Electricity costs	O&M costs	Invest. costs	Total costs
Residential building										
Centralised solutions										
Conventional (A)	1162.6	1516.9	182.2	441.2	3302.9	647.4	1656.5	194.1	470.0	2968.0
Electrical heat Pump (B)	161.4	2051.4	229.9	556.6	2999.3	161.4	1758.2	247.3	598.7	2765.6
B/A					0.91					0.93
Decentralised solutions										
Gas engine (D1)	1672.5	0.0	706.4	1171.4	3550.3	1598.2	0.0	611.5	1296.2	3505.9
D1/A					1.07					1.18
D1/B					1.18					1.27
Gas turbine (D2)	1734.6	0.0	529.9	1190.9	3455.4	1707.9	0.0	465.6	1286.2	3459.7
D2/A					1.05					1.17
D2/B					1.15					1.25
Hospital										
Centralised solutions										
Conventional (A)	8119.5	16291.4	1077.9	2610.1	28098.9	4540.8	17031.5	1390.9	3367.7	26330.8
Electrical heat pump (B)	1126.8	19901.0	1537.8	3723.6	26289.2	1126.8	18117.1	1535.1	3717.1	24496.1
B/A					0.94					0.93
Decentralised solutions										
Gas engine (D1)	14985.4	0.0	5163.9	7201.5	27350.9	14477.8	0.0	4640.3	7773.3	26891.4
D1/A					0.97					1.02
D1/B					1.04					1.10
Gas turbine (D2)	15752.7	0.0	4360.2	7349.1	27462.0	15175.0	0.0	3930.4	7934.4	27039.9
D2/B					1.04					1.10
D2/A					0.98					1.03

These results are based upon specific (but consistent with the literature) assumptions about investment costs, electrical efficiency and other parameters. Later, we will check their robustness by carrying out a sensitivity analysis (see Section 7), where we will also account for DG benefits due to increased power reliability.

However, the fact that DG internal costs are higher than those of centralised supply is not very surprising. Conventional DG is generally subsidised and generally considered competitive only in specific market segments (industrial sectors) although several authors emphasise its potential when used to provide combined heat and power, even in the residential and service sectors. Therefore, the question shifts to the extent of DG environmental benefits which commonly inform the environmental policies supporting DG deployment.

5. External costs and benefits

5.1. Methodology

Energy production and consumption cause damage to a wide range of receptors, including human health, natural ecosystem, materials, monuments, etc. Such damage is referred to as external costs since they are not reflected in the market price of energy. They are due to various agents: atmospheric and non-atmospheric pollutants, accidents and occupational diseases, noise, etc. Our analysis only considers the effects of the main atmospheric pollutants (which represent the relevant part of the total damage).

The total external cost $EXTC$ can be expressed as (for centralised and decentralised supplies, respectively)

$$EXTC_{centr} = \sum_z \alpha_z^{centr} \bar{Q}_z^{centr}, \tag{10}$$

$$EXTC_{DG} = \sum_z \alpha_z^{DG} \bar{Q}_z^{DG}, \tag{11}$$

where z is a generic pollutant and

$$\overline{Q}_z = \int_{t=0}^{T_1} Q_z(t) \mathrm{e}^{-rt} \, \mathrm{d}t \tag{12}$$

is the discounted amount of z pollutant emitted during the plant operating life, with $Q_z(t)$ the amount emitted of z pollutant in t, and

$$\alpha_z = \frac{\int_{t=0}^{T_1} \int_{\vartheta=0}^{T_2} D_z(t, \vartheta) \mathrm{e}^{-r\vartheta} \, \mathrm{d}t \, \mathrm{d}\vartheta}{\int_{t=0}^{T_1} Q_z(t) \mathrm{e}^{-rt} \, \mathrm{d}t} \tag{13}$$

is the unit external cost (per unit of pollutant emitted). $D_z(t, \vartheta)$ is the monetary value of the damage in time ϑ due to the emissions of the z pollutant in time t, with $D_z(t, \vartheta) = 0 \forall t > \vartheta$. Like internal cost methodology, we assume the year as the base time unit. T_1 is the plant lifetime (20 years) and T_2 is the time horizon in which the monetary damages are calculated (100 years, in the case of global warming (GW)).

Given Eqs. (10) and (11) and according to the methodological approach, DG benefits are

$$EXTB_{DG} = 1 - \frac{EXTC_{DG}}{EXTC_{centr}}. \tag{14}$$

In order to calculate the α_z coefficients, we use the dissemination process of the ExternE project briefly described below.

The ExternE methodology[20] follows the *bottom-up* approach and is based on a *step-by-step* procedure. In fact, it requires dealing with cascade phases: (1) the determination of the emissions for each stage of the fuel cycle (from the production of primary input to the output production); (2) a simulation of the dispersion of the pollutants both on local and regional scales; (3) the identification of all the receptors; (4) the calculation of the impact (by means of the application of the "dose–response" functions); (5) where possible, the economic evaluation of such an impact.

The pollutants taken into consideration are solid, liquid and gaseous residues. The main impact is due to the emissions of CO_2, SO_x, NO_x and particulate (PM_{10}).

The damage taken into consideration includes the effects on public health, agriculture, forests (acid rain), the ecosystem in general, materials (deterioration of buildings and monuments) and the damage related to GW as a result of GHG (greenhouse gases) emissions. Dose–response functions provide the marginal damage caused by increment of concentration due to plant emissions. They can be linear, non-linear and with a threshold. "Willingness to pay or to accept" is the standard measure of the value in environmental economics adopted throughout the ExternE project.

The analysis conducted in the ExternE Project shows that the uncertainties of external cost assessment are significant, especially as regards GW estimations. Part of this uncertainty depends on social-political choices which mainly reflect on the discount rate choice (another important ethical-political choice concerns the value of statistical life), while the remaining part is statistical (scientific nature). Statistical uncertainty regards data uncertainty (e.g. slope of a dose- response function, cost of a day of restricted activity, and deposition velocity of a pollutant, etc.) and model uncertainty (assumptions about causal links between a pollutant and a health

[20] The ExternE approach is one of the most recent and reliable methodologies in this field. It was developed by a group of leading European and US research centers with the financial support of the EU (DG XII). Valette (1995) briefly describes the methodological approach and reports the results when it was first implemented. For more recent information, see the web-site of ExternE (http://www.externe.info/).

impact, assumptions about form of a dose–response function, choice of models for atmospheric dispersion and chemistry, models of simulating the temperature increase and its profile over time due to GHG emissions, etc.).

In order to isolate the problem of political uncertainty (the role of discounting in assessing external costs), which mainly refers to GW estimations, our analysis deals separately with the impact due to local–regional pollutants (mainly SO_x, NO_x and PM_{10} emissions) and the GW (due to GHG emissions).

5.1.1. Local and regional pollutants (LR)

Political uncertainty (the choice of discount rates), which is crucial in the case of the global effects, is less important in the case of local–regional impacts. Most local–regional impacts of air pollution are, in fact, fairly immediate and discounting is not significant.[21] This means that we can assume $t = \vartheta$and $T_1 = T_2$, in Eq. (13). Moreover, since $Q_z(t)$ is the same in every year (same amount of electricity and gas consumption) and the "dose–response" functions (of the ExternE model) do not change over time (year), $D_z(t, \vartheta)$ can be assumed constant over time. In consequence, from (13), α_z would not depend on discount rate.

In order to evaluate the external costs coefficients we have used the results of the ExternE dissemination process (the application of the same methodology to different plants and locations across Europe). These results show that there are two effects which determine significant differences in external cost coefficients (the source of pollution being equal) and are important in the case of DG: the macro-localisation of the plant (in our case, north or south of Italy) and its micro-localisation (urban or extra-urban location). Small DG plants are generally located, in fact, in urban areas while large power plants in extra-urban areas.

Regarding macro-localisation effects (north of Italy versus south of Italy) we have used the results of the ExternE dissemination process in Italy[22] (the application of the same methodology to different plants across the country). These results point out how external costs per unit of pollutant emitted are, in the north of Italy (Milan), higher than the average Italian value (+38% for SO_x; +59% for PM_{10} and +77% for NO_x) and, in the south of Italy (Palermo), lower than the average value (−34% for SO_x; −24% for PM_{10} and −39% for NO_x).

With regard to micro-localisation effect (urban versus extra-urban locations) we have used the results of the external costs of transport,[23] which provide a comparison between urban and extra-urban locations. Urban areas involve an environmental impact higher than that of the extra-urban areas. In fact, the high increases in pollutant concentration (close to the source of pollution) occur in highly populated areas and seriously damage human health. With the macro-localisation being equal, these effects cause an environmental impact (per unit of pollutant emitted) of DG (which is generally located in an urban area) greater than that of a large power plant (which is generally located in an extra-urban area).

The influence of the local population density (urban areas) is considerable in the case of PM_{10} (urban cost is 150% higher than the extra-urban cost) and SO_x (urban cost is 37% higher than extra-urban cost) but it is much lower (in some cases inexistent) in the case of NO_x.[24] In this respect, we have to observe, however, that applying the results of transport to power generation might not be a correct approach. Indeed, transport emissions occur at the ground level so that the effect of pollutant atmospheric dilution (dispersion) is very low (much higher pollutant concentrations close to the source of pollution), compared to that of a power plant with a high stack. Consequently, environmental impact of transport (mainly health impact) is higher (being equal the amount of pollutant emitted) and DG micro-localisation effect might be overestimated.

Nevertheless, it is important to bear in mind that the stack of a small power plant in an urban area is much lower (around 20 m) than that of a large power plant (100–150 m). Thus, even DG emissions occur at a relatively low quota. ExternE simulations of SO_x impact[25] for different emission quotas (stack height) demonstrate that the difference between the ground level (transport) and the 20 m level (DG) is almost negligible (+5–10%). Therefore, using the results of the transport to evaluate micro-localisation effects of DG can be acceptable. The introduced approximation will have only a marginal impact on the overall results, also because of the extremely low emissions of particulate and SO_x (see Table A.2).

By using these data, we have obtained the values illustrated in Table 3. In this table the best guess[26] of the statistical distribution and the corresponding geometric standard deviation are reported.

DG and gas fired boiler values have been calculated by applying the coefficients previously described for

[21] The main exceptions are chronic health impacts and cancers which are important in the so-called chronic mortality from particulate. For the sake of simplicity, in our analysis, we disregard this effect because of the very low emissions of particulate. See European Commission (1999e).

[22] See Frigerio et al. (1995) and European Commission (1999c).

[23] See European Commission (1997).

[24] Most impact of NO_x is due to nitrate aerosols, which form in air (via chemical transformation) far to the source of pollution. Therefore, the share of local range of the total damage costs is only small and is almost independent on the local population density.

[25] See European Commission (1999a) and Rabl and Spadaro (1999).

[26] The best guess (i.e. the marginal cost with all parameters set at their central estimate) is a conservative estimate of the marginal cost of pollutant emissions.

Table 3
External costs per unit of pollutant (ExternE model)

	Local and regional effects (αh)		
	(SO_x) (€/kg)	(PM_{10}) (€/kg)	(NO_x) (€/kg)
Gas fired boiler and DG technologies			
Milan	20.3	51.1	18.6
Palermo	9.7	24.5	6.4
Large power plant (combined cycle)			
Italy	10.7	12.9	10.5
Geometric standard deviation (σ_g)	3–5	3–5	3–5

each pollutant to the Italian average value, corresponding to the large power plant. For example, in the case of SO_x in Milan, we have multiplied 10.7, the external cost coefficient of the large power plant, by $1.89 = 1.38 \cdot 1.37$.

The following conclusions can be drawn from this table. First, the impact of local and regional pollutants largely depends on plant geographic localisation. All other conditions being equal, external costs are much lower in Palermo than in Milan. This is due to the micro and macro-localisation effects (thus also confirming our preliminary intuition about the choice of geographic locations).

With regard to uncertainty, ExternE proposes a methodology which simplifies the treatment. In fact, the expression for the total damage is shown to be largely multiplicative, even though it involves a sum over receptors at different sites. For example, air pollution effect on health is

$$\text{Damage} = \Delta\text{pollution concentration} \cdot \text{population} \cdot \text{dose-response function} \cdot \text{economic valuation.}$$

Since the central limit theorem implies that the error distribution for multiplicative processes is likely to be approximately lognormal, one may be able to bypass the need for a detailed and tedious Monte Carlo calculation. In fact, following Rabl and Spadaro (1999), it may not be necessary to worry about details of the probability distributions, because they wash out in the final result thanks to the central limit theorem. Thus, it suffices to specify geometric mean [μ_g] and geometric standard deviations [σ_g], or equivalently, multiplicative confidence intervals about the geometric mean (which is usually close to the median): $[\mu_g/\sigma_g, \mu_g \cdot \sigma_g]$ for approximately 68% and, $[\mu_g/\sigma_g^2, \mu_g \cdot \sigma_g^2]$ for approximately 95%.

Thus, to the extent that the distribution of the results is lognormal, the geometric mean equals the median and the geometric standard deviation has a simple interpretation in terms of multiplicative confidence intervals around the median.

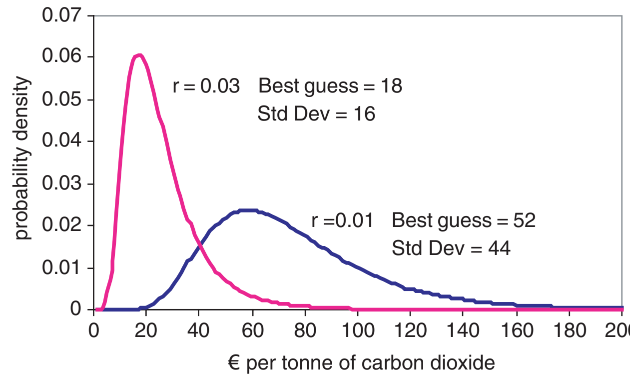

Fig. 3. Uncertainty regarding the marginal costs of carbon dioxide (r = discount rate). *Source*: European Commission (1999b).

For the reporting of uncertainties, the ExternE project chooses a simplified format, in terms of uncertainty labels. These labels are: A = high confidence, corresponding to $\sigma_g = 2.5-4$; B = medium confidence, corresponding to $\sigma_g = 4-6$; and C = low confidence, corresponding to $\sigma_g = 6-12$.

A variant of this presentation is to indicate the order of magnitude of the range (between upper and lower limits of the confidence intervals). Then label A corresponds to approximately 1 order of magnitude, label B to approximately 1.5 orders of magnitude, and label C to approximately 2 orders of magnitude, respectively, between upper and lower limits of 68% confidence interval. The ExternE project typically recommends for NO_x, SO_x and PM damages low and medium confidence intervals (labels A and B). More specifically, Rabl and Spadaro (1999) analyse several types of air pollution damage and show that the geometric standard deviation σ_g is in the range 3–5 (Table 3).

5.1.2. Global warming (GW)

It is apparently easier to assess the external cost coefficients of GW. The marginal damage (per unit of pollutant emitted) does not in fact depend on technology and plant localisation. Therefore, there is no need to analyse the ExternE dissemination process since it is sufficient to utilise the general estimations proposed by ExternE. Nevertheless, given the high uncertainty mentioned earlier, ExternE does not propose a single value but statistical distributions obtained by means of a series of simulations, each for a particular value of discount rate, and well fitted by lognormal functions.[27] ExternE suggests[28] using a discount rate ranging from

[27] These simulations are based on the use of the Montecarlo method and the FUND model. FUND is a model calculating GHG marginal damage. Its strengths are in dynamic and integrated analysis. See European Commission (1999a, b).

[28] Regarding the problem of discounting in environmental cost–benefit analysis, see European Commission (1999a, b).

Table 4
Emission rates and external costs per kWh of fuel

Sectors	Global effects[a]			Local and regional effects[a]				Total external costs (best guess) (r) (m€/kWh)	
	Emissions (g/kWh)	Global external costs (best guess) (r) (€/t CO_2)		Emissions (g/MWh)			Local and regional external costs (m€/kWh)		
	CO_{2eq}	1%	3%	(SO_x)	(PM_{10})	(NO_x)		1%	3%
Gas fired boiler[b]									
Milan	202.7 (14.0)	52	18	1.7	0.0	32.9	1.65 (1.00)	12.19	5.30
Palermo	202.7 (14.0)	52	18	1.7	0.0	32.9	1.23 (1.00)	11.77	4.88
DG technologies									
Gas fired engine									
Milan	195.1 (14.0)	52	18	1.0	4.9	359.1	7.95 (1.00)	18.10	11.46
Palermo	195.1 (14.0)	52	18	1.0	4.9	359.1	3.43 (1.00)	13.57	6.94
Gas turbine									
Milan	197.3 (14.0)	52	18	0.8	9.7	140.8	4.13 (1.00)	14.39	7.68
Palermo	197.3 (14.0)	52	18	0.8	9.7	140.8	2.15 (1.00)	12.41	5.70
Large power plant (combined cycle with SCR)									
Italy	193.7 (14.0)	52	18	0.9	8.8	13.1	1.28 (1.00)	11.33	4.75

[a]Within brackets emissions and external costs of exploration, production and transportation fuel cycle stages, assumed equal for all technologies.
[b]Emission rates refer to the best available technology. See European Commission (1999d). *Note*: r = discount rate.

1% to 3% whose probability distributions, reported in Fig. 3, will be directly used in our estimating model in order to take into account the effects of both statistical and political uncertainty.[29]

5.2. The results

Before showing DG external cost–benefit in terms of probability distribution, it is useful to give an idea of the weight of the single pollutants in determining the total external costs. For this purpose we use the best guess of the marginal costs of carbon dioxide (both for 1% and 3% discount rate) and the best guess of the marginal costs of local–regional pollutants. The results (obtained by using the values in Table 3 and the emission rates in Table A.2 of Appendix A) are reported in Table 4[30] which clearly shows that the total external costs sensibly depend on the variability of the marginal cost of carbon dioxide.

Given the estimates of the local and regional monetary damage reported in Table 3, the electricity and gas consumption described in Tables A.1 and A.9 and the probability distributions of global monetary damage reported in Fig. 3, we can now calculate the external DG benefits in terms of cumulative distributions (Figs. 4 and 5). We report the ratio of costs (DG costs divided by centralised costs) on the horizontal axis (the benefit is one minus the value of this indicator). The results are reported in terms of cumulative probability curves. These curves are very useful because they directly show the probability that external cost of DG could be lower than the external cost of centralised supply (the value on the vertical axis corresponding to the ratio of costs equal to one).

For the moment, since we are prevalently interested in showing the effect of global impact uncertainty, we do not take into account the statistical uncertainty about local–regional impacts. The influence of this uncertainty will be accounted for later, when we will attempt to evaluate the overall range of environmental benefit of DG.

The following conclusions can be drawn from these figures. First, the estimate dispersions are considerably lower than those of GW cost estimations themselves (in most cases the curve are almost vertical), so that DG social cost–benefit can be clearly identified.

Second, concerning the residential sectors, in the case of gas engines in Milan, there is a probability of around 50% (around 90% in the case of the gas turbine) that DG could provide benefits, with 1% discount rate and compared to the conventional centralised system. Nevertheless, this probability almost disappears using

[29]It is necessary to bear in mind that there are GHG other than carbon dioxide, such as CH_4 and N_2O. The specific contribution of these gases to global warming is higher than that of CO_2 but the amount emitted is much lower (of one order of magnitude). In order to take into account even these gases, emitted by fuel cycles, the equivalent CO_2 (CO_{2eq}) greenhouse potential is normally used. For a criticism of this procedure, see Schmaleense (1993).

[30]Note that the coefficients include not only the external cost of power plant operation but also the monetary damage due to the upstream stages of the fuel cycles (exploration, production, transportation, etc.).

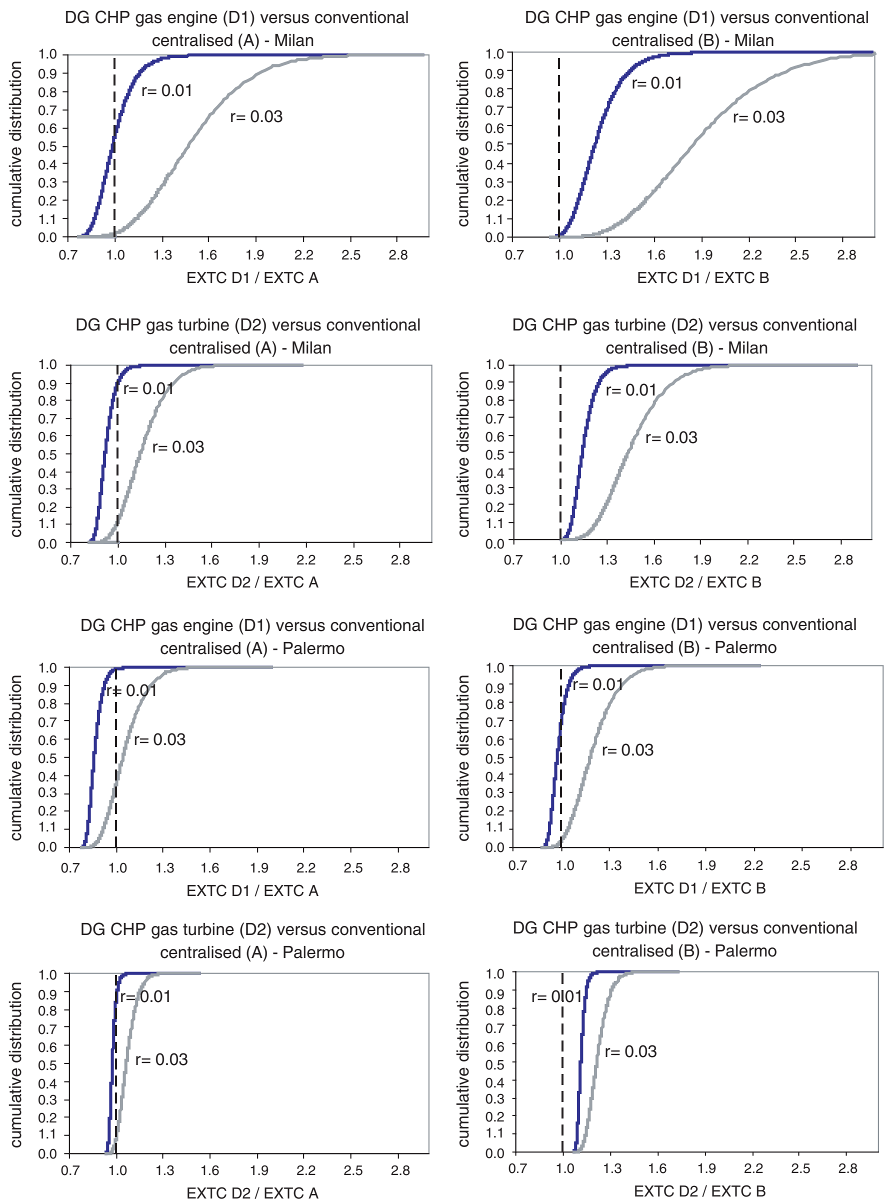

Fig. 4. DG external costs and benefits (residential building). *Note*: EXTC = external costs; A = conventional centralised (condensing boiler plus compressing refrigerator); B = advanced centralised (electrical heat pump); D1 = DG gas engine; D2 = gas turbine; CHP = combined heat and power generation.

3% discount rate. The picture is quite different when we compare DG to the heat pump (the advanced centralised system). Decentralisation never provides benefits at either the 1% or 3% discount rate. A similar result emerges from the gas turbine application. In Palermo, the situation is slightly better. There are significant benefits when we compare DG to conventional centralised supply and with 1% discount rate. But again DG does not provide significant environmental benefits compared to the heat pump (except for the gas engine but only with 1% discount rate).

Similar conclusions can be drawn from the figure regarding the hospital. In fact, there are no significant differences between the two applications. However, in Milan, the performance of the hospital is lower, whereas in Palermo is very similar in the case of the gas engine and slightly better in the case of the gas turbine.

It is important to underline that the macro and micro-localisation effects previously described have only a small impact on these results. They mainly regard, in fact, SO_x and PM_{10} whose emissions of DG and large power generation are similar and very low. The relevant part of DG low performance is due to the much higher DG emissions of NO_x (see Table A.2 of Appendix A), compared to those of CCGT. We have assumed, in fact, that the large power plant uses the selective catalytic reduction (SCR), as method of removing NO_x from the exhaust stream. SCR is highly effective and it is typically

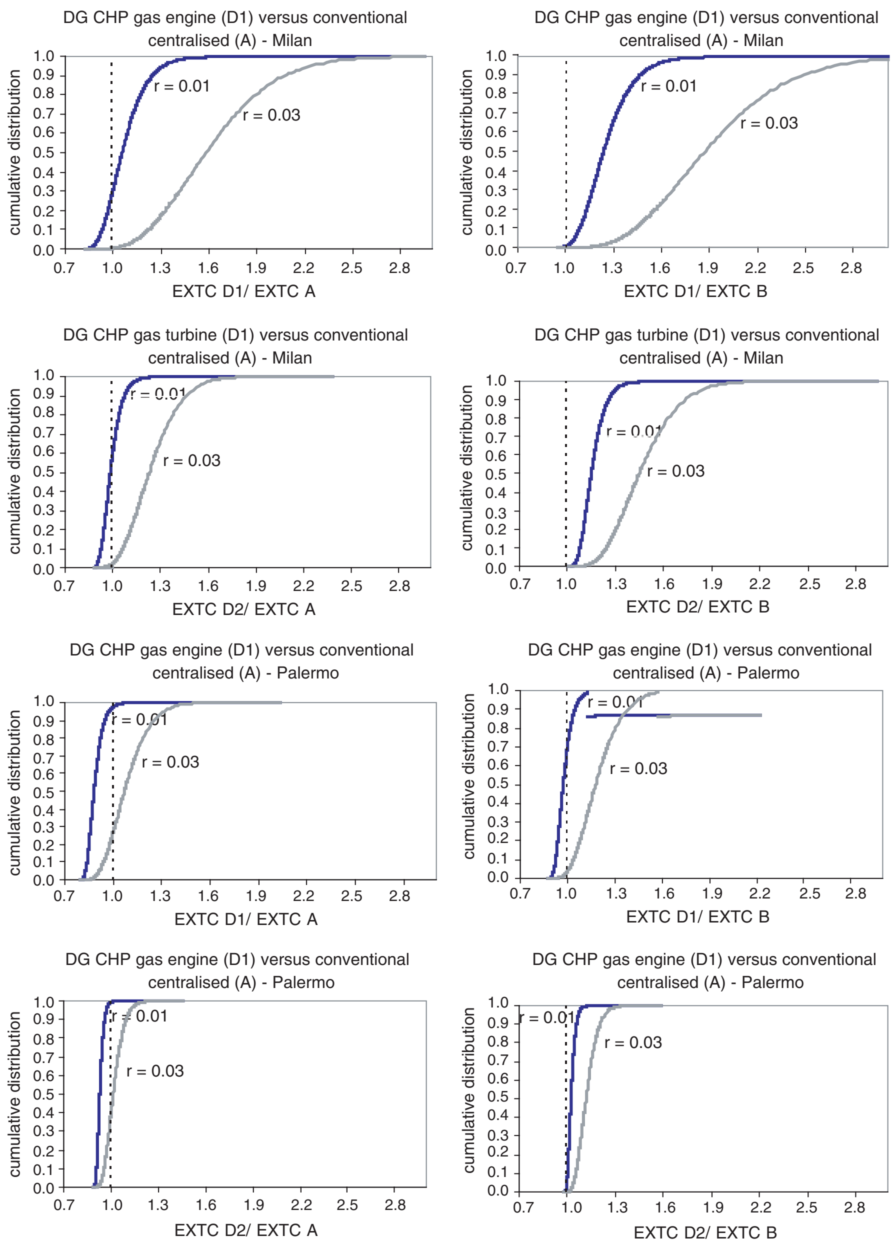

Fig. 5. DG external costs and benefits (hospital). *Note*: EXTC = external costs; A = conventional centralised (condensing boiler plus compressing refrigerator); B = advanced centralised (electrical heat pump); D1 = DG gas engine; D2 = gas turbine; CHP = combined heat and power generation.

used in large industrial and electric generating facilities. It makes use of toxic chemicals (e.g. urea, ammonia) and produces solid waste, two features which (apart from its high cost for small-scale applications) render it impractical for many DG applications.

In Table 5 we report the shared analysis of the difference between external costs of DG and centralised supply (for the case of the gas engine in Milan). As we can see, the low environmental performance of DG (external costs higher than those of centralised supply) is prevalently due to the higher non-GHG pollutant emissions (mainly due to higher NO_x emission rate) which counterbalance the positive effect of the lower GHG emissions (due to energy saving).

In conclusion, the analysis of the external costs seems to confirm the discouraging framework which already emerged from the assessment of the internal costs since small DG appears to be not (or low) competitive even from the environmental point of view (especially when compared to the advanced centralised solution, the heat pump). However, this time, the result is quite surprising, considering that the supposed environmental benefits generally inform the policies designed to support DG. This analysis would thus support the idea that such environmental policies are ambiguous since, by focusing on GW, they disregard the possible trade-off between the impact of local–regional pollutants (SO_x, NO_x, particulate, etc.) and the GW impact.

Table 5
Shared analysis of the difference between external costs: gas engine (D1) versus conventional centralised (A)—Milan

	Net difference (EXTC D1-EXTC A) (best guess; 1% discount rate)	Share of the different effects				
		Lower GHG emissions of DG	Higher non-GHG emission rates of DG	Micro-localisation effect	Macro-localisation effect	Combined effects
Values[a] (k€)	+110.7	−312.8	+333.7	+9.6	+9.8	+70.3
Percentage (%)	100	−282.6	+301.4	+8.7	+8.9	+63.5

Note: EXTC D1: external cost of DG CHP gas engine in Milan; EXTC A: external costs of the conventional centralised supply.
[a]Excluding external costs of exploration, production and transportation fuel cycle stages.

6. Total cost/benefits

We have now reached the concluding point. By adding together internal and external costs, we can obtain the total costs of centralised and decentralised supplies and consequently the DG social benefits. For the sake of simplicity, we do not present the results in terms of cumulative probability distributions illustrated above and only report their best guess (Table 6).

Total costs fully confirm the unfavourable outcome for DG. Looking at the best guess values, DG total costs are lower than those of large power supply only in two cases (gas engine in Palermo and gas turbine in Milan, both in the case of the hospital), with 1% discount rate and compared to the conventional centralised system. However, even in these cases, cost saving does not exceed 1%.

Energy saving due to CHP and reduced transmission costs are therefore not sufficient to ensure DG social competitiveness. Large power generation is still preferable from this point of view. To be more specific, saving on fuel and electricity transport costs are counterbalanced by higher investment costs while the environmental benefits due to reduced GHG emissions are offset (on average) by the higher impact of the local–regional pollutants (mainly due to higher NO_x emissions).

This also helps us clarify why ‘‘isolated’’ solutions are better than ‘‘open’’ solutions[31] (recall the discussion in Section 3). The latter generate electricity exceeding customer need, with higher fuel consumption (compared to ‘‘isolated’’ solutions). Since DG environmental impact due to SO_x, PM_{10} and NO_x emissions of DG is higher than that of centralised supply, this causes an additional increase in local–regional impact (compared to ‘‘isolated’’ solutions).

Table 7 shows the results of the gas engine in Milan. As we can see, the internal costs of ‘‘open’’ solutions are similar (slightly better) to those of ‘‘isolated’’ one, but external costs are much higher.

Similar results can be obtained in the other cases. Therefore, ‘‘isolated’’ solutions always perform better than the ‘‘open’’ one. Furthermore, since ‘‘open’’ solutions involve electricity export to the grid, they also involve higher transaction costs.

Nevertheless, our analysis does not end here. We still have to verify the robustness of the final results by measuring their sensitivity to the variability of those parameters previously considered fixed. Furthermore, we have to account for the DG benefits due to increased power supply reliability and the uncertainty about the external costs of the local and regional pollutants. This sensitivity analysis will also help us find the overall range of social DG competitiveness.

7. Sensitivity analysis and overall range of DG social competitiveness

Sensitivity analysis is useful not only to verify the robustness of the previous results but also for two other important reasons. On the one hand, as mentioned above, it helps us understand how the variability of some crucial parameters affects DG benefits and as such allows us to identify the overall range of DG social competitiveness. On the other hand, it could be useful in pointing out how DG could improve in the near future. Furthermore, in this section we take into account the DG benefits due to increased power reliability (in terms of range of benefits) and the statistical uncertainty about the external costs of the local and regional pollutants.

The main factors affecting DG benefits can be grouped into four categories: structural conditions; highly volatile ‘‘over time’’ parameters; technological-related factors; network-related parameters.

Initially, for the sake of simplicity (and without loss of generality), we will restrict our investigation to the gas engine for the hospital in Palermo (D1) with 1% discount rate, which is the best DG application, compared to the heat pump (which is the best centralised option). Later, when we will attempt to estimate the overall range of DG social competitiveness, we will consider all DG solutions and applications.

[31]For a detailed analysis of the ‘‘open’’ solutions, see Gullí (2003).

Table 6
Social costs (SC = INTC + EXTC; best guess) and benefits (k€)

	Centralised systems		Decentralised systems					
	A, convent	B, Heat pump	D1, Gas engine	D1/A	D1/B	D2, Gas turbine	D2/A	D2/B
Residential building								
Milan								
Internal (INTC)	3302.9	2999.3	3550.3	1.07	1.18	3455.4	1.05	1.15
External (EXTC)								
($r = 1\%$)	1160.3	931.7	1240.0	1.07	1.33	1140.5	0.98	1.22
($r = 3\%$)	416.6	330.2	657.1	1.58	1.99	497.2	1.19	1.51
Total (SC)								
($r = 1\%$)	4463.2	3931.0	4790.3	1.07	1.22	4595.9	1.03	1.17
($r = 3\%$)	3719.5	3329.5	4207.4	1.13	1.26	3952.6	1.06	1.19
Palermo								
Internal (INTC)	2968.0	2765.6	3505.9	1.18	1.27	3459.7	1.17	1.25
External (EXTC)								
($r = 1\%$)	900.1	792.9	802.4	0.89	1.01	841.3	0.93	1.06
($r = 3\%$)	318.4	281.0	345.9	1.09	1.23	324.9	1.02	1.16
Total (SC)								
($r = 1\%$)	3868.1	3558.5	4308.3	1.11	1.21	4301.0	1.11	1.21
($r = 3\%$)	3286.4	3046.6	3851.8	1.17	1.26	3784.6	1.15	1.24
Hospital								
Milan								
Internal (INTC)	28098.9	26289.2	27350.9	0.97	1.04	27462.0	0.98	1.04
External (EXTC)								
($r = 1\%$)	11852.5	10154.2	13597.1	1.15	1.34	12182.3	1.03	1.20
($r = 3\%$)	4237.6	3596.1	7204.9	1.70	2.00	5454.6	1.29	1.52
Total (SC)								
($r = 1\%$)	39951.4	36443.4	40948.0	1.02	1.12	39644.3	0.99	1.09
($r = 3\%$)	32336.5	29885.3	34555.8	1.07	1.16	32916.6	1.02	1.10
Palermo								
Internal (INTC)	26330.8	24496.1	26891.4	1.02	1.10	27039.9	1.03	1.10
External (EXTC)								
($r = 1\%$)	9990.5	9104.8	9134.7	0.91	1.00	9469.1	0.95	1.04
($r = 3\%$)	3492.7	3211.1	3904.6	1.12	1.22	3656.6	1.05	1.14
Total (SC)								
($r = 1\%$)	36321.3	33600.9	36026.1	0.99	1.07	36509.0	1.01	1.09
($r = 3\%$)	29823.5	27707.2	30796.0	1.03	1.11	30696.5	1.03	1.11

Table 7
Social costs and benefits (k€): "open" solutions (best guess)

	Centralised systems		Centralised systems "open" solution		
	A, Convent	B, Heat pump	C1, Gas engine	C1/A	C1/B
Residential building, Milan					
Internal	3302.9	2999.3	3436.1	1.04	1.15
External					
($r = 1\%$)	1160.3	931.7	1938.7	1.67	2.08
($r = 3\%$)	416.6	330.2	1268.1	3.04	3.84
Total					
($r = 1\%$)	4463.2	3931.0	5374.8	1.20	1.37
($r = 3\%$)	3719.5	3329.5	4704.2	1.26	1.41

7.1. Structural conditions (climate and territorial factors)

The base case concerns two locations, Milan and Palermo, which represent two extreme situations in terms of environmental impact. Unfortunately, these two locations are complementary in terms of climate conditions. In Milan, where the environmental impact due to local–regional pollutants is higher, the climate is colder so that CHP is more profitable and DG internal costs are lower. In the case of Palermo, the situation is just the opposite. Since the situation is so complementary, it implies a sort of partial compensation between external and internal costs so that the two locations do not perfectly represent the two extreme situations of climate and geographic locations considered together. Therefore, in order to eliminate this effect, we can swap the climate situations of the two locations by simulating in Milan the climate conditions of Palermo (worst case) and in Palermo the climate conditions of Milan (best case). Switching from the base to the worst case implies a considerable decrease in DG benefits (the ratio of costs goes up to 1.17 from 1.07) whereas switching from the base to the best case implies only marginal improvements so that the ratio of costs is still higher than one (the ratio of costs goes down to 1.06).

Furthermore, while transmission costs can be considered almost independent on customer geographic location, distribution costs could substantially depend on territorial concentration of the customers. Intuitively, the lower (higher) customer territorial concentration, the higher (lower) the electricity distribution costs and, consequently, the higher (lower) the cost saving due to DG bypass. Nevertheless, this is only partially true for the following reason. Gas fired DG involves electricity for natural gas substitution and consequently expanding gas consumption (with the need of expanding gas supply capacity). Since even natural gas distribution costs depend on customer geographic location, in a similar way (i.e. the lower territorial customer concentration the higher gas distribution costs), using gas fired DG in low populated areas provides an additional advantage (on the electricity side) which could be partially counterbalanced by higher gas distribution costs (vice-versa, in the case of high populated areas). In order to evaluate the extent of this effect, we use the results of two econometric models on electricity and gas distribution costs in Italy.[32] These results highlight that, depending on territorial "customer density" (e.g. number of customers per km^2), electricity distribution costs in Italy range from −20% to +15% of the average (national value) and gas distribution costs range from −30% to +25%. By using lower and upper limits of these intervals in the estimating model of DG social costs and benefits, the ratio of costs ranges from 1.06 (low "customer density") to 1.09 (high "customer density"). Thus, "customer density" has only a marginal impact on (gas fired) DG social value.

7.2. Volatility

Although all the parameters affecting DG benefits may change over time, some may change more than others. Of these, natural gas price is certainly the most important. In order to take into account the impact of its volatility we refer to historical data and in particular to the range of the annual average price variability over the last 20 years. By using this range, the ratio of costs ranges from 1.04 (high natural gas price) to 1.11 (low natural gas price). Thus, DG benefits are medium–low sensitive to natural gas price variability.

7.3. Technological progress

Technological progress affects DG social cost–benefit mainly through the electrical efficiency and the investment costs of CHP small plants. In order to verify the impact of these factors, we can refer to plausible ranges of variability. Regarding investment costs, we suppose that DG investment cost per unit of power capacity will remarkably decrease in the future (50% of the current value). Regarding net plant efficiency, we use the maximum value which engineers predict for these technologies (and for the plant size considered in this analysis): 40% for the gas turbine and 47% for the gas engine. In the case of the gas engine, reduction in investment costs implies a ratio of costs equal to 1.01 and increasing in electrical efficiency implies a ratio of costs equal to 1.03. Thus, DG benefits are medium sensitive to investment costs and electrical efficiency, but again the ratio of costs is still higher than one.

7.4. Transport network congestion

Electricity and gas transport costs utilised in the base case are average values. Therefore, they do not take into account the possible effect of grid congestion. In order to give an idea even about the influence of transport costs, we attempt to simulate their impact. This simulation is quite simple for natural gas. Detailed data on gas transportation are in fact available for Italy. The fixed component of gas transport price ranges from a minimum of 1.85 to a maximum of 5.69 USD/m^3 per day (−42% to 79% compared to the average value used in the base case) depending on customer and gas field (or importing point) locations. Unfortunately, since such information is not available for electricity in Italy, we refer to the geographic value dispersion of the electricity system in England:[33] from 1.4 to 16.7 USD/kW (−84%

[32]See Gullí (2000) and AEEG (2000).

[33]See National Grid (2002).

to 90% of the base case value). The sensitivity analysis shows that DG benefits are medium–low sensitive to both natural gas and electricity transport costs. In the case of natural gas the ratio of costs ranges from 1.04 (low transport costs) to 1.11 (high transport costs), in the case of electricity from 1.06 (high transport costs) to 1.09 (low transport costs). Finally, concerning gas transport congestion, it is important to underline that DG could reduce gas demand and therefore could reduce congestion in peaking periods. Strachan (2000, 2003) deals with this issue estimating that DG reduces gas use for Florida by around 24% (with replacement of CCGT and heat boilers). However, we think that the above-proposed range of gas transport costs can include this DG advantage.

7.5. Power supply reliability

DG can avoid or reduce power outages associated with the grid that can cause operational downtime and health and safety concerns. We propose calculations based on the minutes lost per customer per year in Europe (from 200 to 700 min)[34] and on a value of loss load (VOLL) equal to 6000 €/MWh.[35] Given these values, DG advantage in terms of increased power reliability ranges from 0.2 to 0.8 c€/kWh (kWh of electricity consumption). These values are consistent with the estimations reported in the literature.[36] By using this range, the ratio of costs ranges from 1.01 (high benefits) to 1.06 (low benefits). Thus, DG social value is medium–high sensitive to benefits due to increased power supply reliability. Furthermore, it is important to underline that DG provides another important advantage when we consider the problem of the electricity system exposure to deliberate attacks. Zerriffi et al. (2002) demonstrate that the distributed system proves to be up to five times less sensitive to measures of systematic attack, compared to centralised system.

7.6. Overall range of DG social competitiveness

Sensitivity analysis clearly demonstrates that the results emerging from the base case are extremely robust. No parameter (considered separately) can invert the previous evaluation of DG competitiveness. Nevertheless, this is not enough since we still have to verify what can be obtained by combining parameter variability. In particular, we are interested in the case in which all variables are favourable (i.e. Milan climate in Palermo, high natural gas price, low DG investment costs, high DG plant efficiency, high electricity transport costs, low gas transport and low territorial "customer density", low power supply reliability) or unfavourable (i.e. Palermo climate in Milan, low natural gas price, no improvement in DG investment costs and electrical efficiency and so on) to DG deployment. These two extreme cases in fact identify by far the best and worst case of DG social competitiveness. Furthermore, this time, we also consider the uncertainty about the external costs of the local and regional pollutants. As pointed out above, ExternE, in this case, utilises multiplicative confidence intervals which are much easier to specify than an entire probability distributions. Thus, we internalise this uncertainty by means of the extreme values corresponding to 95% confidence interval. The worst case corresponds to the upper limit of the 95% confidence interval $\mu_g \cdot \sigma_g^2$. The best case corresponds to the lower limit of the 95% confidence interval μ_g/σ_g^2. We use the central value of the range reported in Table 3 ($\sigma_g = 4$) as estimate of geometric standard deviation. The geometric means μ_g approximately equals the median values.

The overall results are reported in Fig. 6 and presented in terms of cumulative distributions in order to internalise the uncertainty regarding the marginal cost of CO_2 emissions (whereas, concerning the uncertainty about the external costs of the local–regional pollutants, we uses the limits of the 95% confidence interval). The first observation concerns the curve shapes that are almost vertical thus reconfirming that uncertainty about GHG external cost has a very low impact on DG benefits. This allows us to clearly identify the social value of DG and to be certain of the effectiveness of the social cost–benefit analysis implemented here. In fact, Fig. 6 provides an indisputable picture since the range of positive values of DG benefits (ratio of costs lower than one) in the residential sector is very restricted compared to the range of negative values. The framework is slightly better in the case of the hospital, but again the range of negative value of DG benefits is quite larger than that of positive values.

8. Conclusions

This paper has attempted to measure the social value of DG in the residential and service sectors by comparing decentralised solutions to large power supply. The paper seems to support the hypothesis that centralised supply is still preferable to extensive decentralisation. Rather, there is evidence in favour of increasing centralisation through the deployment of the totally electric solution, the heat pump, which emerges as the best technology. Moreover, the overall range of DG social competitiveness is restricted, even

[34] These values refer to 1999–2001, see AEEG (2003).

[35] This value is consistent with the discounted VOLL adopted in the UK in 1991 in order to define the capacity payment in the electricity sector. Notice that some authors consider this value quite high, see Newbery (2001).

[36] Arthur D. Little (1998) propose a value around 0.6 cUSD/kWh (35 USD/kW-yr).

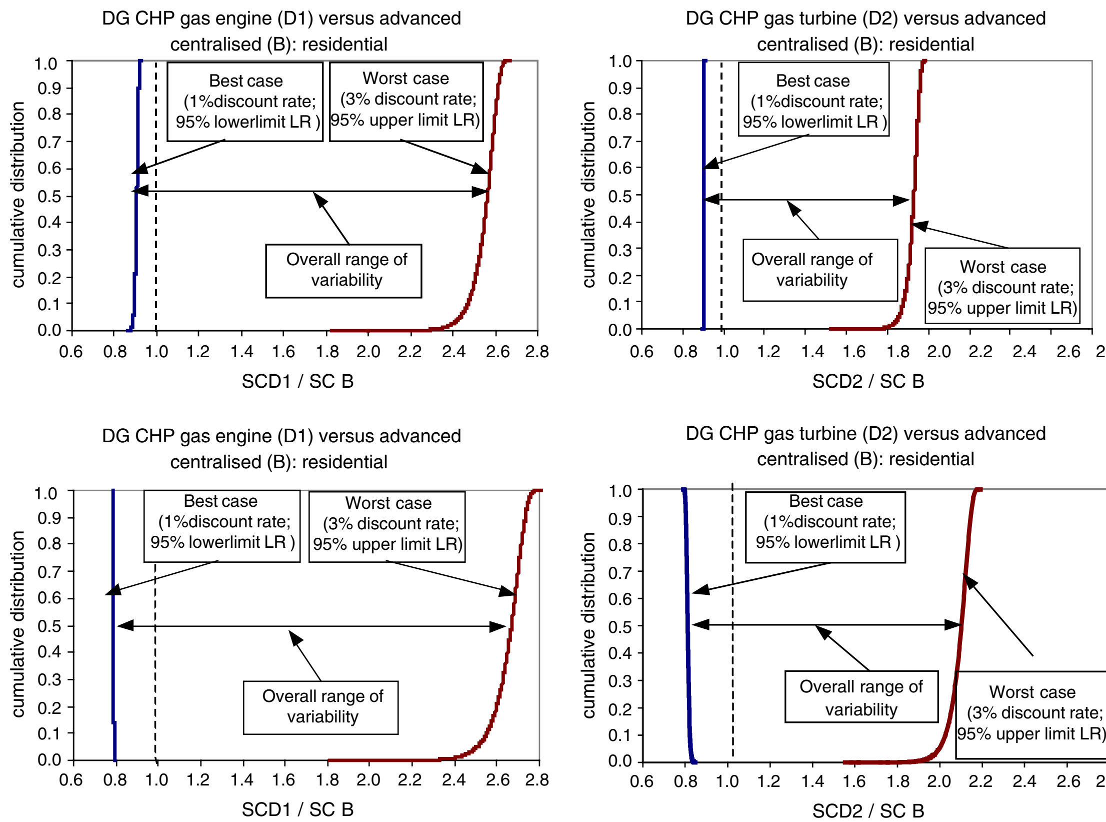

Fig. 6. Overall range of DG social competitiveness. *Note*: SC = social costs; D1 = gas engine; D2 = gas turbine in Milan; B = heat pump; LR = Local–regional pollutant impact.

considering remarkable improvements in DG electrical efficiency (gas turbine up to 40% and gas engine up to 47%) and investment costs (50% of the current value). The results are particularly unfavourable for the residential sector, whereas, in the service sector, the performance of DG technologies is slightly better.

Given this unfavourable framework, we have to ask ourselves why operators, regulators and legislators are so optimistic about small DG development in these sectors. Answering this question would require enlarging the perspective by analysing the influence of market distortions and supporting environmental policies.

Market distortions (market power in power markets, as well as inefficient price regulation and energy taxation) might play a fundamental role in raising DG profitability beyond its real social value. Emerging market power might lead to set prices above marginal costs and this strongly raises DG profitability. Inefficient price regulation (via distorted tariff structures) and energy taxation (via "non-pigouvian" taxes) could play a similar role, in this respect. For instance, electricity two-part tariffs with high weight of the variable component (beyond the optimal proportion), as well as (too) high excise taxes on end-use electricity, combined with (too) low taxes on natural gas, could strongly increase DG competitiveness. Further research works in this field might provide empirical evidence of these effects.

At the same time, too much emphasis on global environmental effects, and consequently on the extent of energy saving, might distort the perception of the real environmental value of DG.

In this respect, despite the uncertainty about the external cost estimations, we have found that the global benefits of DG (due to lower emissions of greenhouse gases-GHG) are counterbalanced by the higher impact of local–regional pollutants (mainly due to NO_x emissions).

This result has two interesting implications. First, on the policy implication side, it helps us to reflect upon the ambiguity of environmental policies which focus on the reduction of GHG emissions and disregard the possible trade-off between the impact of GW and the impact of the local–regional pollutants (unless one totally denies the rationality of making tradeoffs between intergenerational environmental impacts). Second, on the methodological side, it underlines the importance of the economic evaluations of the environmental externalities (which allows us to compare different kinds of environmental impacts).

Regarding this issue, we are aware that methodologies to evaluate external cost might be largely imperfect.[37] In our opinion, however, they can provide useful

[37]For a critical analysis of the methods of economic evaluations of the environmental externalities, see Stirling (1997).

Table A.1
Applications: capacity needs and energy consumption

		Residential building (volume: 57,600 cm)		Hospital (300 beds)	
		Milan	Palermo	Milan	Palermo
Structural electricity need					
Maximum capacity	(kW)	270	270	2000	2000
Annual consumption	(MWh/y)	788	788	13,140	13,140
Air conditioning need					
Cool maximum capacity	(kW)	1300	1420	9165	10,082
Annual consumption (summer)	(MWh/y)	2340	2574	17,082	18,790
Space heating need					
Maximum capacity	(kW)	1006	603	7090	3757
Annual consumption (winter)	(MWh/y)	1800	562	13,140	5256
Hot water for sanitary uses					
Capacity (assumed constant)	(kW)	55	55	500	500
Annual consumption	(MWh/y)	482	482	4380	4380

Source: Bruzzi (2002).

Table A.2
Power technologies: electrical efficiency and emissions rate

	Plant size (kWe)	Efficiency (%)	Emission rate[a]			
			CO_{2eq} (g/kWh)	SO_x (g/MWh)	NO_x (g/MWh)	PM_{10} (g/MWh)
Uncontrolled gas-fired lean burn gas engine	700	42	431.2	2.4	855.0	11.7
Uncontrolled small gas turbine	700	35	523.7	2.1	402.3	27.8
CCGT (SCR)[b]	400,000	54	332.7	1.7	25.8	17.2

Source: Regulatory Assistance Project (2001).
[a]Per unit of electricity generated.
[b]SCR: selective catalytic reduction.

indications when used to compare two technological alternatives and when the uncertainty about their estimations can be internalised in the evaluation model (like we have attempted to do in this paper).

Resuming, one needs to be prudent in supporting deep energy supply decentralisation (in particular, up to residential sector). Small distributed plants might be useful in mitigating market power and increasing system reliability (this last advantage is important not only when we consider the normal power outages but also when we account for the risk of deliberate attacks). In several important market segments (i.e. industrial applications), they could really be competitive and in some circumstances (i.e. renewable energy sources), they really improve environmental conditions. Nevertheless, we should realise that, from the social welfare point of view, small DG social benefits are at least uncertain, in the residential and service sectors. Removing technical and economic barriers is welcomed but providing generalised subsides must be carefully evaluated.

Finally, we must not conclude our treatment without pointing out two phenomena which could substantially change this framework.

First, constraints (due to problems of public local acceptability) on large power generation and electricity transport development could strongly push DG deployment. In this case, DG would be, in fact, the only available solution to meet the increase in electricity demand. However, this also would point out how public risk perception could lead to a sub-optimal social-welfare equilibrium.

Second, radical technological change can increase DG performance. We obviously refer to the development of the fuel cells which could reach 70–80% electrical efficiency, with a very low environmental impact (both global and local–regional). Unfortunately, fuel cell investment costs are still too high (1500–2000 USD/kW), so that the economic viability is far to be achieved. In this respect, evaluating social benefits of fuel cell development is certainly another issue which needs to receive attention in future research works in the field of DG economics and policy.

Acknowledgements

An earlier version of this paper was presented at the "Regulation Seminars" of the Department of Applied Economics (DAE) of University of Cambridge. The author likes to thank the seminar participants at DAE for their constructive comments. All errors pertain to the author.

Appendix A

This Appendix includes all technical and economic data used in this paper. Tables A.1–A.4 show the technical data of applications and technologies. Tables A.5–A.8 describe the method to calculate energy primary consumption. Finally, Table A.9 includes the values of the parameters and variables of the model used

Table A.3
Applications: plant sizes

	A	B	C1	C2	D1	D2
Residential building in Milan						
Plant typology	CB + CR	HP	CHP + AR		CHP + HP + AR	
Power generation (CHP)			1200	1035	661	619
Absorbing refrigerator (cool cap.)			1300	1300	694	760
Compressing refrigerator (cool cap.)	1300	1328			782	730
Conv. boiler—space heating (fuel cap.)	1117					
Convent. boiler—hot water (fuel cap.)	61					
Condens. boiler—hot water (fuel cap.)		50				
Hospital in Milan						
Power generation (CHP)			8547	7364	4753	4439
Absorbing refrigerator (cool cap.)			9165	9165	4897	5384
Compressing refrigerator (cool cap.)	9165	10,100			5571	5193
Conv. boiler—space heating (fuel cap.)	7878					
Convent. boiler—hot water (fuel cap.)	556					
Condens. boiler—hot water (fuel cap.)		459				
Residential building in Palermo						
Plant typology	CB + CR	HP	CHP + AR		CHP + HP + AR	
Power generation (CHP)			1315	1136	710	664
Absorbing refrigerator (cool cap.)			1430	1430	887	819
Compressing refrigerator (cool cap.)	1430	1430			854	802
Conv. boiler—space heating (fuel cap.)	670					
Convent. boiler—hot water (fuel cap.)	71					
Condens. boiler—hot water (fuel cap.)		50				
Hospital in Palermo						
Power generation (CHP)						
Absorbing refrigerator (cool cap.)			9361	8072	5096	4764
Compressing refrigerator (cool cap.)			10,082	10,082	5283	5797
Conv. boiler—space heating (fuel cap.)	10,082	10,082				
Convent. boiler—hot water (fuel cap.)	4174					
Condens. boiler—hot water (fuel cap.)	556	459				

CB: conventional boiler; CR: compressing refrigerator; HP: electrical heat pump; AR: absorbing refrigerator; CHP: combined heat and power plant, TG: large turbine gas (for centralized peak generation).
Source: Bruzzi (2002).

Table A.4
Investment costs[a] turn-key (€/kW)

	Residential				Hospital			
	A	B	D1	D2	A	B	D1	D2
CB	26				16			
CR	316				260			
HP		418	418	418		361	361	361
AR			226	226			155	155
CHP			900	1010			790	900
TG				350				

[a]Per unit of output; *Note*: TG: large turbine gas (for centralised peak generation).

Table A.5
Energy flows and assessment of energy primary consumption: residential building (Milan)

S: summer; W: winter		A		B		C1		C2		D1		D2	
MWh		S	W	S	W	S	W	S	W	S	W	S	W
Structural electr. need	EE_s	394	394	394	394	394	394	394	394	394	394	394	394
Heat space heat./con.	TE_h	232	1800	232	1800	232	1800	232	1800	232	1800	232	1800
Heat for hot water	TE_w	241	241	241	241	241	241	241	241	241	241	241	241
Cold for space condit.	CE	2316	0	2316	0	2316	0	2316	0	2316	0	2316	0
RatioTE_{chp}/EE_{chp}	η_t					1.14	1.14	1.57	1.57	1.14	1.14	1.57	1.57
RatioCE_{ar}/TE_{chp}	η_{ar}					0.9		0.75		0.9		0.75	
RatioTE_{hp}/EE_{hp}	COP				3.3						3.3		3.3
RatioCE_{cr}/EE_{cr}	η_{cr}	3.7		3.7						3.7		3.7	
CB thermal effic.	η_{cb}	90%	90%	109%	109%								
CHP total effic.	η_{chp}					90%	90%	90%	90%	90%	90%	90%	90%
Central electr. Eff.	η_e	0.48	0.48	0.48	0.48	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
TE from CB	TE_{cb}	241	2041	241	241								
CE from AR	CE_{ar}					2316		2316		651		775	
CE from CR	CE_{cr}	2316		2316						1665		1541	
TE low from HP	TE_{hp}	232		232	1800	232		232		232	1182	232	963
EE for CR	$EE_{cr} = CE_{cr}/\eta_{cr}$	626		626						450		417	
EE for HP	$EE_{hp} = TE_{hp}/COP$				545						358		292
TE from CHP	$TE_{chp} = CE_{ar}/\eta_{ar} + TE_w$					2814		3329		965		1274	
TE from CHP	TE_{chp}						2041		2041		859		1078
EE from CHP	$EE_{chp} = TE_{chp}/\eta_t$					2463	1786	2118	1299	844	752	811	686
PE for CB	$PE_{cb} = TE_{cb}/\eta_{cb}$	268	2268	221	221								
PE for CHP	$PE_{chp} = (TE_{chp} + EE_{chp})/\eta_{chp}$					5863	4252	6053	3711	2009	1791	2316	1960
Imported *EE*	$EE_{imp} = EE_s + EE_{cr} + EE_{hp} - EE_{chp}$	1020	394	1020	939	−2069	−1392	−1724	−905	0	0	0	0
Total primary energy	$PE = PE_{cb} + PE_{chp} + EE_{imp}/\eta_e$	2393	3089	2346	2178	1885	1575	2736	1971	2009	1791	2316	1960
Primary energy	$PE_a = PE_s + PE_w$	5481		4524		3461		4707		3800		4276	

A: centralized conventional system; AR: absorbing refrigerator; B: advanced centralised system (HP); C1: "open" gas engine; C2: "open" gas turbine; CB: condensing boiler; CHP: combined heat and power generation; CR: compressing refrigerator; D1: "isolated" gas engine; D2: "isolated" gas turbine; *EE*: electrical energy (power); HP: heat pump; *PE*: primary energy (fuel); and *TE*: thermal energy.

Table A.6
Energy flows and assessment of energy primary consumption: residential building (Palermo)

S: summer; W: winter		A		B		C1		C2		D1		D2	
MWh		S	W	S	W	S	W	S	W	S	W	S	W
Structural electr. need	EE_s	394	394	394	394	394	394	394	394	394	394	394	394
Heat space heat./con.	TE_h	258	561	258	561	258	561	258	561	258	561	258	561
Heat for hot water	TE_w	241	241	241	241	241	241	241	241	241	241	241	241
Cold for space condit.	CE	2575	0	2575	0	2575	0	2575	0	2575	0	2575	0
RatioTE_{chp}/EE_{chp}	η_t					1.14	1.14	1.57	1.57	1.14	1.14	1.57	1.57
RatioCE_{ar}/TE_{chp}	η_{ar}					0.9		0.75		0.9		0.75	
RatioTE_{hp}/EE_{hp}	COP				5.3						5.3		5.3
RatioCE_{cr}/EE_{cr}	η_{cr}	3.4		3.4						3.4		3.4	
CB thermal effic.	η_{cb}	90%	90%	109%	109%								
CHP total effic.	η_{chp}					90%	90%	90%	90%	90%	90%	90%	90%
Central electr. eff.	η_e	0.48	0.48	0.48	0.48	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
TE from CB	TE_{cb}	241	802	241	241								
CE from AR	CE_{ar}					2575		2575		743		873	
CE from CR	CE_{cr}	2575		2575						1832		1702	
TE low from HP	TE_{hp}	258		258	561	258		258		258	289	258	141
EE for CR	$EE_{cr} = CE_{cr}/\eta_{cr}$	757		757						539		500	
EE for HP	$EE_{hp} = TE_{hp}/COP$				106						55		27
TE from CHP	$TE_{chp} = CE_{ar}/\eta_{ar} + TE_w$					3102		3674		1066		1406	
TE from CHP	TE_{chp}						802		802		513		661
EE from CHP	$EE_{chp} = TE_{chp}/\eta_t$					2714	702	2338	510	933	449	894	421
PE for CB	$PE_{cb} = TE_{cb}/\eta_{cb}$	268	891	221	221								
PE for CHP	$PE_{chp} = (TE_{chp} + EE_{chp})/\eta_{chp}$					6463	1671	6681	1458	2221	1068	2556	1202
Imported *EE*	$EE_{imp} = EE_s + EE_{cr} + EE_{hp} - EE_{chp}$	1151	394	1151	500	−2320	−308	−1944	−116	0	0	0	0
Total primary energy	$PE = PE_{cb} + PE_{chp} + EE_{imp}/\eta_e$	2666	1712	2620	1262	2001	1079	2942	1234	2221	1068	2556	1202
Primary energy (year)	$PE_a = PE_s + PE_w$	4378		3882		3080		4176		3289		3757	

A: centralized conventional system; AR: absorbing refrigerator; B: advanced centralized system (HP); C1: "open" gas engine; C2: "open" gas turbine; CB: condensing boiler; CHP: combined heat and power generation; CR: compressing refrigerator; D1: "isolated" gas engine; D2: "isolated" gas turbine; *EE*: electrical energy (power); HP: heat pump; *PE*: primary energy (fuel); and *TE*: thermal energy.

Table A.7
Energy flows and assessment of energy primary consumption: hospital (Milan)

S: summer; W: winter		A		B		C1		C2		D1		D2	
MWh		S	W	S	W	S	W	S	W	S	W	S	W
Structural electricity need	EE_s	6570	6570	6570	6570	6570	6570	6570	6570	6570	6570	6570	6570
Heat space heat./con.	TE_h	1708	13140	1708	13140	1708	13140	1708	13140	1708	13140	1708	13140
Heat for hot water	TE_w	2190	2190	2190	2190	2190	2190	2190	2190	2190	2190	2190	2190
Cold for space condit.	CE	17082	0	17082	0	17082	0	17082	0	17082	0	17082	0
RatioTE_{chp}/EE_{chp}	η_t					1.14	1.14	1.57	1.57	1.14	1.14	1.57	1.57
RatioCE_{ar}/TE_{chp}	η_{ar}					0.9		0.75		0.9		0.75	
RatioTE_{hp}/EE_{hp}	COP				3.3						3.3		3.3
RatioCE_{cr}/EE_{cr}	η_{cr}	3.7		3.7						3.7		3.7	
CB thermal effic.	η_{cb}	90%	90%	109%	109%								
CHP total effic.	η_{chp}					90%	90%	90%	90%	90%	90%	90%	90%
Central electr. eff.	η_e	0.48	0.48	0.48	0.48	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
TE from CB	TE_{cb}	2190	15330	2190	2190								
CE from AR	CE_{ar}					17082		17082		7461		8754	
CE from CR	CE_{cr}	17082		17082						9621		8328	
TE low from HP	TE_{hp}	1708		1708	13140	1708		1708		1708	5809	1708	3391
EE for CR	$EE_{cr} = CE_{cr}/\eta_{cr}$	4617		4617						2600		2251	
EE for HP	$EE_{hp} = TE_{hp}/COP$				3982						1760		1028
TE from CHP	$TE_{chp} = CE_{ar}/\eta_{ar} + TE_w$					21170		24966		10480		13861	
TE from CHP	TE_{chp}						15330		15330		9521		11939
EE from CHP	$EE_{chp} = TE_{chp}/\eta_t$					18524	13414	15887	9755	9170	8330	8821	7598
PE for CB	$PE_{cb} = TE_{cb}/\eta_{cb}$	2433	17033	2009	2009								
PE for CHP	$PE_{chp} = (TE_{chp} + EE_{chp})/\eta_{chp}$					44104	31938	45393	27873	21834	19834	25203	21707
Imported *EE*	$EE_{imp} = EE_s + EE_{cr} + EE_{hp} - EE_{chp}$	11187	6570	11187	10552	−11954	−6844	−9317	−3185	0	0	0	0
Total primary energy	$PE = PE_{cb} + PE_{chp} + EE_{imp}/\eta_e$	25739	30721	25315	23992	21116	18776	27475	21747	21834	19834	25203	21707
Primary energy	$PE_a = PE_s + PE_w$	56460		49307		39893		49221		41668		46910	

A: centralized conventional system; AR: absorbing refrigerator; B: advanced centralized system (HP); C1: "open" gas engine; C2: "open" gas turbine; CB: condensing boiler; CHP: combined heat and power generation; CR: compressing refrigerator; D1: "isolated" gas engine; D2: "isolated" gas turbine; *EE*: electrical energy (power); HP: heat pump; *PE*: primary energy (fuel); and *TE*: thermal energy.

Table A.8
Energy flows and assessment of energy primary consumption: hospital (Palermo)

S: summer; W: winter		A		B		C1		C2		D1		D2	
MWh		S	W	S	W	S	W	S	W	S	W	S	W
Structural electr. need	EE_s	6570	6570	6570	6570	6570	6570	6570	6570	6570	6570	6570	6570
Heat space heat./con.	TE_h	1879	5256	1879	5256	1879	5256	1879	5256	1879	5256	1879	5256
Heat for hot water	TE_w	2190	2190	2190	2190	2190	2190	2190	2190	2190	2190	2190	2190
Cold for space condit.	CE	18790	0	17082	0	17082	0	17082	0	17082	0	17082	0
RatioTE_{chp}/EE_{chp}	η_t					1.14	1.14	1.57	1.57	1.14	1.14	1.57	1.57
RatioCE_{ar}/TE_{chp}	η_{ar}					0.9		0.75		0.9		0.75	
RatioTE_{hp}/EE_{hp}	COP				3.3						3.3		3.3
RatioCE_{cr}/EE_{cr}	η_{cr}	3.7		3.7						3.7		3.7	
CB thermal effic.	η_{cb}	90%	90%	109%	109%								
CHP total effic.	η_{chp}					90%	90%	90%	90%	90%	90%	90%	90%
Central electr. eff.	η_e	0.48	0.48	0.48	0.48	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
TE from CB	TE_{cb}	2190	7446	2190	2190								
CE from AR	CE_{ar}					17082		17082		7461		8754	
CE from CR	CE_{cr}	18790		17082						9621		8328	
TE low from HP	TE_{hp}	1879		1879	5256	1879		1879		1879	−46	1879	−1950
EE for CR	$EE_{cr} = CE_{cr}/\eta_{cr}$	5078		4617						2600		2251	
EE for HP	$EE_{hp} = TE_{hp}/COP$				1593						−14		−591
TE from CHP	$TE_{chp} = CE_{ar}/\eta_{ar} + TE_w$					21170		24966		10480		13861	
TE from CHP	TE_{chp}						7446		7446		7492		9396
EE from CHP	$EE_{chp} = TE_{chp}/\eta_t$					18524	6515	15887	4738	9170	6556	8821	5979
PE for CB	$PE_{cb} = TE_{cb}/\eta_{cb}$	2433	8273	2009	2009								
PE for CHP	$PE_{chp} = (TE_{chp} + EE_{chp})/\eta_{chp}$					44104	15513	45393	13538	21834	15609	25203	17083
Imported EE	$EE_{imp} = EE_s + EE_{cr} + EE_{hp} - EE_{chp}$	11648	6570	11187	8163	−11954	55	−9317	1832	0	0	0	0
Total primary energy	$PE = PE_{cb} + PE_{chp} + EE_{imp}/\eta_e$	26701	21961	25315	19015	21116	15618	27475	17061	21834	15609	25203	17083
Primary energy (year)	$PE_a = PE_s + PE_w$	48662		44330		36734		44535		37443		42286	

A: centralized conventional system; AR: absorbing refrigerator; B: advanced centralized system (HP); C1: "open" gas engine; C2: "open" gas turbine; CB: condensing boiler; CHP: combined heat and power generation; CR: compressing refrigerator; D1: "isolated" gas engine; D2: "isolated" gas turbine; EE: electrical energy (power); HP: heat pump; PE: primary energy (fuel); and TE: thermal energy.

Table A.9
Parameter values of the model

		Residential								Hospital							
		Centralised systems (centr)				Decentralised systems (DG)				Centralised systems (centr)				Decentralised systems (DG)			
		A		B		D1		D2		A		B		D1		D2	
		Milan	Palermo	Milan	Palermo	Milan	Palermo	Milan	Palermo	Milan	Palermo	Milan	Palermo	Milan	Palermo	Milan	Palermo
Investment costs (turn-key)	IC (k€)	441	470	557	599	1171	1296	1191	1286	2610	3368	3724	3717	7202	7773	7349	7934
O&M costs	OM (k€/y)	13.2	14.1	16.7	18.0	51.3	44.4	38.5	33.2	78.3	101.0	111.7	111.5	375.0	337.0	316.6	285.4
Natural gas																	
Consumption	$\tilde{E}^g$ (10^3 m^3)	264	120	46	46	406	352	459	404	2029	1116	419	419	4344	3903	4890	4408
Consumption	$\tilde{E}^g$ (MWh)	2529	1155	440	440	3890	3376	4399	3875	19466	10706	4018	4018	41668	37433	46910	42286
Equivalent number of full consumption hours	$\tilde{H}^g$ (h)	2148	1581	8760	8760	2355	1903	2844	2335	2308	2263	8760	8760	3508	2939	4228	3551
Maximum capacity need of the customer	$\tilde{P}^g$(m^3/d)	2945	1828	125	125	4133	4439	3870	4152	21100	11834	1148	1148	29718	31863	27755	29787
Natural gas price	μ^{gp} (m€/m^3)	138.8								138.8							
Incidence of working gas	β	0.069								0.069							
Storage and modulation variable cost	μ^{gsm}(m€/m^3)	15.5								15.5							
Storage and modulation fixed cost	f_1^{gsm} (m€/m^3/d)	4340.2								4340.2							
Transport variable cost	μ^{gT}(m€/m^3)	6.1								6.1							
Transport fixed cost	f_1^{gT} (m€/m^3/d)	3584.2								3584.2							
Distribution variable cost	μ^{gD} (m€/m^3)	0.0								0.0							
Distribution fixed cost	f_1^{gD} (m€/m^3/d)	6404.1								6404.1							
Supply variable cost	μ^{gsp}(m€/kWh)	0.0								0.0							
Supply fixed cost	f_1^{gsp} (m€/m^3/d)	2087.6	3363.2	25635.4	25365.4	1787.5	1736.3	1838.1	2524.6	291.4	519.6	3721.4	3721.4	1147.2	1140.2	1265.3	1250.2
Electricity																	
Consumption	$\tilde{E}^e$ (MWh)	1417	1542	1945	1648	0.0	0.0	0.0	0.0	17757	18218	21739	19349	0.0	0.0	0.0	0.0
Maximum capacity need of the customer	$\tilde{P}^e$ (kW)	840	1031	858	1031	—	—	—	—	5550	6847	6116	6847	—	—	—	—
Power plant size	P_e^* (kW)	—	—	—	—	661	710	619	664	—	—	—	—	4753	5096	4439	4764
Equivalent number of full consumption hours	$\tilde{H}^e$ (h)	1687	1496	2267	1599	—	—	—	—	3199	2661	3554	2826	—	—	—	—
Power generation variable cost	μ^{eG}(m€/kWh)[a]	38.2				—	—	—	—	38.2				—	—	—	—
Power generation fixed cost	f_1^{eG} (€/kW)	33.9				—	—	—	—	33.9				—	—	—	—
Transport variable cost	μ^{eT} (m€/kWh)	1.1				—	—	—	—	1.1				—	—	—	—
Transport fixed cost	f_1^{eT} (m€/kW)	9554.4				—	—	—	—	9554.4				—	—	—	—
Distribution variable cost	μ^{eD} (m€/kWh)	5.6				—	—	—	—	5.6				—	—	—	—
Medium voltage fixed distribution cost	$f_1^{eD_{MV}}$ (m€/kW)	21229.0				—	—	—	—	21229.0				—	—	—	—
Low voltage fixed distribution cost	$f_1^{eD_{LV}}$ (m€/kW)	14925.6				—	—	—	—	14925.6				—	—	—	—
Supply variable cost	μ^{esp}(m€/kWh)	0.0				—	—	—	—	0.0				—	—	—	—
Supply fixed cost	f_1^{esp} (m€/kW)	8240	6713	8153	6713	—	—	—	—	1247	1011	1132	1011	—	—	—	—
Cost of grid interconnection	δ^e (€/kW)	—	—	—	—	—	—	—	—	141.1							
Discount rate	(r)[b]	0.04								0.04							

[a]Including variable costs of SCR (selective catalytic reduction).
[b]For the internal costs.

to calculate internal costs. All economic values refer to 01/01/2002.

References

Ackermann, T., Andersson, G., Soder, L., 2001. Distributed generation: a definition. Electric Power System Research 57 (3), 195–204.

Arthur, D. Little, Inc., 1998. Distributed generation: understanding the economics. Arthur D. Little White Paper, Massachusetts.

Arthur, D. Little, Inc., 1999. Distributed generation: system interfaces. Arthur D. Little White Paper, Massachusetts.

AEEG—Autorità per l'Energia Elettrica e il Gas, 1999. Regolazione della tariffa base, dei parametri e degli altri elementi di riferimento per la determinazione delle tariffe di distribuzione e di vendita dell'energia elettrica ai clienti del mercato vincolato. Delibera n. 204/99, Milano.

AEEG—Autorità per l'Energia Elettrica e il Gas, 2000. Definizione dei criteri per la determinazione delle tarriffe per le attività di distribuzione del Gas e Fornitura ai Clienti del Mercato Vincolato. Delibera n. 237/00, Milano.

AEEG—Autorità per l'Energia Elettrica e il Gas, 2001. Testo integrato delle disposizioni dell'autorità per l'energia elettrica e il gas per l'erogazione dei Servizi di Trasporto, di Misura e di Vendita dell'Energia Elettrica. Delibera n. 228/01, Milano.

AEEG—Autorità per l'Energia Elettrica e il Gas, 2002. Disposizioni in materia di tariffe per il trasporto e il dispacciamento del gas naturale. Delibera n. 146/02, Milano.

AEEG—Autorità per l'Energia Elettrica e il Gas, 2003. Second benchmarking report on quality of electricity supply, September, Milan.

Boiteux, M., 1956. Sur la gestion des monopoles publics astreints à L'equilibre budgetaire. Econometrica 24, 22–40.

Bruzzi, V., 2002. Cogenerazione Distribuita, Pompe di Calore Reversibili e Frigoriferi ad Assorbimento nelle Utenze Civili. Quaderni di Ricerca Iefe. Univesità Bocconi, Milano, Gennaio.

Crew, M.A., Kleindorfer, P.R., 1986. The Economics of Public Utility Regulation. Macmillan, Basingstoke.

Electricité de France-Service des Etudes Economiques Générales, 1979. Le Calcul Economique et le Système Electrique. Eyrolles, Paris.

European Commission, 1997. ExternE: ExternE Project. Publishable Report, External Costs of Transport in ExternE. http://externe.jrc.es/reports.html.

European Commission, 1999a. ExternE: externalities of fuel cycles. ExternE Project, Methodology Updated 1998 Report, Office for Official Publications of the European Communities, Luxembourg.

European Commission, 1999b. ExternE: externalities of energy. Final Report, Global Warming, Office for Official Publications of the European Communities, Luxembourg.

European Commission, 1999c. ExternE: externalities of energy. ExternE Project, National Implementation, Office for Official Publications of the European Communities, Luxembourg.

European Commission, 1999d. ExternE: externalities of energy. Fuel Cycles for Emerging and End-Use Technologies, Transport and Waste, Office for Official Publications of the European Communities, Luxembourg.

European Commission, 1999e. ExternE: externalities of energy. ExternE Project, Common Annexes of the externE National Implementation Reports, http://externe.jrc.es/reports.html.

Frigerio, M., Gullí, F., Lorenzoni, A., 1995. External costs of fuel cycles. Final Report, ITGCC Fuel Cycle, Report Commissioned by the EC, ExternE Project.

Gullí, F., 2000. Economie di Scala versus Economie di densità nella distribuzione elettrica: un'analisi quantitativa. Economia delle Fonti di Energia e dell'Ambiente XLIII (2), 51–75.

Gullí, F., 2003. Distributed generation versus centralized supply: a social cost–benefit analysis. CMI (Cambridge-Massachusetts Institute of Technology) Working Papers, p. 30.

Jones, L.P., Tandon, P., Volgesang, I., 1990. Selling Public Enterprises. MIT Press, Cambridge. MA.

Krewitt, W., 2002. External costs of energy—do the answers match the questions? Looking back at 10 years of ExternE. Energy Policy 30 (8), 839–848.

Madlener, R., Schmid, C., 2003. Adoption and diffusion of decentralised energy conversion technologies: the success of engine co-generation in Germany. Energy and Environment 14 (5), 627–662.

McDonald, C.F., 2003. Recuperator considerations for future higher efficiency microturbines. Applied Thermal Engineering 20 (5), 1463–1487.

National Grid, 2002. The statement of use of system charges. Coventry: Issue 2.

Newbery, D.M., 2001. Privatization, Restructuring, and Regulation of Network Utilities. MIT Press, Cambridge MA.

Pfeifenberger, J.P., Hanser, P.Q., Ammann, P., 1997. What's the cards for distributed resources? The Energy Journal DR Special Issue, 1–16.

Pressman, I., 1970. A mathematical formulation of the peak-load pricing problem. Bell Journal of Economics 1 (2), 304–326.

Rabl, A., Spadaro, J.V., 1999. Damages and costs of air pollution: an analysis of uncertainties. Environment International 25, 29–46.

Regulatory Assistance Project, 2001. Model regulations for the output of specified air emissions from smaller-scale electric generation resources. RAP Report. Maine, November.

Resource and Dynamic Corporation, 1999. Industrial application for micropower: a market assessment. Report prepared for the US DOE. Washington, DC.

Schmaleense, R., 1993. Symposium on global climate change. Journal of Economic Perspectives 7 (4), 3–10.

Steiner, P.O., 1957. Peak load and efficient pricing. Quarterly Journal of Economics 71, 572–587.

Stirling, A., 1997. Limits to the value of external costs. Energy Policy 25 (5), 517–540.

Strachan, N., 2000. Adoption and supply of a distributed generation technology. Ph.D. Thesis, Carnegie Mellon University, Pittsburgh, PA.

Strachan, N., 2003. Distributed generation and path dependency. CEIC Working Paper, Carnegie Mellon University, January.

Strachan, N., Dowlatabadi, H., 2002. Distributed generation and distribution utilities. Energy Policy 30 (8), 649–661.

Valette, P., 1995. The European commission Externe project. Revue de l'Energie 467, 245–265.

Zerriffi, H., Dowlatabadi, H., Strachan, N., 2002. Electricity and conflict: advantages of a distributed system. The Electricity Journal, January/February, 55–65.