Distributed Generation versus Centralised Supply: a Social Cost-Benefit Analysis

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ABSTRACT

This paper attempts to verify whether we are moving towards a new paradigm of the network energy industry (electricity and natural gas), based on a wide decentralisation of the energy supply. We do this by comparing the social benefits of decentralised and centralised models, simulating "ideal" situations in which any source of allocative inefficiencies is eliminated. This comparison focuses on assessing internal and external benefits. The internal benefits are calculated by simulating the optimal prices of the electricity and gas inputs. The external benefits are estimated by applying the "ExternE" methodology, one of the most recent and accurate approaches in this field. The paper rejects the hypothesis that we are moving towards a new paradigm and points out how the considerable interest in the deployment of distributed generation (DG) is probably due to market distortions, in some cases, enforced by market reforms. In this respect, the paper reflects upon the real effectiveness of such reforms as well as the overall efficiency of the environmental policies focusing on the reduction of green-house gas emissions.

JEL classification: L51, L94, L95, O34, Q20, Q30.

Keywords: Distributed Generation, Social Cost-Benefit Analysis, Energy Economics, Environmental Economics, Technological Change.

Distributed Generation versus Centralised Supply: a Social Cost-Benefit Analysis

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1. Introduction

■ The 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 integrated firms.

Nevertheless, the impact of the market reforms in terms of social welfare is not clear yet. Although several analysis have been proposed in this field, the results do not converge. In the meanwhile, some recent dramatic events (i.e. the California energy crisis and the collapse of Enron) 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.

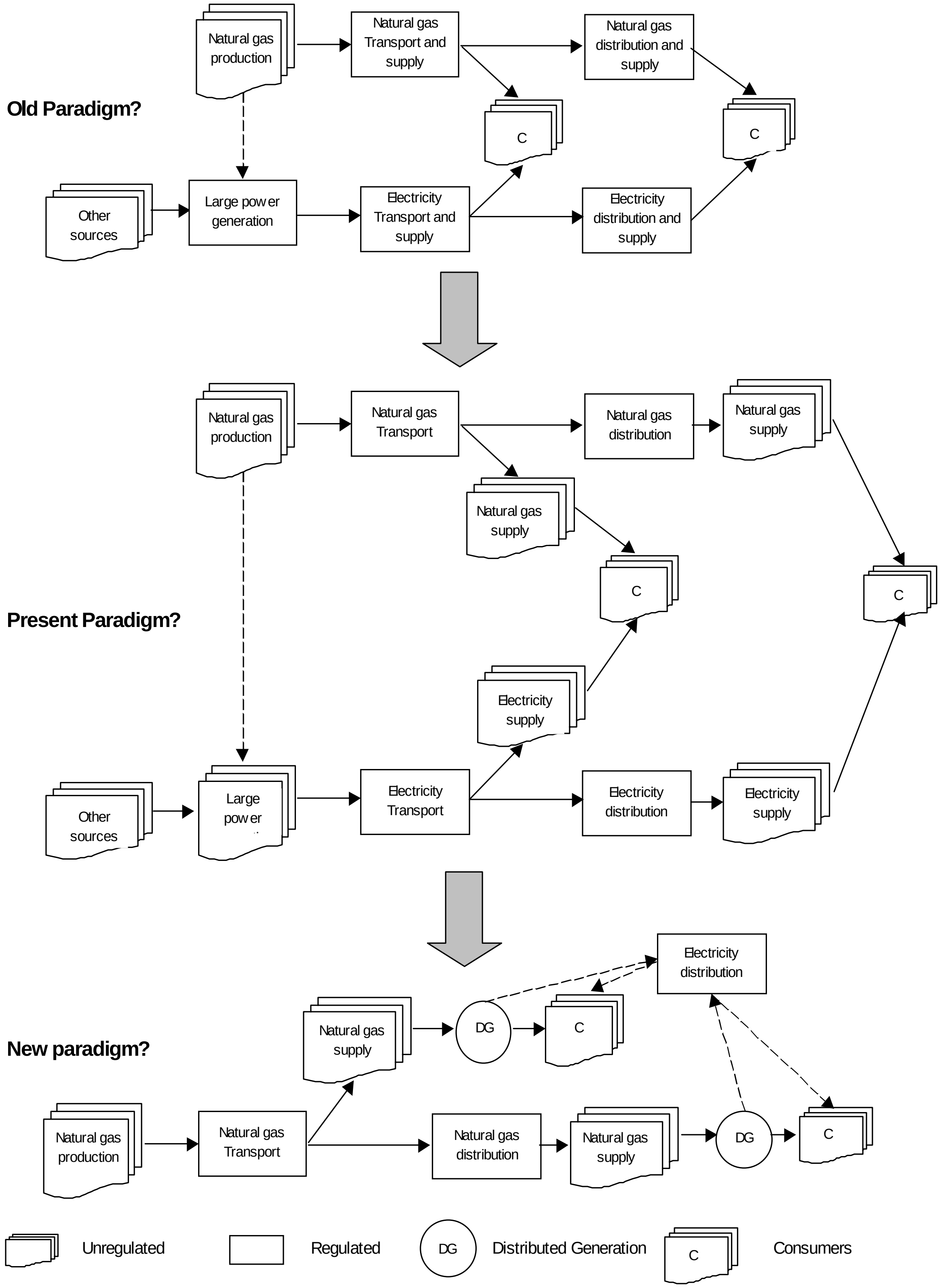
However, while this issue is still being debated, technological change and innovation offer us the prospect of revolutionary new scenarios. In particular, the performance of the small power technologies (the reciprocating engine, gas turbine, and fuel cells) has improved remarkably over the last decade. 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 (figure 1).

Distributed generation can provide several benefits which can be divided into two categories. The first includes the so-called 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[1]; etc.. The second category includes the so-called market-related benefits whose extent depends on how markets are organised: decreased exposure to electricity price volatility; improved power quality; increased power reliability; etc..

• francesco.gulli@uni-bocconi.it. This paper is the outcome of my research-work at the Department of Applied Economics (DAE) of the University of Cambridge. I would like to thank David Newbery, Luigi De Paoli, Gert Brunekreeft, Vittorio Bruzzi, Micheal Grubb, Karsten Neuhoff and the seminar participants at DAE and Iefe for their constructive comments.

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

Figure 1 – Industry models



In addition to these advantages, distributed generation can be attractive for another reason. Several authors think that its deployment could promote a technological change similar to what occurred in the telecommunication sector.

In fact, it allows customers and producers to bypass the local supply network, like mobile and satellite technologies, whose development has had a radical (positive) impact on the organisation and structure of the telecommunications industry. This similarity is probable exaggerated but it would be foolish to ignore its effect on raising policymakers' and operators' interest in DG social benefits and economic viability.

However, the realisation that DG could provide some benefits is only the starting point of our analysis. In order to verify whether we are moving towards a new paradigm, we first have to measure the extent of these benefits. This requires comparing centralised and decentralised supplies in terms of social welfare in order to identify the overall range of DG social competitiveness.

The article is organised in the following way. Section 2 illustrates the general approach and main assumptions of the analysis. Section 3 compares centralised and decentralised models in terms of energy efficiency, the first rough performance indicator. Section 4 sets out the methodology adopted to evaluate the internal and external benefits of distributed generation. Internal benefits are calculated by simulating optimal prices of the electricity and natural gas inputs. Moreover, in order to consider the territorial effects (i.e. «customer density» variability) and simulate geographic marginal costs, two econometric models of electricity and gas distribution costs are developed. The external costs and benefits of both centralised and decentralised systems are assessed by using the "ExternE" methodology, one of the most accurate approaches recently developed in this field. In this respect, we take care to separate local-regional and global effects. In fact, this distinction is useful to isolate the impact of statistical and political uncertainty, which mainly regards to global warming cost estimations. Section 5 focuses on fully decentralised models. The results are presented in terms of density and cumulative probability distributions and take into account both the territorial parameter dispersion and the uncertainty of external cost estimates. The section subsequently analyses the robustness of these results by verifying their sensitivity to the variability of some structural parameters considered fixed in the base case. Section 6 analyses the case of hybrid models in order to see whether we are facing a "convex" world, that is, whether there is an internally solution which is better than the fully centralised and decentralised models. Section 7 includes some observations regarding two relevant topics related to the DG issue: the impact of energy market reforms and the effectiveness of the environmental policies focusing on the reduction of greenhouse-gas (GHG) emissions. Section 8 deals with the possible impact of incoming technological innovations, with particular focus on the potential effect of the use of fuel cells. The final section summarises the main results of the paper.

□ **Related literature**. The topic of this paper ties in with the main research fields of microeconomic theory: pricing regulations of public utilities, the relationship between technological change and market organisation, the economic evaluation and internalisation of externalities and the use of cost-benefit analysis to assess the impact of market reforms.

As regards pricing regulation, we have analysed the traditional literature on peak-load pricing methodology originally set out by Steiner (1957) and Boiteaux (1956) and later fully developed by other authors (see Pressman, 1970 and Crew and Kleindorfer, 1986). We have made very few incursions in the world of non-linear tariffs. Worth mentioning is the study by Wilson (1993) which gives a broad overview of the general theory and the one by Electricité de France-Service des Etudes Economique Générales (1979) which provides a useful application of marginal cost pricing to the case of electricity supply.

Since distributed generation is a sort of bypass technology involving competition between electricity and natural gas utilities, we have also referred to the literature on cream skimming, bypass and regulated competition. In this field, Curien, Jullien, and Rey (1998) explore optimal pricing regulation under bypass competition in the case of telecommunications and Laffont and Tirole (1993) focus on the problems of asymmetric information between regulator and operators. Based on the original works by Baumol and Bradford (1970) and Baumol, Panzar, and Willig (1982), Brauetigam (1984) analyses the case in which even bypass technology is regulated, that is, when bypass involves competition between two natural monopolies. These contributions help us understand whether hybrid solutions (in our case, centralised and decentralised systems operating together) might be the social optimum.

As regards the relationship between technological change and market organisation, distributed generation occupies a precise place in the literature on energy and public utilities economics. Several papers deal with this topic and the Energy Journal has recently published a special issue with several interesting contributions. Some are specific (Sharma and Bartels, 1997; Either and Mount, 1997; Morse, 1997) and others more generic (Pfeifenberger et. al., 1997). The authors give a moderately optimistic picture of DG development and emphasise the importance of industry and price unbundling in determining its economic viability, at least in some specific market niches. However, even in this case, the results of the analysis are only partially useful for our purposes. In fact, they focus on private competitiveness while this paper takes a rather different approach since it is based on overall social value and not only on private economic viability.

With regard to social cost-benefit analysis we have referred to the methodology developed by Jones, Tandon and Volgesang (1990) and the several applications by Newbery and Pollitt (1997) 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.

Since distribution costs (of both electricity and natural gas) affect DG benefits, we also analysed the related literature which can be divided into two groups of contributions. The one emphasising economies of scale (Roberts, 1986; Nelson and Primeaux, 1988, Salvanes and Tjoota, 1994) and the one emphasising the importance of economies of density (Filippini, 1998; Folloni, 2001; Gullì, 2000). This paper mainly refers to second group.

References to external cost literature need to be more detailed, not only because this is particularly extensive but also because the debate on this topic is still controversial. Several authors in fact question the reliability of the methodologies developed to estimate the monetary value of external environmental effects. Their arguments mainly focus on the considerable uncertainty of estimations (mainly about global warming) which would make them less effective in informing environmental policies. These authors notably include Stirling (1997) who provides some interesting arguments to support his thesis. However, we will try to demonstrate that such scepticism is perhaps exaggerated and that external cost methodologies can be very useful despite the considerable uncertainty regarding specific categories of environmental damage. In this paper we use the “ExternE” approach which is one of the most recent and reliable methodologies in this field. It was developed by a group of leading European and US research centres 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. More detailed information regarding this methodology and its application are reported in a series of reports published by the European Commission (European Commission, 1995a, 1995b, 1995c, 1997a, 1997b, 1997c, 1997d, 1998a, 1998b).

Finally, we should mention some important specific contributions on distributed generation provided by non-academic institutions and consulting companies including the reports by NARUC (National Association of Regulatory Utility Commissioners) prepared in the framework of The Regulatory Assistance Project (2000a, 2000b, 2000c, 2001) and the detailed documents of the US Department of Energy prepared by Arthur D. Little (1998, 1999, 2000). These contributions have been precious sources of information and very helpful in understanding some technical and economic issues related to distributed generation deployment.

2. General approach

■ DG raises several economic issues for regulators and legislators: What is the real social benefit of distributed generation? Is this benefit sufficient to promote a transition towards a widely decentralised organisation? In other words, is DG the new paradigm of the network energy industry? Searching for a paradigm implies some basic methodological choices and assumptions which can be explained by answering the following questions.

First, what should our evaluating criterion be? The choice is quite simple. Since we are searching for a social paradigm, the criterion should be a social welfare comparison (between centralised and decentralised supplies) and the related analytical tool a cost-benefit analysis.

Second, what kinds of situations should be analysed: “ideal” or real situations? In this respect, 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.

Third, which category of DG benefits should be considered? We believe that, since we are dealing with “ideal” situations, only the structural benefits should be taken into account, excluding benefits and advantages due to specific market organisations. The particularly controversial case of price volatility in the power sector can help us explain this choice. High price volatility can be due to market power and/or supply scarcity.

In the case of market power, distributed generation reduces the risk of price volatility because it increases the elasticity of demand. Nevertheless, since this advantage is the result of a market distortion (and as such is not a benefit in absolute terms), it must not take into account when we deal with an “ideal” framework.

The case of the supply scarcity is less clear from this point of view. Divergences between supply and demand can, in fact, create price fluctuations in addition to the effects of market power. We should therefore ask ourselves whether such divergences are possible in "ideal" situations. On the one hand, perfectly competitive systems should provide optimal price signals to operators (in order to plan their investments) and customers (in order to adjust their consumption decisions) so that price volatility is absent or at least minimised. On the other hand, in an optimal-regulated monopolistic market, the firm should be able to perfectly adapt its offer to demand. But again price fluctuations, even though minimised, might not be completely eliminated because of the unavoidable uncertainty regarding the evolution of demand over time. In conclusion, although price fluctuations are bound to exist even in "ideal" situations, they are certainly lower than those that occur in real situations. This means we can legitimately disregard them and consider in our analysis only DG structural benefits from combined heat and power generation (explicitly) and avoided electricity transmission costs (implicitly).

Fourth, what kinds of applications and technologies should be examined? Since the simulation must be representative of large potential DG deployment, we should not analyse specific applications or technologies which are not significant of a paradigmatic change (i.e. renewable energy sources). We therefore have to deal with fossil fuel plants (especially natural gas fired technologies[2]). As regards the applications, we will proceed as follows. We will first deal with applications for residential uses (i.e. the largest customer category[3]) and "isolated" solutions (see the next paragraph), in order to simulate fully decentralised models of supply (in this case, centralised supply and distributed generation are analysed separately: a fully centralised model versus a fully decentralised model). Subsequently, we will analyse "open" solutions and "isolated" solutions applied to customers larger than the residential ones (the case analysed will be a hospital[4]), in order to consider hybrid models (in which distributed generation and centralised supply co-exist).

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 three categories. The first includes variables which change significantly over time (i.e. natural gas price). In order to consider the impact of their variability on DG benefits we will carry out a sensitivity analysis. The

[2] Since 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.

[3] This kind of application represents a conservative case involving a low ratio of heat and electricity consumption. In fact, although industrial customers are more favourable to CHP, it would not be representative of a paradigmatic change.

[4] We do not take into consideration applications which involve power plant capacity higher than 10 MW, since this threshold power generation is considered centralised (generation which does not bypass the electricity transport grid).

second category includes variables which can change over "space" (i.e. electricity and gas distribution costs). Their impact will be considered by estimating density distributions (assessed through econometric models) and directly using them in the model. The last 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 (for example, in Milan) and in the south (for example, 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[5]).

As mentioned earlier, this paper utilises the social cost-benefit analysis, a methodology widely used when evaluating public investment choices. However, it has recently been adapted to study the social impact of industry restructuring policies with emphasis on privatisation. In this new version, a full social cost-benefit analysis would involve determining the net welfare difference and its distribution. We should therefore be able not only to evaluate the overall impact on economic efficiency but also to identify who gained, who lost and by how much. Therefore its main concerns should be economic efficiency and equity.

We are not, however, concerned with equity issues since we are only interested in the overall welfare change. Moreover, since we are dealing with "ideal" situations, consumers would gain all the possible increases in social welfare due to DG deployment thus excluding possible allocative inefficiency due to market power and considering only allocative distortions related to market incompleteness due to externalities. Figure 2 schematically illustrates this procedure. Let us assume two alternative supply models: model 1 (i.e. centralised supply) and model 2 (i.e. distributed generation). According to Newbery (2001), we can assume that the public utility of the model 1 set price p_1 equal to unit cost sc_1 (which in this case is equal to the average and marginal cost and includes the normal return on capital) and sold the optimal quantity q_1. Model 2 leads to a fall in average and marginal cost to sc_2 and demand increases to q_2. Therefore the effect of replacing model 1 with model 2 is an increase in social welfare equal to $\overline{\Delta W}$ plus the area $L = \Delta sc \cdot \Delta q / 2$. If the elasticity of demand (as a positive number) is ε, then $L \approx \varepsilon sc_1 q_1 (\Delta sc / sc)^2 / 2$. The ratio of L to original cost (revenue) $sc_1 q_1$ is $\varepsilon(\Delta sc / sc)^2 / 2$. If the "cost saving" is also expressed as a fraction of original cost (revenue), $sc_1 q_1$, then $sc_2 \Delta sc / (sc_2 q_2) = \Delta sc / sc_2$, which may be directly compared with

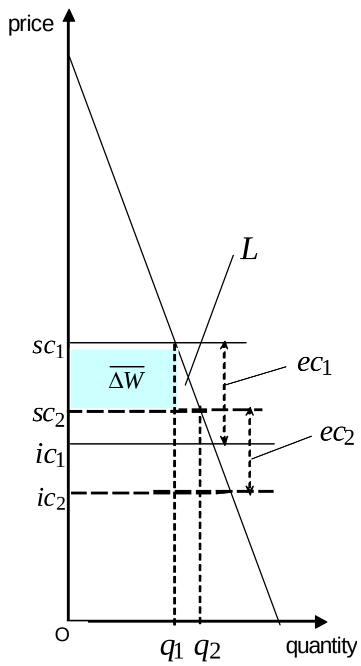
[5] Moreover, Milan and Palermo also differ in terms of climate conditions (cold in the first case and mild in the second) which influence CHP costs (the lower the heat needs for domestic heating and/or air conditioning, the higher the CHP costs). We can therefore observe this effect without introducing an explicit variable in the estimating model.

the proportional combined effect. For example, if the demand elasticity ε=0.1, and if $\Delta sc / sc_1 = 20$ percent, then the combined effect will be 0.2 percent (of cost), two order of magnitude lower. Therefore, since the elasticity of demand in the residential sector is extremely low, the area L can be disregarded and the change in social welfare, as a proportion of original costs, is

$$(1)\ \Delta w = \frac{\overline{\Delta W}}{sc_1 q_1} = \frac{sc_1 - sc_2}{sc_1} = \frac{ic_1 - ic_2}{ic_1} \cdot \frac{ic_1}{sc_1} + \frac{ec_1 - ec_2}{ec_1} \cdot \frac{ec_1}{sc_1}$$

where sc, ic and ec are respectively social, internal and external costs per unit supplied.

Figure 2 – Cost-benefit of technological change



Equation (1) alone cannot be the right criterion to determine whether DG is the new paradigm. In fact, $\Delta w > 0$ is neither a necessary nor sufficient condition to accept DG as the new paradigm because this also depends on the difference in transaction costs between centralised and decentralised supplies. We therefore have to ask ourselves which involves higher transaction costs.

In this respect, we have to recognise that decentralised models increase investment specificity, uncertainty and transaction complexity. Each small plant is designed and sized to satisfy the needs of a specific customer in terms of consumption level and profile. On the contrary, a large centralised plant is designed and sized to supply energy to a large number of customers whose consumption profiles are partially complementary. Therefore, DG involves investment specificity higher than that of large power generation.

Moreover the owner of a small plant (on the customer side of the meter, which is the relevant perspective of our analysis) has to manage a number of contractual relationships not only with gas suppliers but also with electricity suppliers (to contract power exchanges and ancillary services). This increases uncertainty and complexity, which, combined with high specificity, determines higher transaction costs. Therefore, given the need to consider this effect, the evaluation criterion could be the following.

$\Delta w < 0$ is a sufficient condition to reject DG as the new paradigm. In order to accept DG as the new paradigm, the change in social welfare must be positive and higher than a specific threshold γ, related to the difference in transaction costs.

Unfortunately, we do not know what this threshold is and the economic literature does not provide information in this respect. Nevertheless, for the moment it is sufficient to realize that the possible increase in social welfare due to DG deployment must be high enough to cover the increased transaction costs.

3. Energy saving

■ Before assessing DG internal and external benefits, it is necessary to compare centralised and decentralised systems in 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). Customer energy needs, including heat for domestic heating and cold for air conditioning, depend on plant location (Milan or Palermo) while the structural electricity needs are assumed to be identical (see table A1 of the Appendix).

□ **Centralised systems**. Solution A includes a conventional condensing boiler 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 combined cycle-gas turbine plant (CCGT), with 51% 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.

□ **Decentralised systems**. Solution C1 produces combined heat and power by using a gas engine technology. 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 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 51% electrical efficiency). Therefore, net primary energy is equal to DG fuel consumption minus the avoided fuel consumption.

D1 and D2 systems are "isolated» since they do not involve importing/exporting electricity from/to the utility grid. 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) are supplied by a reversible heat pump using cogenerated power. Solution D1 uses a gas engine whereas solution D2 a gas turbine.

□ **Results.** Table 1 shows that primary energy consumption of the decentralised solutions is always lower than that of the centralised solutions and depends considerably on technologies and locations (the technical data of the plants are reported in the Appendix). 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 case ("open" gas engine in Milan), energy saving can reach 40%, a value high enough to encourage us to continue our analysis in order to verify DG performance in terms of social benefits.

Table 1 – Primary energy consumption and energy saving

	Centralised systems			**Decentralised systems**							
				"Open"				"Isolated"			
	A	B		C1		C2		D1		D2	
	Primary Energy	Primary Energy	B/A	Primary Energy	C1/A	Primary Energy	C2/A	Primary Energy	D1/A	Primary Energy	D2/A
	MWh/y	MWh/y		MWh/y		MWh/y		MWh/y		MWh/y	
Milan											
Residential	5.678	4.762	0.84	3.394	0.60	4.690	0.83	3.898	0.69	4.412	0.78
Hospital	58,765	51,924	0.88	40,131	0.68	49,907	0.85	42,598	0,72	48,230	0.82
Palermo											
Residential	4.852	4.102	0.89	3.036	0.66	4.160	0.86	3.387	0.70	3.890	0.80
Hospital	52,045	47,572	0.91	37,922	0.73	46,561	0.90	39,955	0.77	45,563	0.88

4. Methodology

4.1. Internal cost/benefits

■ In this section we attempt to measure DG internal benefits. Following the general approach illustrated above, we have to assess the internal costs of centralised and decentralised supplies.

The crucial step in assessing the internal costs is to simulate the optimal prices of electricity and gas inputs. Given the characteristics of the demand of such inputs, 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[6]. 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.

□ **The model**. To simulate optimal prices of the electricity and gas supplies, 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. 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 staring point of such a method is to evaluate the additional expenses the utility must sustain to serve a new customer with a given consumption profile over time (see Appendix):

$$(2)\ \Delta C = f_1 \cdot \Delta P_1 + \sum_{i=1}^{n} v_i(H) \cdot \int_{H_{i-1}}^{H_i} \Delta P(H) dH$$

where $\Delta P(H)$ is the capacity demand profile over time of the new customer, with ΔP_1 its peak demand, $v_i(H)$ is the variable cost of the technology used for H hours in the year and f_1 the fixed cost of the peak technology.

Equation (2) can be modified in order to obtain an approximate formulation very useful for our purpose. Assume a new customer with annual consumption E and contractual capacity P. Let $f(P(H), E) = \Phi(H)P$ be the measure of his responsibility in inducing the increase in peak capacity, where H is the number of full consumption hours per year, and $\Phi(H)$ is the peak probability consumption that is the probability the new customer might consume during the peak hours, with $\Phi(H) \in [0,1]$ and $d\Phi(H)/dH > 0 \ \forall H \in [0,T]$. The equation (2) then becomes

$$(3)\ \Delta C(P,E) = \mu \cdot E + \delta \cdot \Phi(H) \cdot P$$

where $\delta = f_1$ and $\mu = \sum_i v_i(H) \int_H \Delta P(H) dH \Big/ \int_H \Delta P(H) dH$ are respectively the fixed and the average variable components and $E = \int_H \Delta P(H) dH$.

From equation (3) it is possible to express the optimal price per unit of consumption as

[6] 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 approximation has only a marginal impact on the results of this analysis.

(4) $p = \dfrac{\Delta C(P,E)}{E} = \mu + \delta(\theta) \cdot \dfrac{\Phi(H)}{H}$

Note that the fixed component is function of a parameter θ. This parameter is introduced in order to take into account the "spatial" effects, such as the differences in costs due to customer geographic density variability (in first approximation, it is justified to disregard the influence of the territory on the variable components).

Equation (4) represents the classical two-part tariff and is very useful for our purposes. In fact, it is sufficient to apply this simple formula at each stage of the electricity and gas industries (figures 3 and 4) in order to obtain the total optimal price of the input *k*:

(5) $p_k = c_g + \sum_m \left[\mu_{km} + \delta_{km}(\theta_k) \cdot \dfrac{\Phi_k(H_k)}{H_k} \right]$

where c_g is the natural gas price, μ_{km} and δ_{km} are respectively the variable and fixed costs in the *m* stage, $\Phi_k(H_k)$ the peak probability demand (with $H_k = E_k / P_k$) and $\theta_k \in \left[\underline{\beta}_k, \overline{\beta}_k\right]$ the territorial parameter.

Note that we assume $\Phi(H) = 1$ in the cases of gas and electricity low voltage (LV) distributions. There are two reasons for this assumption. On the one hand, in these industry segments, geographic effects are more relevant than the "over time" effects. On the other hand, 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 is less relevant than in the case of electricity and gas transport or power generation.

By using equation 5 and taking into account DG investment costs *IC* and discounting over time, we can finally find the expression of the internal costs, respectively for centralised, "isolated" and "open" decentralised solutions:

(6a) $INTC_{CENTR} = \displaystyle\int_{t=0}^{T_1} \left[p_g(\theta_g, H_g; t) \cdot E_g(t) + p_e(\theta_e, H_e; t) \cdot E_e(t) \right] \cdot e^{-r \cdot t} dt + IC$

(6b) $INTC_{DG}^{isolated} = \displaystyle\int_{t=0}^{T_1} \left[p_g(\theta_g, H_g; t) \cdot E_g(t) + \delta^*{}_e \cdot P_e \right] \cdot e^{-r \cdot t} dt + IC$

(6c) $INTC_{DG}^{open} = \displaystyle\int_{t=0}^{T_1} \left[p_g(\theta_g, H_g; t) \cdot E_g(t) + p_e^{GT}(\theta_e, H_e; t) \cdot E_e^{net}(t) + \delta^{**}{}_e \cdot P_e^{DG} \right] \cdot e^{-r \cdot t} dt + IC$

where T_1 is the plant lifetime, assumed the same for all plants, and r is the discount rate. $E_e^{net} < 0$ is the net electricity exported to the grid, P_e^{DG} is the power size of the "open" DG plant and P_e the maximum capacity need of the customer. Notice that even in the case of "isolated" solutions there must be an electricity distribution grid to provide ancillary services and permit the occasional exchange of electricity (for example, when the consumption profile of the customer differs from that assumed). δ_e^{*} and δ_e^{**} are the cost of grid interconnection respectively in the case of "isolated" and "open" solutions[7]. Given equations (6a), (6b) and (6c), and according to the methodological approach, DG benefits are

$$(7)\quad INTB_{DG} = 1 - \frac{INTC_{DG}}{INTC_{CENTR}}$$

[7] The typical cost of grid interconnection ranges from 50–200 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).

Figure 3 – Value chain of the centralised model

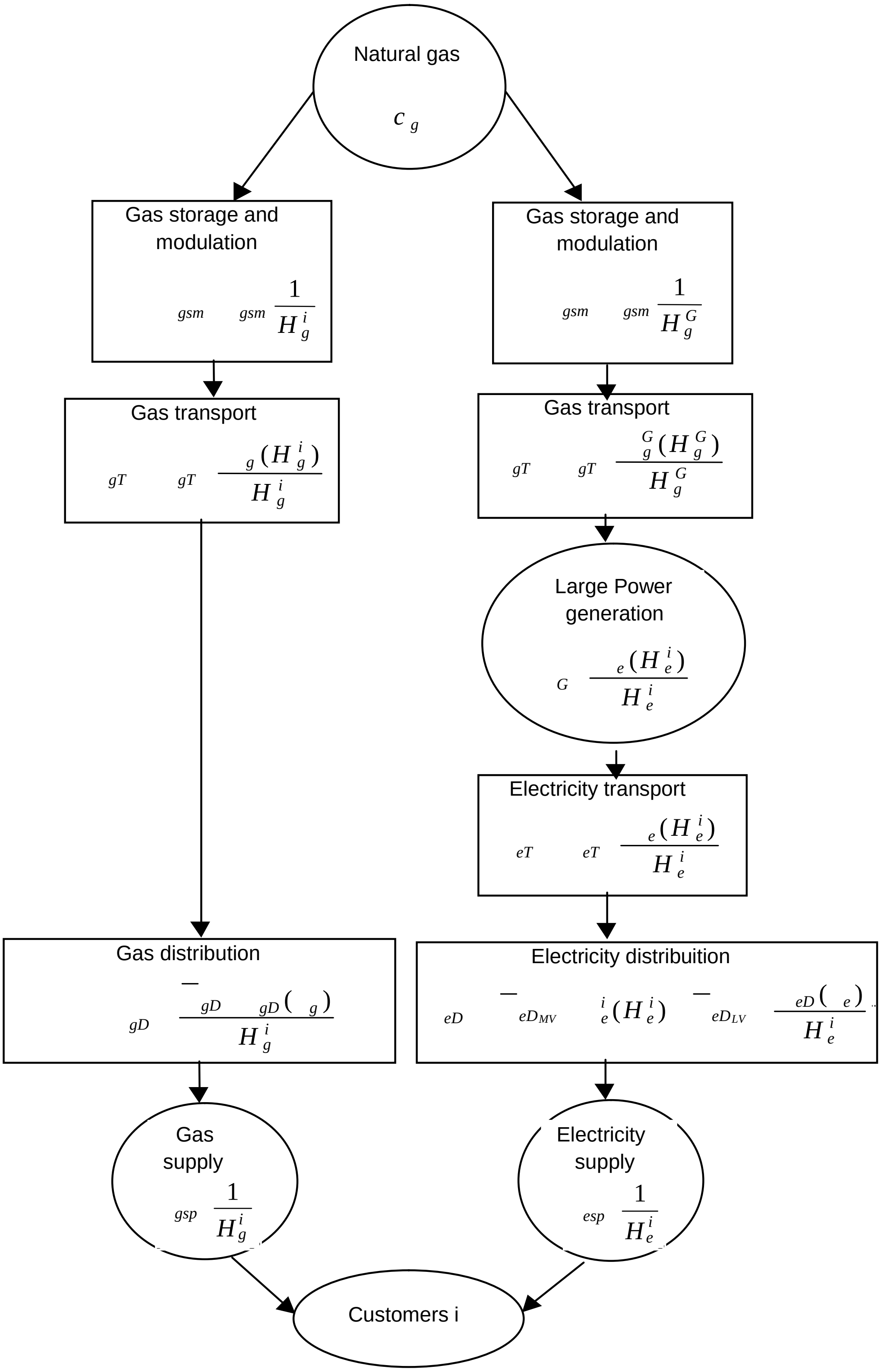
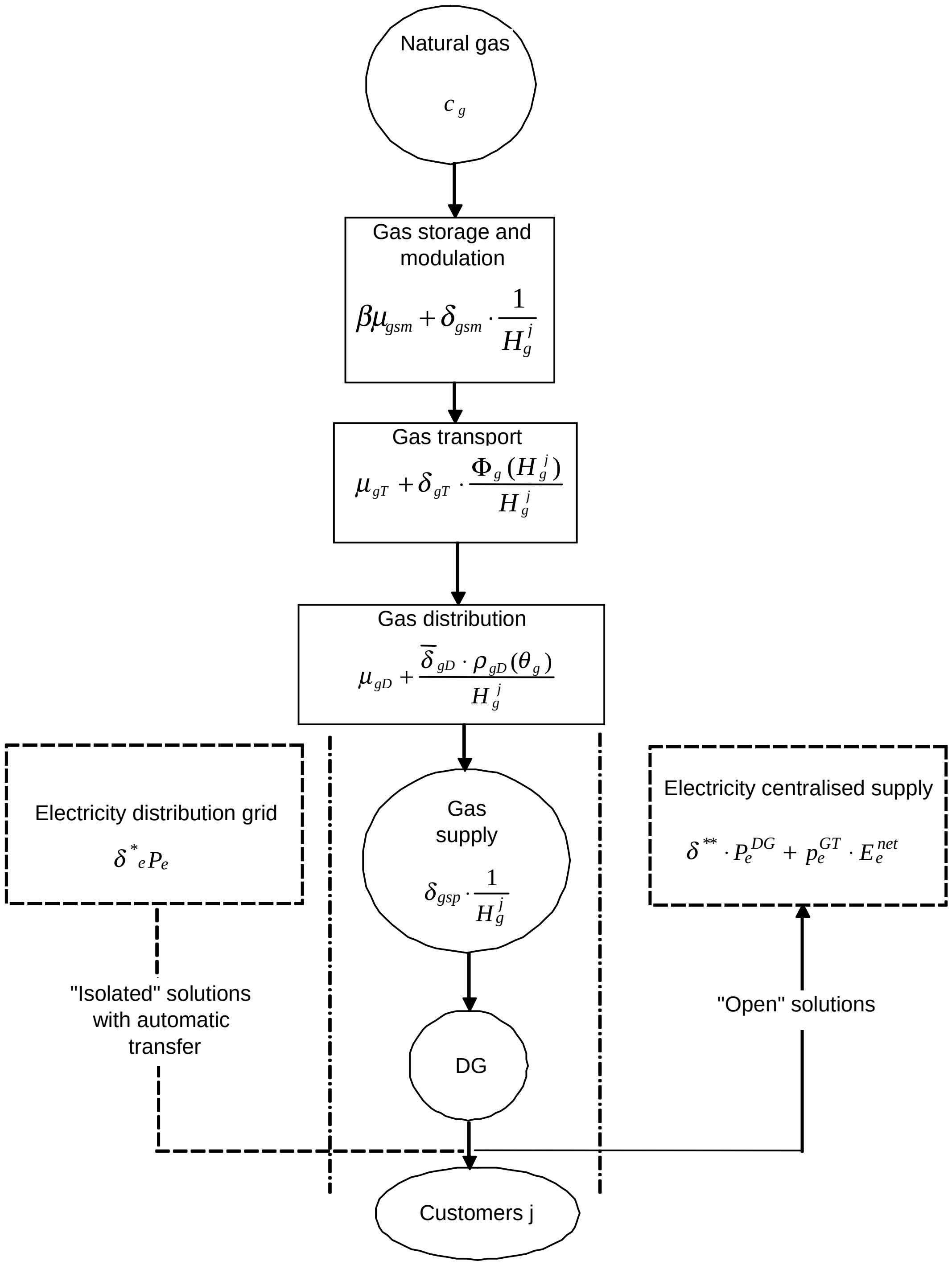


Figure 4 – Value chain of the decentralised model



There is one last step in the application of equations (6) and (7): evaluating how the fixed price components depend on «customer density». For this purpose we carry out two econometric models, one for electricity distribution costs and the other for gas distribution costs.

It should be noted that «customer density» is an exogenous parameter which represents customer concentration on the territory. Although the best indicator of territorial customer concentration is the number of customers per unit of geographic area (i.e. number of customers per km^2), it is difficult to collect information about the extension of the area distribution of a utility. Therefore, an alternative indicator is generally used, namely, the number of customers divided by the length of distribution lines (or the length of gas distribution pipelines), which is a good proxy of the territorial density of the customers.

Electricity distribution costs. The economic literature is quite controversial regarding the determinants of electricity distribution costs. On the one hand, several estimation models (Roberts, 1986; Nelson and Primeaux, 1988, Salvanes and Tjoota, 1994) emphasise the importance of economies of scale but disregard the economies of density. These models, based on the elaboration of samples of different distribution utilities, do not seem to be well formulated so that in some cases the differences in distribution costs due to «customer density» dispersion are attributed to efficiency gaps or to input price disparities (Gullì, 2000). On the other hand, more recent analysis partially eliminates this ambiguity by proposing estimates which clearly demonstrate the importance of economies of density in determining distribution costs (Filippini, 1998; Gullì, 2000; Folloni 2001). The model we present below belongs to this last category. It is particularly significant since it is based on data-series of the distribution areas of a single utility (Enel, which is the dominant distribution utility in Italy). The econometric analysis of these data allows us to clearly separate the effects of economies of scale and density:

$$(8)\quad \begin{cases} \ln TC_{eD} = \underset{t\qquad(4.4)}{1.474} + \underset{(26.4)}{0.826}\ln CL_e + \underset{(7.5)}{0.240}\ln\theta_e + \underset{(4.9)}{0.111}DUM_e \\ r^2 = 0.84 \end{cases}$$

TC_{eD} is the total cost of electricity distribution, CL_e is the total number of customers supplied at medium and low voltage and θ_e is the inverse of the territorial «customer density» (the number of customers divided by the length of distribution lines). DUM_e is a dummy which discriminates between the distribution areas of Centre-North of Italy ($DUM_e = 0$) and those of the South of Italy ($DUM_e = 1$).

Since model (8) is based on data referring to1996[8], it cannot be directly used for our purposes. Nevertheless, since we do not need absolute values but only an indicator of their geographic dispersion (that in an initial approximation can be assumed constant over time), model (8) can be used to calculate a normalised cost function representing distribution cost normalised to its average value. However, before normalising, equation (8) must be reformulated in order to "neutralise" the

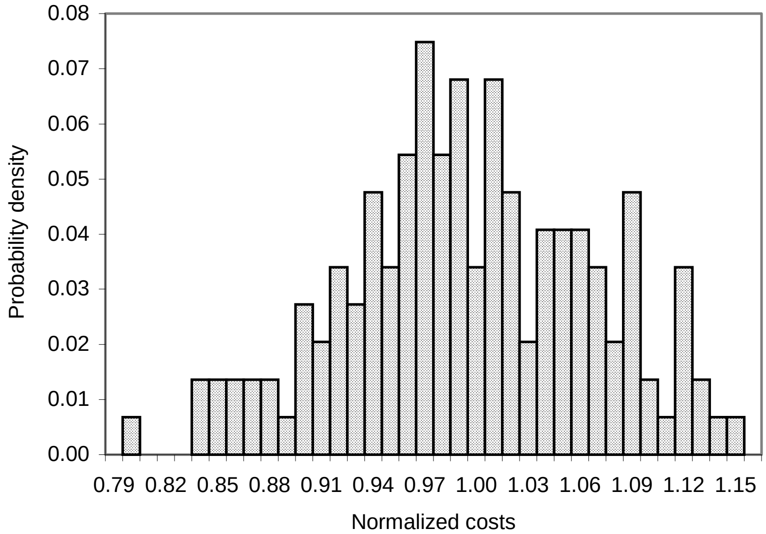
[8] Values are in 1996 ITL. Since we are concerned with normalised costs, it is not necessary to convert these values to USD.

effects that are not due to «customer density» dispersion, first of all those deriving from economies or diseconomies of scale. Since we are, in fact, dealing with ideal situations we should imagine that all firms, or distribution areas, are optimally sized. Since effects of scale are captured by the coefficient a_1, in order to obtain the "neutral" function we must convert model (8) to exponential form and divide by the term $CL_e^{0.826}$. Therefore, equation (8) becomes

$$(9) \quad NTC_{eD}(CL_e, \theta_e) = 4.367 \cdot \theta_e^{0.240} \cdot EF$$

where $EF = e^{0.111 DUM_e}$, with $EF = 1$ when $DUM_e = 0$ and $EF = 1$ when $DUM_e = 1.117$.

Figure 5 – Density distribution of electricity normalised distribution costs



By dividing (9) by the average value of the "neutral" cost we can obtain the normalised cost which is the parameter representative of the territorial dispersion of electricity distribution costs:

$$(10) \quad \rho_{eD}(\theta_e) = \frac{NTC_{eD}(\theta_e)}{\overline{NTC}_{eD}}$$

where $\overline{NTC}_{eD}$ is the average value of the normalised costs. Figure 5 illustrates $\rho_{eD}(\theta_e)$ density distribution for the data set of the electricity distribution areas in Italy.

Finally, by multiplying the fixed components of the optimal distribution prices by $\rho_{eD}(\theta_e)$, we can simulate the impact of the «customer density» variability on the electricity distribution costs:

$$(11) \quad \delta_{eD} = \overline{\delta}_{eD} \cdot \rho_{eD}(\theta_e)$$

Natural gas distribution costs. The economic literature on natural gas distribution costs is less extensive than the one on electricity distribution costs. The study carried out by AEEG (2000) is the only one available on Italy. Since only the final results of this study have been published, we do not know the characteristics of the sample used and therefore cannot propose our own elaboration. We therefore have to use the AEEG model without checking its reliability. This study separately analyses operating and capital costs. As regards operating costs, the proposed estimation model is the following:

$$(12)\begin{cases} \ln OPC_{gD} = \underset{(5.5)}{112.196} + \underset{(47.7)}{1.051} \ln CL_g + \underset{(2.6)}{0.209} \ln \theta_g \\ \quad t \\ r^2 = 0.98 \end{cases}$$

where OPC_{gD} are the operating costs, CL_g is the number of customers (medium and low pressure) and θ_g is the inverse of «customer density» (number of customers divided by the length of gas distribution pipelines).

As regards capital costs, a direct estimation of the unit cost (per customer) is proposed:

$$(13)\begin{cases} \ln CCPC_{gD} = \underset{(31.4)}{12.089} + \underset{(14.4)}{0.649} \ln \theta_g - \underset{(-2.8)}{0.011} \ln Z + \underset{(3.8)}{0.111} \ln POP \cdot + \underset{(2.3)}{0.035} \ln GF \\ \quad t \\ r^2 = 0.85 \end{cases}$$

where $CCPC_{gD}$ are capital costs per customer, Z is a parameter representing territorial shape (flat, hill or mountain), POP is the population (number of habitants), $GF = (POP - 500{,}000)$ if $POP > 500{,}000$ e $GF = 1$ if $POP \leq 500{,}000$ (this dummy is introduced to distinguish the urban centres (densely populated) and the rural territories (sparsely populated).

Since the data refer to 1998, they can not be directly used in our study. However, like the previous case, it is sufficient for our purposes to calculate a normalised function. Therefore, by exactly following the proceeding adopted in the case of electricity, we get

$$(14) \quad NTC_{gD} = NOPC_{gD} + NCCPC_{gD} = 198002{,}03 \cdot \theta_g^{\ 0.209} + 177911.23 \cdot \theta_g^{\ 0.6485} Z_{flat}^{\ -0.011} \cdot GF^{\,0.035}$$

From (14) it is now possible to derive the parameter representative of cost dispersion in function of the «customer density»:

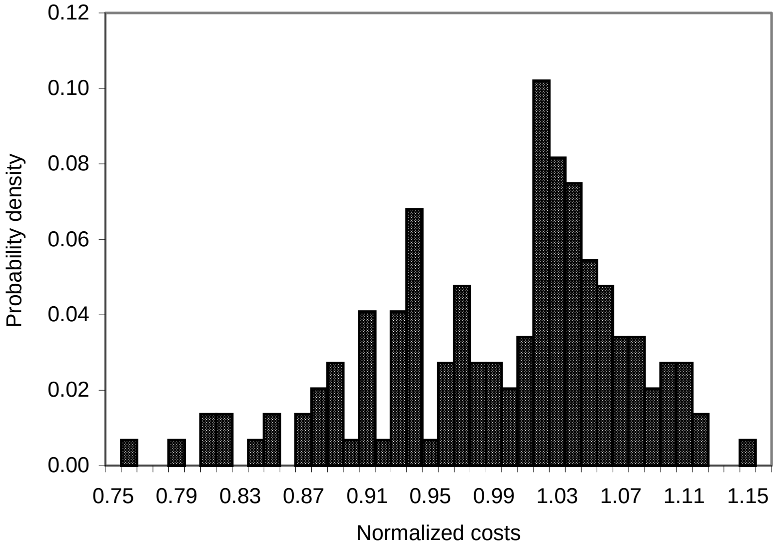
$$(15)\ \rho_{gD}(\theta_g) = \frac{NTC_{gD}(\theta_g)}{\overline{NTC}_{gD}}$$

Equation (15) allows us to simulate geographic marginal costs on using the analogous proceeding of the electricity case:

(16) $\delta_{gD} = \overline{\delta}_{gD} \cdot \rho_{gD}(\theta_g)$

The meanings of all the parameters are analogous to those already shown in the electricity case. Figure 6 illustrates the density distribution of $\rho_{gD}(\theta_g)$ values.

Figure 6 – Density distribution of gas normalised distribution costs



4.2. External cost/benefits

■ 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, amenities etc.. Our analysis only considers the effects of the main atmospheric pollutants (which represent the relevant part of the total damage).

Unlike internal costs, external costs can be permanent since they can appear many years after the plant lifetime and/or persist over time. For some categories of impacts this behaviour is negligible (i.e. local and regional effects) while for others (i.e. global warming) it is rather considerable so that the time damage horizon T_2 can be much higher than the plant lifetime T_1.

These introductory remarks are meant to explain why we will distinguish local-regional effects (essential due to SO_X, NO_X and particulate emissions) and global impact (due to GHG emissions).

The total external cost EC can be expressed as

(17) $EXTC = \sum_z \alpha_z \overline{Q}_z$

where z is a generic pollutant,

(18) $\overline{Q}_z = \int_{t=0}^{T_1} Q_z(t)e^{-rt}dt$

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

(19) $\alpha_z = \dfrac{\int_{t=0}^{T_1}\int_{\vartheta=0}^{T_2} D_z(t,\vartheta)e^{-r\vartheta}dtd\vartheta}{\int_{t=0}^{T_1} Q_z(t)e^{-rt}dt}$

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 $D_z(t,\vartheta) = 0 \; \forall t > \vartheta$.

By using equation (17) we can finally find the expression of the external costs, respectively for centralized, "isolated" and "open" decentralized solutions:

(20a) $EXTC_{centr} = \sum_z \alpha_z^{centr} \overline{Q}_z^{centr}$

(20b) $EXTC_{DG}^{isolated} = \sum_z \alpha_z^{DG} \overline{Q}_z^{DG}$

(20c) $EXTC_{DG}^{open} = \sum_z \alpha_z^{DG} \overline{Q}_z^{DG} - \sum_z \alpha_z^{centr} \overline{Q}_z^{centrav}$

where $\overline{Q}_z^{centrav}$ is the avoided pollutant emissions of the large power generation (CCGT with 51% electrical efficiency[9]).

Given equations (20) and according to the methodological approach, DG benefits are

(21) $EXTB_{DG} = 1 - \dfrac{EXTC_{DG}}{EXTC_{centr}}$

In order to calculate the α_z coefficients, we use the "ExternE" methodology briefly described below[10].

□ **External cost coefficient evaluation**.[11]. The "ExternE" methodology[12] follows the *bottom-up* approach and is based on a *step-by-step* procedure. In fact, it requires dealing with cascade

[9] Minus the energy losses due to electricity transport and distribution (assumed equal to 6%).

[10] For a detailed description, see European Commission (1998a).

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

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 a local and regional scale; 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 global warming as a result of GHG 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 and difficult to quantify, especially as regards global warming estimations. Part of this uncertainty depends on social-political choices, which mainly reflect on the discount rate choice, while the remaining part is statistical. Statistical uncertainty regards both the physical/chemical phenomena and economic estimations. The former is essentially due to the difficulty of simulating the temperature increase and its profile over time due to GHG emissions. The latter mainly refers to the process impacting on monetary value of global warming, such as the forecast of economic development in the next one hundred years.

In order to isolate the problem of uncertainty, which mainly refers to global warming estimations, our analysis deals separately with local-regional effects (LR), mostly due to SO_x, NO_x and PM_{10} emissions, and the global effects (GW), due to GHG emissions. This distinction is also important because it allows us to identify the role of discounting in assessing external costs.

Local and regional effects (LR). Since local and regional effects are not permanent, by assuming D_z^{LR} constant over time, equation (19) becomes

$$(22)\quad \alpha_z = \frac{\int_{t=0}^{T_1}\int_{\vartheta=0}^{T_2} D_z(t,\vartheta)e^{-r\vartheta}\,dt\,d\vartheta}{\int_{t=0}^{T_1} Q_z(t)e^{-rt}\,dt} = \frac{D_z^{LR}\int_{t=0}^{T_1} e^{-rt}\,dt}{Q_z\int_{t=0}^{T_1} e^{-rt}\,dt} = \frac{D_z^{LR}}{Q_z}$$

Therefore SO_x, NO_x and PM_{10} coefficients do not depend on discount rate, thus allowing us to disregard the problem of social-political uncertainty. Furthermore, as statistical uncertainty about local and regional impacts is much lower than that related to global warming estimations, we do not

[12] This brief note on methodology content reflects the general description made by Valette (1995). See also the European Commission (1998a, 1998b).

take into account its effect, directly using the best guess of the related statistical distributions[13]. From (22) and by applying the ExternE model, we obtain the results illustrated in table 2.

Table 2 – External costs (ExternE model) per unit of pollutant (local and regional effects)

Sectors	Local and regional effects		
	SO_X	PM_{10}	NO_X
	USD/kg	USD/kg	USD/kg
Gas fired boiler and DG technologies			
Milan	20.9	42.9	21.0
Palermo	13.4	26.7	10.8
Large power plant (Combined cycle)			
Italy	9.5	11.4	9.3

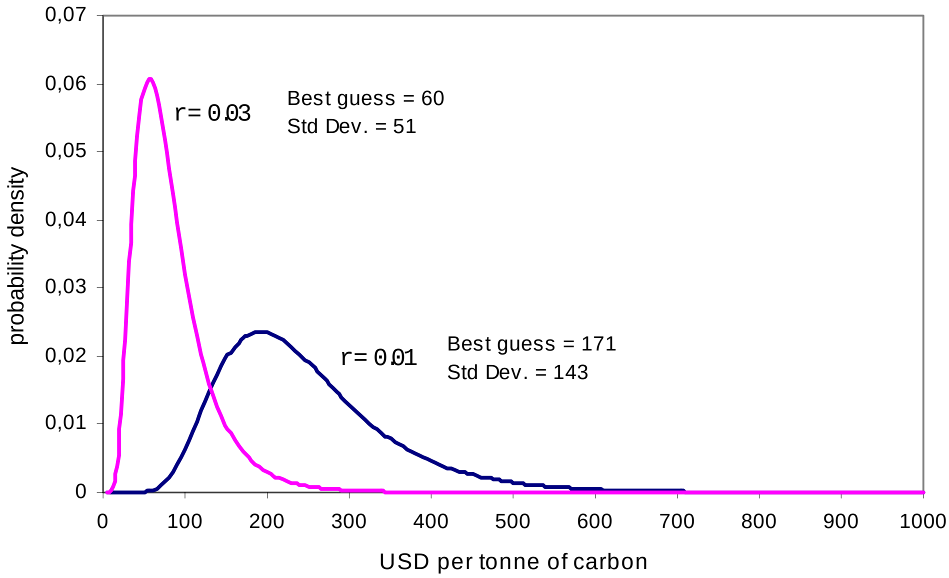
The following conclusions can be drawn from this table. First, local and regional effects largely depend on plant localisation. All other conditions being equal, external costs are much lower in Palermo than in Milan. This is due to the macro-localisation effect, thus confirming our preliminary intuition about the choice of geographic applications. Second, there are considerable differences between centralised and decentralised technologies, the first showing lower external cost coefficients. These differences are due to micro-localisation effects. In fact, unlike large power plants (high stack and extra-urban location) distributed technologies have low stacks and are generally located in densely populated urban areas. Because of low stack (emissions at extremely low quotas) pollutant atmospheric dilution is lower so that the increases in pollutant concentration close to the plant are greater 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. With the macro-localisation being equal, these combined effects cause an environmental impact (per unit of pollutant emitted) much greater than that of a large power plant.

Global effects. It is apparently easier to assess the external cost coefficients of global warming. The marginal damage (per unit of pollutant emitted) does not in fact depend on technology and plant localisation. Therefore, there is no need to implement specific simulations since it is sufficient to utilise the estimations already 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

[13] 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.

lognormal functions[14]. ExternE suggests[15] using a discount rate ranging from 1% to 3% whose density distributions, reported in figure 7, will be directly used in our estimating model in order to take into account the effects of both statistical and political uncertainty[16].

Figure 7 – Uncertainty regarding the marginal costs of carbon dioxide



Source: European Commission (1998b)

5. Fully decentralised models: results

5.1. Internal cost/benefits

■ Figure 8 illustrates the results obtained from applying equations (6a), (6b) and (7) and using the data reported in the Appendix[17]. These results are presented in terms of density distribution in order to show the impact of «customer density» dispersions. On the horizontal axis of the graphs the ratio of costs (DG costs divided by centralised system costs) is reported (the benefit is one minus the value of this indicator). The following conclusions can be drawn from this figure.

[14] 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 (1998a, 1998b).

[15] Regarding the problem of discounting in environmental cost-benefit analysis, see European Commission (1998a; 1998b).

[16] It is necessary to bear in mind that there are other GHG other than the 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 greenhouse potential is normally used: 3.8 in the case of CH_4 and 94 in the case of N_2O. For a criticism of this procedure see Schmalensee (1993).

[17] For the moment, we assume a discount rate equal to 1%, which is consistent with the range of values adopted for discounting the environmental monetary damage (see later).

First, value dispersions are very low, much lower than those of normalised costs themselves. This is an important result because it implies rejecting the commonly held belief that the structure of the territory could play a crucial role in determining DG competitiveness. In fact, this could be true, for example, in the case of renewable energy sources but not in the case of gas fired technologies[18].

Second, it clearly emerges that the framework of DG competitiveness is not very encouraging from the internal benefits point of view. In Milan, both gas engines and gas turbines provide benefits when compared to the conventional centralised solution but these benefits are almost negligible (not exceeding 8%). The picture is totally different when we compare DG technologies to the heat pump, the advanced centralised solution. DG never provides benefits, in the case of both gas engines and gas turbines. In Palermo, the results are even less encouraging. In all cases, DG never provides benefits.

In conclusion, the internal cost-benefit analysis does not confirm the optimistic framework emerging from energy efficiency comparison. Even though distributed generation assures significant levels of energy saving, its costs are still higher than those of centralised supply. However this result is not very surprising. Conventional DG is generally subsidised and generally considered competitive only in specific market niches although several authors emphasise its potential when used to provide combined heat and power. Therefore, the question shifts to the degree of DG environmental benefits which commonly inform the environmental policies supporting DG deployment.

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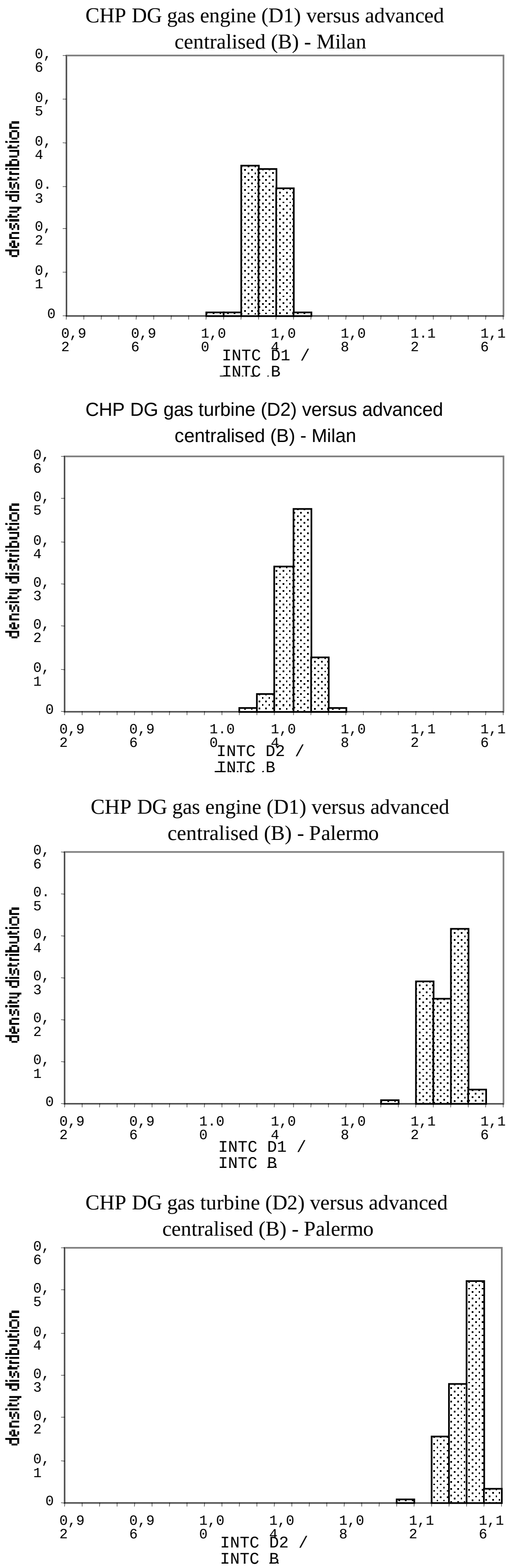
[18] This result can be easily explained. As the above-mentioned econometric models have pointed out, electricity and gas distribution costs depend on territorial parameters in a similar way. Therefore the ratio of centralised and decentralised costs cannot change very much with "customer density". As a matter of fact, a comparison between centralized production and distributed generation can also be regarded as a trade-off between scale economies and network effects. In theory, the internal benefits of distributed generation are greater where "customer density" is lower and vice versa. Therefore low customer density would be a first candidate for "isolated" DG. However, there are two reasons why this is only partly true. First, as previously pointed out, even in the "isolated" solutions, the development of DG needs a low voltage distribution network (distributed generation does not avoid the distribution costs, even though these are lower compared to the case of centralised supply). Second, the development of DG involves expanding gas consumption and therefore additional gas distribution costs which are higher where "consumer density" is lower. These additional costs partly counterbalance the partial savings on electricity distribution costs. In extremes, even in the long term (when everyone is self-supplying) the distribution network effects (electricity plus natural gas) are not huge. For these reasons in our model (which does not, however, capture short and medium term transitory effects) the internal benefits of DG are low sensitive to "customer density".

Figure 8 – Internal cost/benefits of distributed generation (“isolated” residential applications)



5.2. External cost/benefits

■ Before showing DG external cost-benefit in terms of density 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). The results are reported in table 3[19] which clearly shows that the total external costs sensible depend on the variability of the marginal cost of carbon dioxide. This confirms the need of considering the probability distribution instead of a single value.

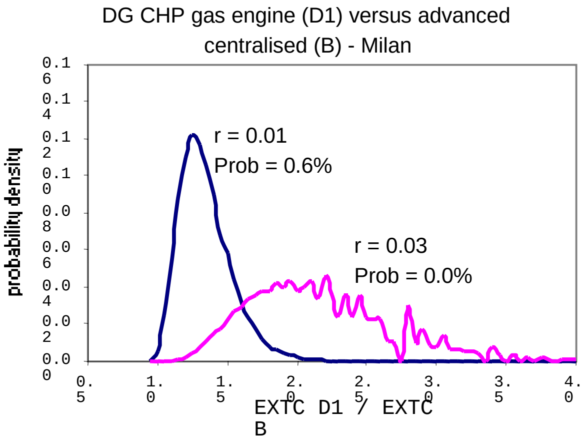
Table 3 – Emission rate and external costs per kWh of fuel

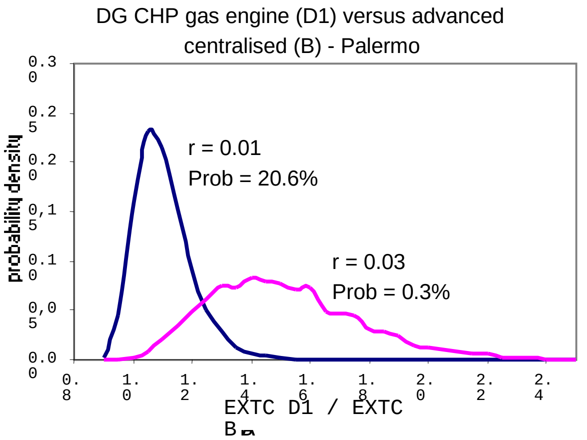
Sectors	Global effects (1)			Local and regional effects (1)					
	Emissions CO_{2eq}	Global External costs (best guess)		Emissions SO_x	PM_{10}	NO_x	Local and regional external costs	Total external costs (best guess)	
		(r = 1%)	(r = 3%)					(r = 1%)	(r = 3%)
	(g/kWh)	(USD/t CO_2)		(g/MWh)	(g/MWh)	(g/MWh)	(mUSD/kWh)	(mUSD/kWh)	
Gas fired boiler									
Milan	202.7 (14.0)	46	16	1.7	0.0	32.9	1.61 (0.89)	10.93	4.85
Palermo	202.7 (14.0)	46	16	1.7	0.0	32.9	1.26 (0.89)	10.58	4.50
DG technologies									
Gas fired engine									
Milan	195.1 (14.0)	46	16	1.0	4.9	358.8	8.66 (0.89)	17.63	11.78
Palermo	195.1 (14.0)	46	16	1.0	4.9	358.8	4.90 (0.89)	13.87	8.02
Gas turbine									
Milan	197.3 (14.0)	46	16	1.0	9.8	140.7	4.28 (0.89)	13.36	7.44
Palermo	197.3 (14.0)	46	16	1.0	9.8	140.7	2.68 (0.89)	11.76	5.84
Large power plant (Combined Cycle)									
Italy	193.7 (14.0)	46	16	0.9	9.2	13.9	1.13 (0.89)	10.04	4.23

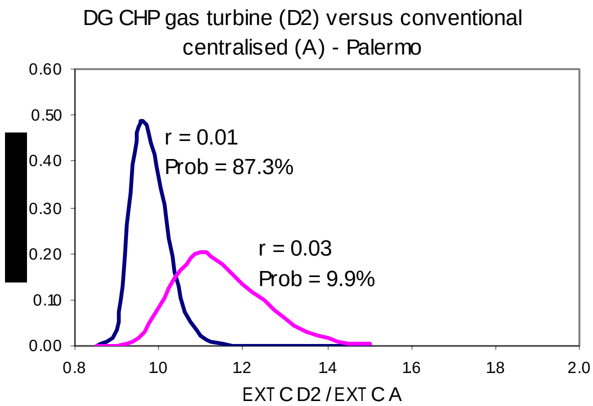
(1) Within brackets external costs of exploration, production and transportation fuel cycle stages.

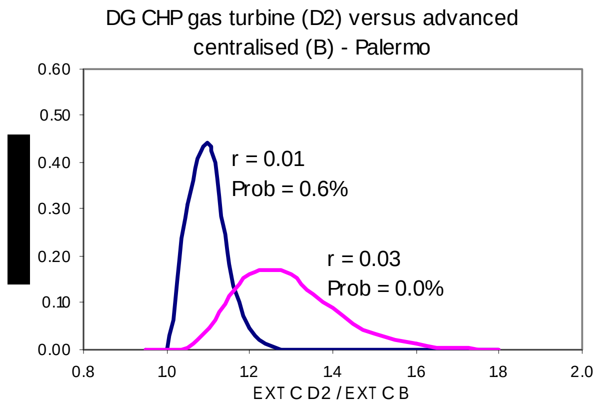
[19] Note that the coefficients include not only the external cost of power plant operation but also the monetary damage due to the upstream stages of the fuel cycles (exploration, production, transportation, etc.).

Figure 9 – DG external cost/benefits ("isolated" residential applications)







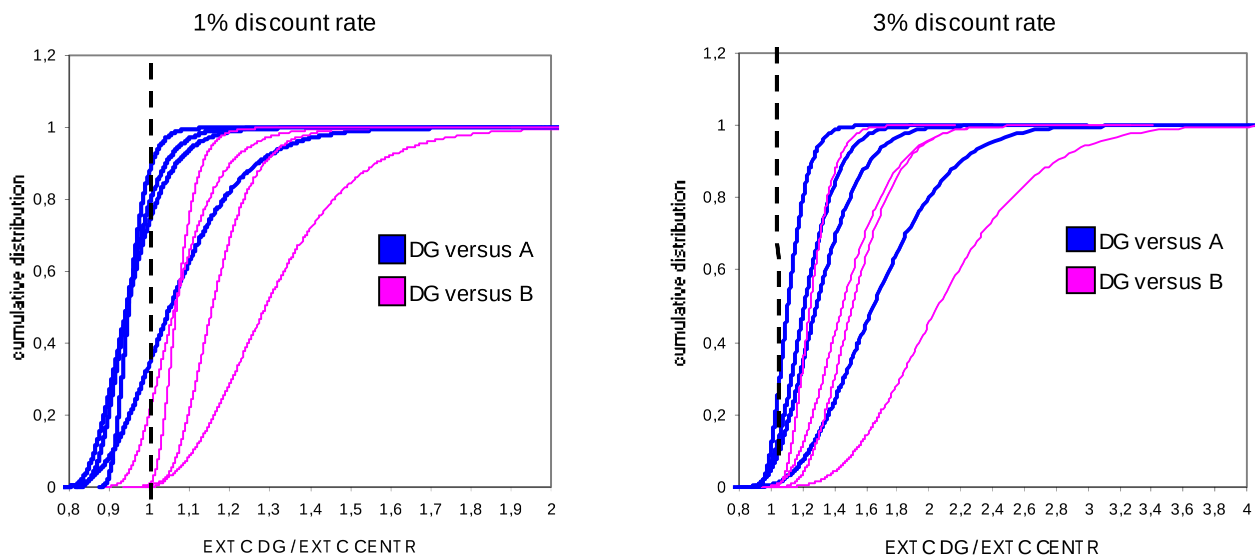


Given the estimates of the local and regional monetary damage reported in table 2 and the probability distribution of global monetary damage reported in figure 7, we can now calculate the external DG benefits in terms of density distributions (figure 9). We follow the same procedure adopted for the internal cost analysis, reporting 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 following conclusions can be drawn from Figure 9. First, the estimate dispersions are considerably lower than those of global warming cost estimations themselves, so that DG social cost-benefit can be clearly identified. Figure 9 bears this out quite clearly. In the case of gas engines in Milan, and compared to the conventional centralised system, there is a probability of around 30% that DG could provide benefits but this probability disappears using 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 but again DG never provides environmental benefits compared to the heat pump.

These results are even more evident if we analyse the cost-benefit cumulative curves together (figure 10). When we assume 1% discount rate, DG provides some benefits compared to the conventional centralised system but no benefits compared to the totally electric solution. By assuming 3% discount rate, DG costs are always higher than centralised costs, both conventional and advanced.

Figure 10 – DG external cost/benefits: cumulative distribution curves



In conclusion, the analysis of the external costs seems to confirm the rather discouraging framework which already emerged from the assessment of the internal costs since DG appears to be low competitive even from the environmental point of view. However, this time, the result is quite surprising, considering that the supposed environmental benefits generally inform the policies designed to support distributed generation. This analysis would thus support the idea that such environmental policies are ambiguous since, by focusing on global warming, they disregard the possible trade-off between local-regional and global impacts.

5.3. 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 models and consequently the DG social benefits. For the sake of simplicity, we do not present the results in terms of the density distribution illustrated above and only report their best guess (table 4).

Total costs fully confirm the unfavourable outcome for distributed generation. Looking at the best guess values, DG total costs are lower than those of large power supply only in the case of gas turbine in Milan with 1% discount rate, and compared to the conventional centralised system. However, even in these cases, cost saving does not exceed 3%.

Table 4 – Social costs and benefits (best guess): "isolated" residential applications

	Centralised systems		Decentralised systems					
	A	B	D1	D1/A	D1/B	D2	D2/A	D2/B
	(kUSD)	(kUSD)	(kUSD)			(kUSD)		
MILANO								
Internal								
(r = 1%)	217.5	198.1	206.4	0.95	1.04	209.6	0.96	1.06
(r = 3%)	222.1	204.0	214.6	0.97	1.05	217.9	0.98	1.07
External								
(r = 1%)	59.5	49.8	68.7	1.15	1.38	58.9	0.99	1.18
(r = 3%)	25.8	22.0	46.0	1.78	2.09	32.9	1.28	1.50
Total								
(r = 1%)	277.0	247.9	275.1	0.99	1.11	268.5	0.97	1.08
(r = 3%)	247.9	226.0	260.6	1.05	1.15	250.8	1.01	1.11
PALERMO								
Internal								
(r = 1%)	195.9	183.2	209.7	1.07	1.14	214.3	1.09	1.17
(r = 3%)	200.5	189.1	218.8	1.09	1.16	223.5	1.11	1.18
External								
(r = 1%)	46.5	41.7	46.8	1.01	1.12	45.7	0.98	1.10
(r = 3%)	19.9	17.8	27.2	1.37	1.53	22.8	1.15	1.28
Total								
(r = 1%)	242.4	224.9	256.5	1.06	1.14	260.0	1.07	1.16
(r = 3%)	220.4	206.9	246.0	1.12	1.19	246.3	1.12	1.19

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

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. This sensitivity analysis will also help us find the overall range of social DG competitiveness.

5.4. Sensitivity analysis

■ 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 useful in pointing out how DG could improve in the near future.

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

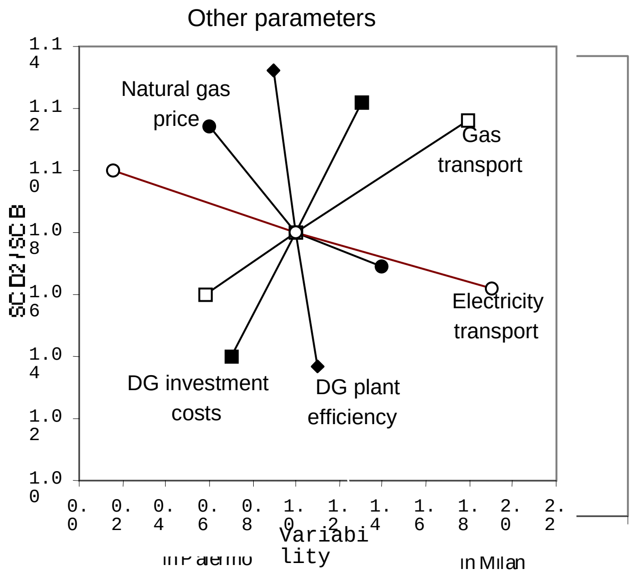
For the sake of simplicity, and without loss of generality, we restrict our investigation to the gas turbine in Milan (D2), which is the best DG solution from social benefits point of view.

□ **Structural conditions (climate)**. 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 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). Figure 11 shows the result of this swap: switching from the base to the worst case implies a considerable decrease in DG benefits whereas switching from the base to the best case implies only marginal improvements so that the ratio of costs is still higher than one.

□ **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 twenty years. By using this range we obtain the sensitivity shown in figure 11. As we can see, DG benefits are so low sensitive to natural gas price variability that it cannot be considered a crucial factor of DG social competitiveness.

□ **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 agree with those who do not expect reductions higher that 30% in the near future. Regarding net plant efficiency, engineers predict only marginal improvements in the next few years, so that +/- 10% seems a plausible range. In the two cases of plant efficiency and investments costs, we also report the lower and upper boundaries in order to take into account current possible overestimation of DG performance. As figure 11 shows, DG benefits are low sensitivity to investment costs and high sensitivity to plant efficiency. The latter therefore appears to be the crucial parameter of DG social competitiveness even though the best case (+10%) again falls above the competitiveness threshold (before considering transaction costs).

Figure 11 – Sensitivity analysis

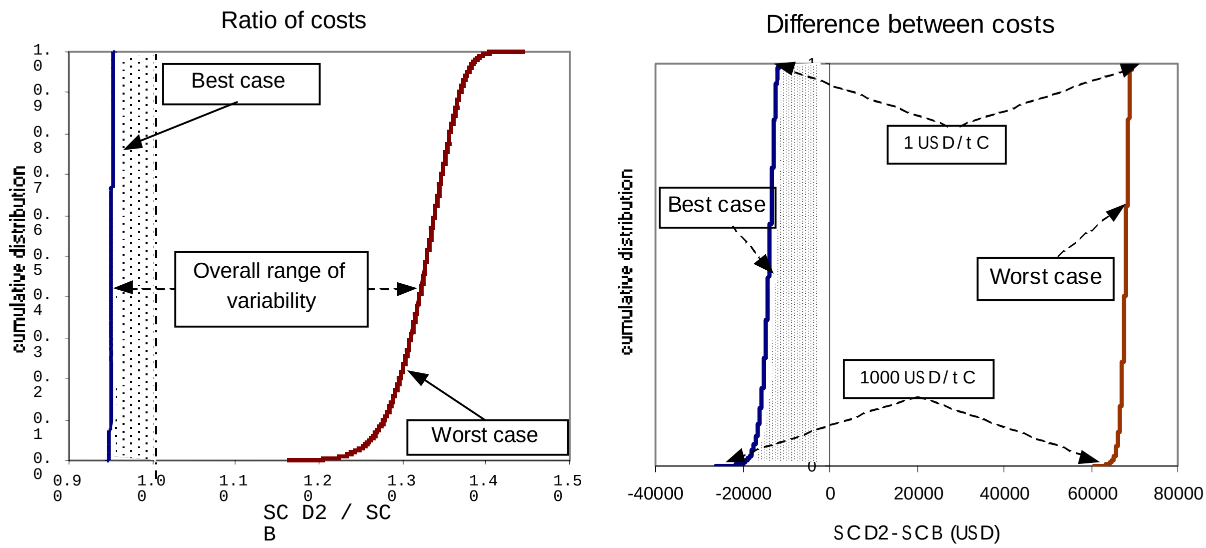


□ **Transport network congestion.** Electricity and gas transport costs utilised in the base case are average values. Therefore they do not take into account the possible effect of grid congestion. Indeed, we are not sure that such effects should be included in this analysis. In fact, in an "ideal" framework congestion would not occur because generating and transport capacity would be optimally expanded without significant divergences over time and/or over "space" (see paragraph 2 above). However, 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. Gas transport price ranges from a minimum of 1.85 to a maximum of 5.69 USD/m^3 per day (–42 ÷ 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[20]: from 14.0 to 16.7 USD/kW (-84 ÷ 90% of the base case value). Figure 11 shows that DG benefits are very low sensitive to both natural gas and electricity transport costs.

[20] See National Grid (2002).

□ **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 negative 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, etc.) or unfavourable (i.e. low natural gas price, high DG investment costs and so on) to DG deployment. These two extreme cases in fact identify by far the best and worst case of DG social competitiveness. Figure 12 shows the outcome of this effort. The results are presented in terms of cumulative distributions in order to keep the uncertainty regarding the external cost estimations. The first observation concerns curve shapes that are almost vertical thus reconfirming that uncertainty has a very low impact on DG benefits. This allows us to clearly identify the social value of distributed generation and to be certain of the effectiveness of the social cost-benefit analysis implemented here. In fact, figure 12 provides an indisputable picture since the range of positive values of DG benefits (ratio of costs lower than one) are very restricted. As we can see, an extremely low increase in transaction costs (around 5%) would be sufficient to totally cancel the DG competitiveness area. This negative outcome occurs even if we measure DG social value in terms of difference between costs (DG social costs minus centralised system costs). This range of competitiveness is again very limited and is very low sensitive to the value of marginal cost of carbon dioxide emissions (the result is almost the same, ranging from 1 USD to 1000 USD per tonne of carbon emitted). This again underlines the scant importance of uncertainty in determining DG social value.

Figure 12 – Overall range of DG social competitiveness



6. Hybrid models: results

■ The result of the analysis described in the preceding paragraph has two policy implications. On the one hand, it means that eliminating possible technical and economic barriers would not be sufficient to promote a highly decentralized model of energy supply (providing this is technically feasible). On the other, it suggests avoiding policy measures which tend to push distributed generation to the limit, with a view to gradually replacing centralized production.

Nevertheless, the question of the "paradigm change" is not the only important question. In fact, in addition to verifying whether it is justified to push to the limit, it is important to understand if and to what extent it would be socially justified to develop DG (where to "stop").

This requires analysing the social benefits of supply models in which distributed generation and centralized production co-exist (hybrid models).

This co-existence can occur in two ways: by means of the "open" solutions described in paragraph 3 or the "isolated" solutions applied, however, to customers larger than the residential one, in terms of energy consumption.

Table 5 – Social costs and benefits (best guess; per annum; r = 1%)

	Fully Centralised	Hybrid								Fully decentralised			
		"Isolated"				"Open"				"Isolated"			
	B	D1	D1/B	D2	D2/B	C1	C1/B	C2	C2/B	D1	D1/B	D2	D2/B
	(kUSD)	(kUSD)		(kUSD)		(kUSD)		(kUSD)		(kUSD)		(kUSD)	
MILAN													
Residential													
Internal	198.1	-	-	-	-	201.5	*1.02*	213.3	*1.08*	206.4	*1.04*	209.6	*1.06*
External	49.8	-	-	-	-	106.3	*2.13*	78.6	*1.58*	68.7	*1.38*	58.9	*1.18*
Total	247.9	-	-	-	-	307.8	*1.24*	291.9	*1.18*	275.1	*1.11*	268.5	*1.08*
Hospital													
Internal	1817.1	1471.3	*0.81*	1576.1	*0.87*	1571.6	*0.86*	1690.6	*0.93*	-	-	-	-
External	526.6	752.6	*1.43*	646.0	*1.23*	957.1	*1.82*	736.8	*1.40*	-	-	-	-
Total	2343.7	2223.9	*0.95*	2222.1	*0.95*	2528.7	*1.08*	2426.8	*1.04*	-	-	-	-
PALERMO													
Residential													
Internal	183.2	-	-	-	-	224.8	*1.23*	306.2	*1.67*	209.7	*1.14*	214.3	*1.17*
External	41.7	-	-	-	-	60.3	*1.45*	55.3	*1.33*	46.8	*1.12*	45.7	*1.10*
Total	224.9	-	-	-	-	285.1	*1.27*	361.5	*1.61*	256.5	*1.14*	260.0	*1.16*
Hospital													
Internal	1667.8	1503.3	*0.90*	1606.4	*0.96*	1729.0	*1.04*	2087.7	*1.25*	-	-	-	-
External	481.4	534.7	*1.11*	537.0	*1.12*	613.2	*1.27*	573.0	*1.19*	-	-	-	-
Total	2149.2	2038.0	*0.95*	2143.4	*1.00*	2342.2	*1.09*	2660.7	*1.24*	-	-	-	-

Therefore, by following the methodology described in paragraph 4 and applying equations (6) and (20), it is possible to simulate the social costs and benefits of the hybrid solutions (technical and economic data are reported in the Appendix). Table 5 shows the following:

1. The hybrid models based on the "open" solutions imply social costs which are considerably higher than those of the "isolated" solutions. This is due to internal costs but mainly external ones.
2. The hybrid models based on large-size "isolated" solutions (i. e. the hospital) ensure an improvement compared to the fully decentralized ones. However, this improvement, which is due to lower internal costs, is rather limited. At best, saving on total costs (internal plus external) does not exceed 5%.

Moreover, it must be borne in mind that the hybrid solutions involve problems of equity. Since distributed generation is a typical case of bypass or regulated competition it might introduce externalities from one category (product) to other categories of customers (products) and is therefore a potential source of inequity.

The economic literature on this issue confirms this. Curien et. al. (1998) analyse optimal pricing regulation under bypass competition and shows that bypass introduces a negative externality from consumers using bypass to consumers using the local network or, when public transfer are allowed, to taxpayers. However the authors assume there is perfect competition in the bypass market while in our case the bypass a regulated firm provides the bypass (network to network competition).

This is why we have also looked at some contributions on regulated competition. In particular Brauetigam (1984) demonstrates that, under specific conditions when firms are separately regulated, the optimal social mark up on marginal costs is higher in competitive market segments. A better result is obtained when the two firms are regulated as if they were one.

Apart from their specific applications, these contributions highlight an interesting issue. If the technology is a simple bypass, that is, if it is only competitive for a few categories of customers (for example, gross consumers), it reduces the welfare of the other categories. Therefore, its overall (social) impact is uncertain.

In conclusion, the analysis of the hybrid models points out that we are not faced with a "convex" world. The intermediate models have social costs which are much higher than the two extreme (polar) situations if they are the "open" kind or, in any case, lower than the centralized solutions (considering the transaction costs) if they are the "isolated" kind.

7. Why so much interest in distributed generation? The role of the market distortions

■ What emerges from the cost-benefit analysis described does not question the present social value of distributed generation. We are not moving towards a new paradigm of the network energy industry. Large power supply is still preferable to decentralised one both from purely an economic (private) and environmental point of view. Rather the analysis emphasises the benefits of further centralisation through the deployment of the totally electric solution (the heat pump) that emerges as the best option.

Given these results, the following obvious question arises: why are regulators, policymakers and operators so optimistic about DG deployment?

Before answering the question it might be useful to reflect upon the simultaneity of technological change and market reforms. Most authors think that emerging DG economic viability is mainly due to the effect of the energy market reforms. Unbundling of services (e.g. generation, transmission, distribution, and auxiliary services) and, where possible, competition involve price unbundling (over time and space) thus providing a favourable environment for DG investments.

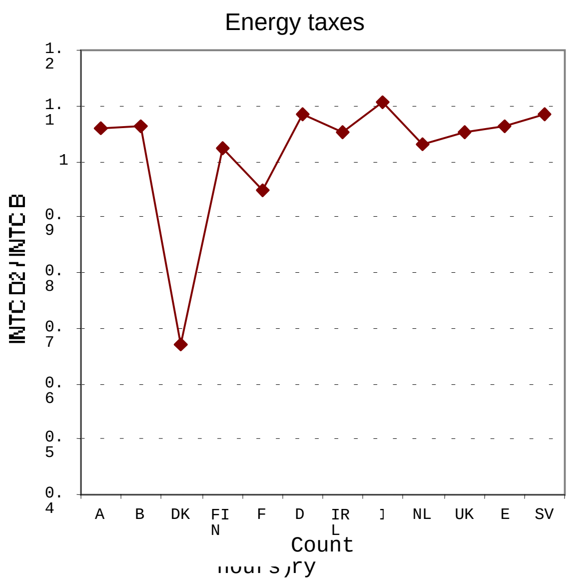
Although this is certainly true in theory, in our opinion, it is not sufficient to legitimise the emphasis on DG development, for two reasons.

First, price unbundling over time (peak/off-peak) can promote DG deployment only when the marginal cost of the small plants is lower than the peak prices of large power supply (including electricity transport). This could, for example, be possible when the centralised peak technology is a large gas turbine (with 32-38% plant efficiency) and the small technology is a reciprocating engine (with 40-42% plant efficiency) and taking the saving in electricity transport costs into account. However, under normal conditions (i.e. absence of capacity scarcity) the margin of competitiveness would be very limited even in this favourable case and probably not sufficient to recover the DG fixed costs.

The situation is quite different when there is market power in the power market or stringent constraints on generation and transport capacity.

Liberalising power generation and creating spot markets are not sufficient conditions to ensure effective competition. Emerging market power might lead to set prices above the marginal costs and this circumstance strongly raises DG profitability. Figure 13 illustrates the importance of this effect. On the horizontal axis we report the Lerner index, which is an indicator of market power, and on the vertical axis the ratio of internal costs (DG costs divided by centralised system costs). As we can see, DG benefits are very high sensitive to market power. If we assume the values of the Lerner index estimated by Borenstein et al. (1999) for the California and PJM markets, DG internal benefits can reach values ranging from 40% to 50%.

Figure 13 – Impact of price inefficiencies



Moreover, market power is not the only potential source of high price volatility. It can also result from emerging capacity scarcity both in generation and transmission segments. In the previous pages we have already pointed out that in this connection market organisations are not indifferent. Since spot markets look at short time horizons, they might be unable to provide adequate price signals to develop capacity in the long run. In other words, spot markets might create structural conditions of over and under capacity thus increasing price volatility. Furthermore, industry vertical unbundling (separation between generation and transmission stages) eliminates explicit investment co-ordination while implicit co-ordination through prices might not be sufficient to ensure a balanced development of generation and transport capacities (both over time and space).

It is therefore undoubtedly true that market reforms can create an environment favourable to DG deployment through industry and price unbundling. However, it is also true that this deployment could be the result of inefficient outcomes, involving too much price volatility in the short and long run, rather than the natural outcome of DG social competitiveness.

Second, our analysis also shows that the positive impact due to unbundling of distribution prices over space is overestimated. In fact it would positively affect DG benefits only if it involved one service (i.e. electricity), the other (natural gas) remaining averaged priced. In this case, competitiveness would increase in those geographic areas where «customer density» is higher (extra-urban area). However, if this unbundling concerned both inputs (electricity and gas) there would be no significant changes in DG economic viability. "Spatial" marginal costs of electricity and gas distribution are in fact supplementary. Increasing the electricity prices in extra-urban areas raises DG benefits. Nevertheless, these benefits would be partially compensated by increasing gas distribution prices and vice-versa in the urban areas.

The problem of price combined effect helps us to introduce the other two potential sources of distortions: inefficient pricing regulation and energy taxation.

Contrary to what we assume in this paper (no source of allocative efficiency), in the real world prices might not reflect marginal costs of supply, and taxes rarely reflect external marginal costs. This can favour or penalise distributed generation depending on the kind of distortion.

As regards price regulation, tariff structures could play an important role. For instance, electricity two-part tariffs with high weight of the variable component (beyond the optimal proportion) raise DG profitability and vice-versa in the case of gas distribution tariff. By simulating the best (electricity tariff totally variable and gas tariff totally fixed) and worst cases (electricity tariff totally fixed and gas tariff totally variable), it is possible to demonstrate DG internal benefits ranging from –8% to 4%.

As regards energy taxes, they obviously influence DG economic viability. High excise taxes on electricity end-use, combined with low taxes on natural gas (for residential uses), increases DG competitiveness and vice-versa in the opposite case. In this connection, it is interesting to simulate what could happen in each European country. As figure 13 shows, Denmark is the only country where energy taxation can considerably modify DG benefits because of the extremely high excise tax on electricity compared to the tax on natural gas.

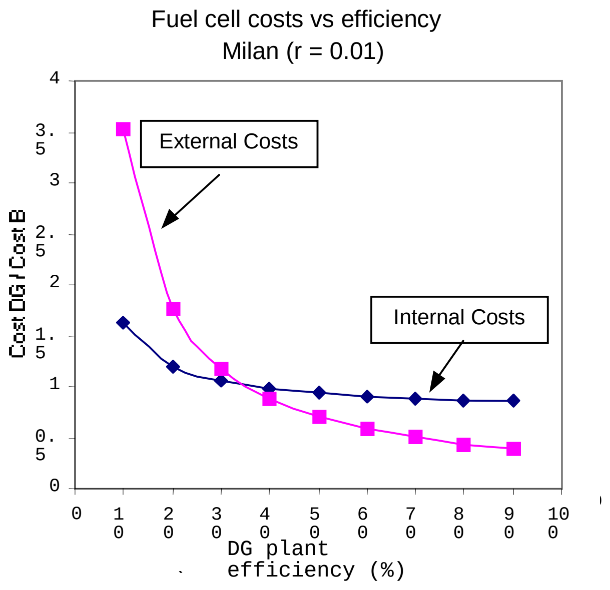
In conclusion, the framework described above supports the idea that the current enthusiasm over distributed generation deployment is due to price inefficiencies. By unbundling services and prices, market reforms can potentially increase DG private competitiveness. Nevertheless, in addition to other price inefficiencies, they can also introduce more serious sources of distortions that can push DG deployment beyond the point legitimised by its real social value.

8. The role of incoming technological innovation: what can fuel cells hold for us in the near future?

■ Our analysis has focused on conventional small technologies (gas engine and gas turbine) and offers a rather discouraging scenario for future DG development. In order to give a definitive answer to the topical question posed in this paper, we need to reflect on what technological change holds for us in the next few years. This compels us to analyse the specific case of the fuel cells. The physical-chemical principle of fuel-cell operation is totally different from that of DG conventional technologies. By means of the fuel cells, the chemical energy of the fuel is directly converted into electricity without the intermediate step of thermal energy generation. This makes it possible to achieve very high efficiency (in theory up to 80%) with a very low environmental impact (see table A2 of the Appendix).

Figure 14 shows the overall range of social competitiveness of the fuel cells. This range was obtained by comparing fuel cells to the heat pump in Milan and assuming that a large power plant (CCGT) with 60% efficiency[21] generates electricity for the centralised solution. Furthermore, as capital costs represent the weak point of the fuel cells, we calculate their overall performance for various levels of unit investment cost. Figure 14 shows a very surprising result. Even if we assumed the same investment cost of the conventional technologies (around 500 USD/kW) the range of social competitiveness would be quite limited. At best, might not exceed 20%. What is the reason of this counterintuitive result?

Figure 14 – Fuel cells



[21] We use 60% efficiency instead of 51% in order to take into account large power plant improvements in the long term.

We attempt to answer this question by separately analysing internal and external cost sensitivities to the plant efficiency variability. As we can see from Figure 14, up to a value of efficiency around 30-40% (which is the typical range of efficiency of the conventional small technologies), sensitivity is relatively high. Beyond this threshold, the marginal improvements due to efficiency increase become considerably lower.

9. Conclusions

■ This paper has attempted to measure the social value of distributed generation by comparing decentralised solutions to large power supply. Despite the great uncertainty regarding external cost estimations, the paper clearly demonstrates 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. This overall result has allowed us to clearly answer the topical question this paper posed. In fact, it clearly emerges that we are not moving towards a new paradigm of the network energy industry, based on a wide decentralisation of energy supply, both in the short (conventional DG technologies) and in the long term (fuel cells).

Given this unfavourable framework, we have tried to understand why operators, regulators and legislators are so optimistic about DG development. Answering this question has required enlarging our perspective by analysing the importance of market distortions and supporting environmental policies.

Market power in power market, as well as inefficient price regulation and energy taxation, can play a fundamental role in raising DG profitability beyond its real social value. In this sense, DG deployment could be the sign of the failure of the energy market reforms and support the idea that the traditional organisational model, based upon vertically and horizontally large firms and hierarchic transactions, is still the industry social paradigm.

At the same time, too much emphasis on global environmental effects, and consequently on the extent of energy saving, can distort the perception of the real environmental value of distributed generation. This leads us to carefully reflect upon the potential ambiguity of environmental policies which focus too much on reducing CO_2 emissions and thus disregard the possible trade-off between local-regional and global effects.

In conclusion, one needs to be prudent in supporting DG deployment. Small distributed plants might be useful in mitigating market power, increasing system reliability 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, DG is only the third best solution. Removing technical and economic barriers is welcomed but providing subsides must be carefully evaluated.

Appendix

■ This appendix includes two sections. The first describes the technical data used in this paper. The second describes the methodology set out to evaluate long-run marginal costs of electricity and gas supplies.

□ **Basic data**. This part of the appendix describes the technical and economic data used in this paper. Tables from A1 to A6 report the value of the technical parameters and the unit investment costs. Table A7 reports the value of the electricity and gas tariff components. All components, both fixed and variables, refer to average values in Italy calculated by elaborating data and information provided by the Italian Energy Authority[22] (Autorita' per l'Energia Elettrica e il gas – AEEG). Finally concerning $\Phi_k(H_k)$ the following functions, typical of the Italian market, have been adopted:

$\Phi_e(H) = 1 - e^{-0,00052 \cdot H}$ for electricity and $\Phi_g(H) = 1 - e^{-0,0016 \cdot H}$ for natural gas

Table A1 – 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

Table A2 – Power technologies: electrical efficiency and emission rate

	Efficiency	Emission rate(1)			
		CO_{2eq}	SO_x	NO_x	PM_{10}
	%	(g/kWh)	(g/MWh)	(g/MWh)	(g/MWh)
Gas engine	40	452.8	2.5	897.8	12.3
Gas turbine	30	611.0	2.5	469.3	32.4
Fuel cell (MCFC)	54	371.0	2.4	16.1	0.0
CCGT	51	352.3	1.8	27.3	18.2

(1)Per unit of electricity generated
Sources: European Commission (1997b); Regulatory Assistance Project (2001)

[22] See Autorità per l'Energia Elettrica e il Gas (1999, 2000, 2001, 2002)

Table A3 – Applications: plant sizes

		A	B	C1	C2	D1	D2
		Residential building in Milan					
	Plant typology	CB+CR	HP	CHP + AR		CHP+HP+AR	
Plant size	Power generation (CHP)			1200	1035	661	619
(kW)	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					
Plant size	Power generation (CHP)			8547	7364	4753	4439
(kW)	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 size	Power generation (CHP)			1315	1136	710	664
(kW)	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					
Plant size	Power generation (CHP)						
(kW)	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 centralised peak generation).
Source: Bruzzi (2002)

Tab. A4 – Investment costs(1) (USD 01/kW)

	Residential						Hospital					
	A	B	C1	C2	D1	D2	A	B	C1	C2	D1	D2
CB	23						14					
CR	280						230					
HP		370			370	370		320			320	320
AR			200	200	200	200			137	137	137	137
CHP			460	500	460	500			410	460	410	460
TG						270						

(1) Per unit of output; Note: TG: large turbine gas (for centralised peak generation).

Table A5. Technical parameters and investment costs (residential building)

	Centralised systems				Decentralised systems							
					"Open"				"Isolated"			
	A		B		C1		C2		D1		D2	
	Milan	Palermo	Milan	Palermo	Milan	Palermo	Milan	Palermo	Milan	Palermo	Milan	Palermo
Consumption												
E_g (m^3)	263,629	120,400	45,867	45,867	1,014,800	811,736	984,987	816,322	405,503	351,922	458,562	403,939
E_e (MWh)	1417	1542	1945	1648					0	0	0	0
E_e^{Gnet} (MWh)	-	-	-	-	-3107	-2328	-2332	-1799	0	0	0	0
Sizing												
P_g (m^3/d)	2945	1828	125	125	7503	8226	7848	8611	4133	4439	3870	4152
P_e (kW)	840	1031	858	1031	-	-	-		-	-	-	-
Investment costs												
IC (kUSD)	391	416	493	530	811	889	782	859	728	816	732	792
Natural gas												
H_g (hours)	2148	1581	8760	8760	3246	2368	3012	2275	2355	1903	2844	2335
$\Phi_g(H_g)$	0.915	0.838	1	1	0.976	0.934	0.969	0.927	0.933	0.888	0.962	0.932
Electricity												
H_e (hours)	1687	1496	2267	1599	-	-	-	-	-	-	-	-
$\Phi_e(H_e)$	0.584	0.541	0.692	0.565	-	-	-	-	-	-	-	-
Large power generation												
$\Phi_{gG}(H_{gG})$	1	1	1	1	-	-	-	-	-	-	-	-

Table A6 – Technical parameters and investment costs (hospital)

	Centralised systems				Decentralised systems							
					"Open"				"Isolated"			
	A		B		C1		C2		D1		D2	
	Milan	Palermo	Milan	Palermo	Milan	Palermo	Milan	Palermo	Milan	Palermo	Milan	Palermo
Consumption												
E_g (m^3)	2,023,762	1,113,101	417,804	45,867	7,588,848	6,344,298	7,349,195	6,326,681	4,440,519	4,165,006	5,027,612	4,749,598
E_e (MWh)	17,708	18,615	21,562	19,604	-	-	-	-	0	0	0	0
E_e^{Gnet} (MWh)	-	-	-	-	-16,008	-11,240	-10,091	-6924	0	0	0	0
Sizing												
P_g (m^3/d)	21,100	11,834	1148	1148	53,456	58,552	55,831	61,195	29,718	31,863	27,755	29,787
P_e (kW)	5550	6847	6116	6847	-	-	-	-	-	-	-	-
Investment costs												
IC (kUSD)	2311	2982	3297	3292	4740	5238	4626	5076	4413	4777	4432	4799
Natural gas												
H_g (hours)	2464	1581	8760	8760	3407	2600	3012	2481	3586	3030	4347	3407
$\Phi_g(H_g)$	0.941	0.838	1	1	0.980	0.950	0.969	0.942	0.984	0.969	0.993	0.980
Electricity												
H_e (hours)	3191	1496	3256	1599	-	-	-	-	-	-	-	-
$\Phi_e(H_e)$	0.810	0.541	0.840	0.565	-	-	-	-	-	-	-	-
Large power generation												
$\Phi_{gG}(H_{gG})$	1	1	1	1	-	-	-	-	-	-	-	-

Table A7 – Other economic parameters

	Centralised systems				Decentralised systems							
	A		B		C1		C2		D1		D2	
	Milan	Palermo	Milan	Palermo	Milan	Palermo	Milan	Palermo	Milan	Palermo	Milan	Palermo
Natural gas												
c_g = 122.9 mUSD/ m^3 ; μ_{gsm} = 13.7 mUSD/m^3; δ_{gsm} = 3844.4 mUSD/m^3/d; μ_{gT} = 5.4 mUSD/m^3; δ_{gT} = 3174.7 mUSD/m^3/d; μ_{gD} = 0 mUSD/m^3; $\overline{\delta}_{gd}$ = 5672.5 mUSD/m^3/d; β =0.069(*)												
Residential building												
δ_{gsp} (mUSD/ m^3/d)	1849.1	2979.0	22,706.8	22,706.8	1287.4	1255.7	1345.3	1307.9	1583.3	1537.9	1628.1	2236.2
Hospital												
δ_{gsp} (mUSD/ m^3/d)	1053.6	1154.6	3296.3	3296.3	976.0	971.0	983.7	978.5	1016.1	1010.0	1022.6	1015.9
Electricity												
δ_{eG} = 30 USD/kW; μ_{eT} = 0.95 mUSD/kWh; δ_{eT} = 8462.9 mUSD/kW); μ_{eD} = 5.0 mUSD/kWh; $\overline{\delta}_{eD_{MV}}$ = 18,8023.8 mUSD/kW; $\overline{\delta}_{eD_{LV}}$ = 13,220.5 mUSD/kW												
Residential building												
δ_{esp} (mUSD/kW)	7298.4	5946.3	7221.8	5946.3	-	-	-	-	-	-	-	-
δ^{*}_{e} (USD/kW)	-	-	-	-	-	-	-	-	22.5	18.3	22.5	18.3
δ^{**}_{e} (USD/kW)	-	-	-	-	10.9	10.8	11.0	11.0	-	-	-	
Hospital												
δ_{esp} (mUSD/kW)	4201.4	4096.8	4150.3	4096.8	-	-	-	-	-	-	-	-
δ^{**}_{e} (USD/kW)					6.5	5.9	7.1	6.7	6.0	5.8	6.2	6.0

(*) Incidence of working gas (gas storage)

□ **Long run marginal costs**. The demand for public utility service varies not only periodically over the month and year, but also varies significantly on a daily or weekly basis. Public utilities have been concerned for nearly a century with this peaking demand. The problem of meeting these variations in load with some optimum sized plant capacity and the accompanying investments and costs, all in the framework of a pricing structure, is called the peak load pricing problem.

In this appendix we propose an alternative methodology for dealing with the problem of the peak load pricing. Instead of resolving the problem of consumer's surplus we directly calculate the long run marginal cost of delivering a new customer. For this purpose we proceed as follows.

Suppose an utility faces a capacity demand curve $P(H)$ which describes the classical monotone curve with H the number of hours of the year in which the capacity demand is higher then P. Let $c_i(H) = f_i + v_i H$ be the annual cost of deliver a unit of capacity and Γ_1, Γ_2 and Γ_3 the best available technologies with $f_1 < f_2 < f_3$ and $v_1 > v_2 > v_3$. From figure A1 it follows that the minimum cost C of covering $P(H)$ will be:

(A1)
$$C = f_3 \cdot P_3 + v_3 \cdot \left[P_3 \cdot H_2 + \int_{H_2}^{H_3} P(H)dH \right] + f_2 \cdot (P_2 - P_3) + v_2 \cdot \left[(P_2 - P_3) \cdot H_1 + \int_{H_1}^{H_2} P(H)dH - P_3 \cdot (H_2 - H_1) \right] +$$
$$+ f_1 \cdot (P_1 - P_2) + v_1 \cdot \left[\int_{H_0}^{H_1} P(H)dH - P_2 \cdot H_1 \right]$$

Assume now that the utility supplies a new customer with a demand profile $\Delta P(H) = \overline{P}(H) - P(H)$ where $\overline{P}(H)$ is the new monotone curve. From figure A1 it follows that the minimum cost of covering $\overline{P}(H)$ will be

(A2)
$$C_1 = f_3 \cdot (P_3 + \Delta P_3) + v_3 \cdot \left[(P_3 + \Delta P_3) \cdot H_2 + \int_{H_2}^{H_3} \overline{P}(H)dH \right] + f_2 \cdot (P_2 + \Delta P_2 - P_3 - \Delta P_3) +$$
$$+ v_2 \cdot \left[(P_2 + \Delta P_2 - P_3 - \Delta P_3) \cdot H_1 + \int_{H_1}^{H_2} \overline{P}(H)dH - (P_3 + \Delta P_3) \cdot (H_2 - H_1) \right] + f_1 \cdot (P_1 + \Delta P_1 - P_2 - \Delta P_2) +$$
$$+ v_1 \cdot \left[\int_{H_0}^{H_1} \overline{P}(H)dH - (P_2 + \Delta P_2) \cdot H_1 \right]$$

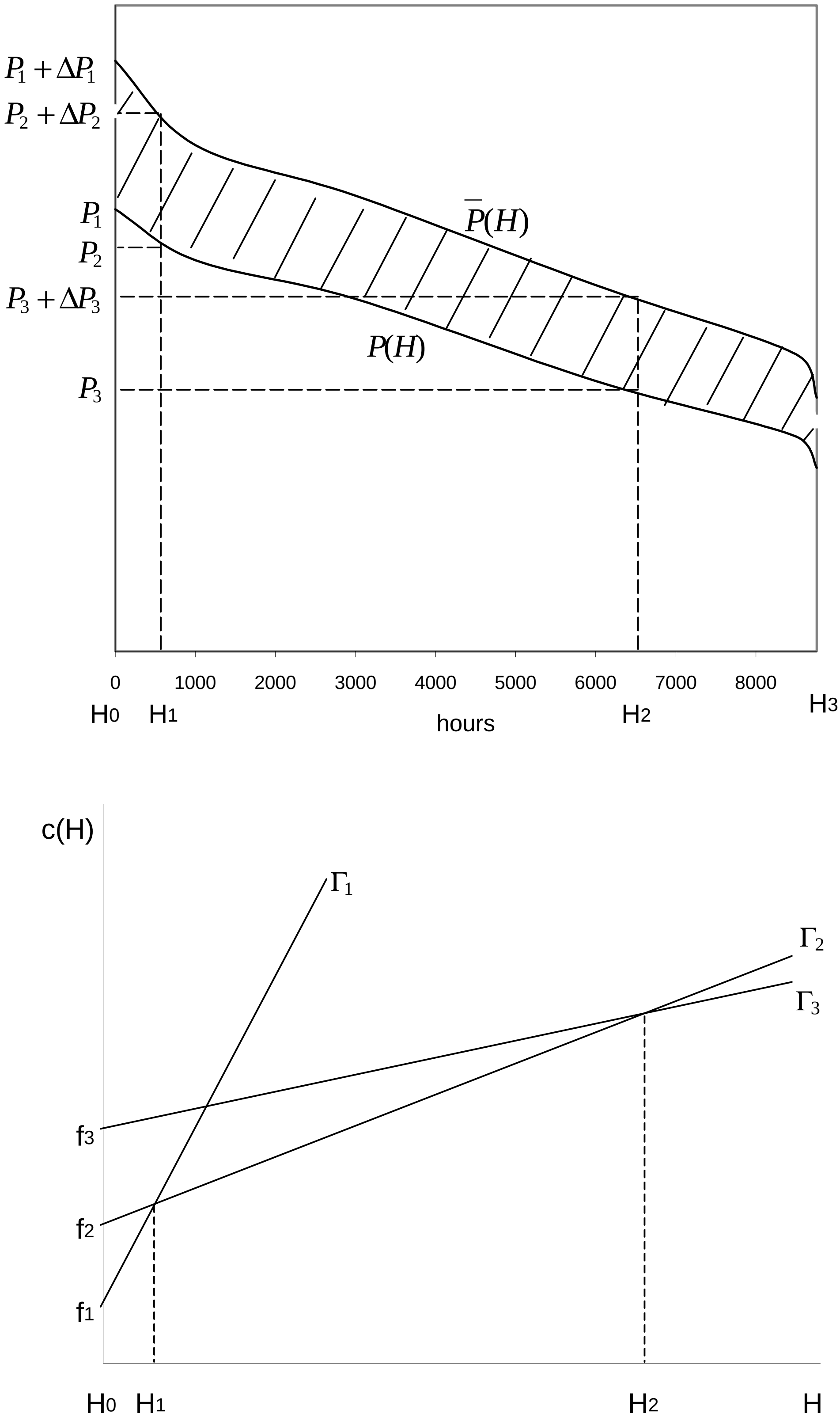
Given equations A1 and A2 and the marginal cost will be:

(A3)
$$\Delta C = C_1 - C_0 = \Delta P_3 \cdot (f_3 - f_2) + \Delta P_2 \cdot (f_2 - f_1) + \Delta P_1 \cdot f_1 + \Delta P_3 \cdot H_2 \cdot (v_3 - v_2) + \Delta P_2 \cdot H_1 \cdot (v_2 - v_1) +$$
$$+ v_1 \cdot \int_{H_0}^{H_1} \Delta P(H)dH + v_2 \cdot \int_{H_1}^{H_2} \Delta P(H)dH + v_3 \cdot \int_{H_2}^{H_3} \Delta P(H)dH$$

Now, as $H_1 = (f_2 - f_1)/(v_1 - v_2)$, $H_2 = (f_3 - f_2)/(v_2 - v_3)$ and $\Delta P(H) = \overline{P}(H) - P(H)$, for the case of n technologies we have:

(A4)
$$\Delta C = f_1 \cdot \Delta P_1 + \sum_{i=1}^{n} v_i \cdot \int_{H_{i-1}}^{H_i} \Delta P(H)dH$$

Figure A1 – Load monotone curve and technology costs



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