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ScienceDirect

Energy Procedia 101 (2016) 240 – 248

Energy Procedia

71st Conference of the Italian Thermal Machines Engineering Association, ATI2016, 14-16 September 2016, Turin, Italy

Introducing solar thermal "net metering" in an actual small-scale district heating system: a case-study analysis

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Abstract

An energy and economic analysis on an hypothesis of introduction of prosumers in an actual small-scale district heating system (DHS) in Northern Italy has been carried out. The study was performed by means of dynamic simulations of the DHS. The investigated configurations include the transformation of one or more customers in prosumers, producing and self-consuming solar thermal heat, and supplying the DHS with the excess heat produced. For the considered case-study the solar heat fed into the DHS is basically antagonist of the CHP production. This leads to a decrease in the non-renewable energy share for the whole DHS, to a decrease in the profit of the DHS utility and to a profitable investment for the prosumers.

Peer-review under responsibility of the Scientific Committee of ATI 2016.

Keywords: District heating, Solar thermal heat, Distributed generation, Net metering, Prosumers.

1. Introduction

Requirements regarding the share of heat demand for domestic hot water, heating and cooling provided by renewable sources are becoming in Europe more and more ambitious. The Italian regulation on energy efficiency, as a consequence of the transposition of the European Directive 2009/28/CE will require, from January 2017, a renewable energy share, for new buildings or for buildings subjected to a deep renovation, of at least 50%. District Heating Systems (DHS) connected to distributed solar collectors are infrastructures that could contribute in reaching

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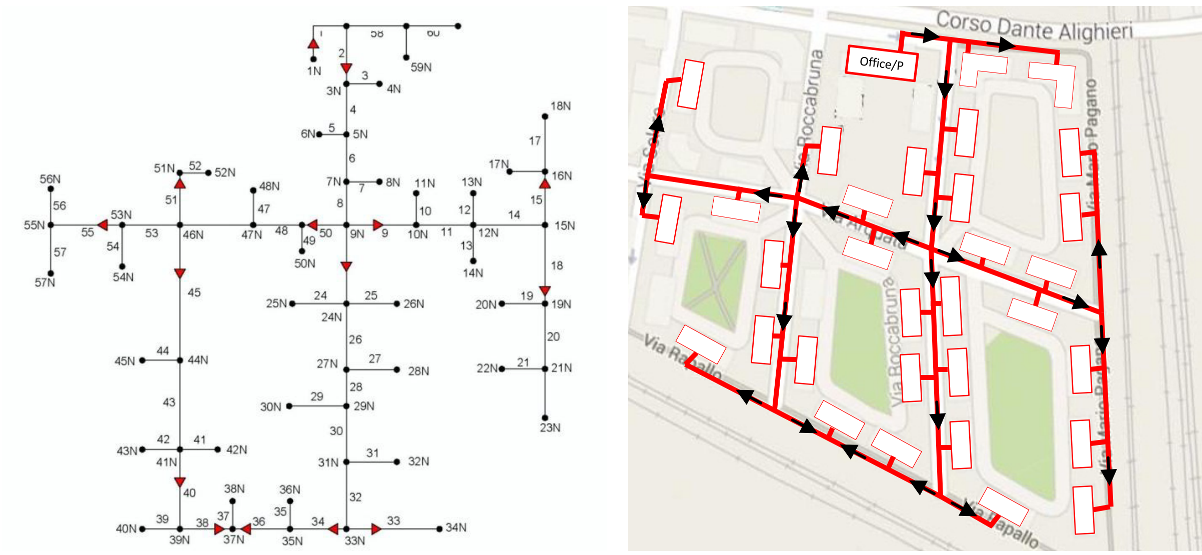
Peer-review under responsibility of the Scientific Committee of ATI 2016.
doi:10.1016/j.egypro.2016.11.031

this target and, especially in urban and densely built areas, could contribute to solve the possible technical constraints where the installation of technologies to produce the required heat demand from renewable sources might be difficult due to lack of space or for integration problems. In this paper the renewable energy share for the buildings connected to a DHS is thought to be provided by means of the transformation of one or more buildings from customers to prosumers thanks to the installation of solar collectors on the roofs. The prosumers are thought to be connected to the DHS with a “thermal net metering” management, which can be defined as a mechanism that allows renewable energy producers to use the district heating network as a thermal storage for the energy produced and not self-consumed, gathering the definition used for power grids. The DHS utility, on the other hand, can distribute to the whole system the solar energy fed in by the prosumers. In this scenario, the energy and environmental benefit represented by a DHS can be further enhanced with the concept of Smart District Heating (SDH). A smart district heating system replies, in the heating sector, the concept of distributed generation and of energy exchange between a prosumer and the grid, already known for the electrical sector.

2. Methods

To evaluate the introduction in an existing DHS of one or more prosumers with solar fields installed on the available building roofs, a numerical tool, described in [1], was used. A small-scale DHS located in the Municipality of Torino (Northern Italy) was simulated.

2.1. The Analyzed Small-Scale District Heating System



(b)

(a)

Figure 1. Scheme of the DHS. (a) Supply scheme, nodes and pipes; (b) Supply scheme, gas boiler heat plant, supplied buildings.

The analysed DHS consists of 31 residential buildings for approx. 38’200 m^2 heated, plus the office building of the DHS utility, which is directly supplied by the heat plant and not by the DHS itself. The heat plant, placed in the office building’s basement, consists of 1 gas engine combined heat and power unit (CHP) of 970 kW_{EL} and 1160 kW_{TH}, 1 condensing gas boilers of 895 kW_{TH}, 1 gas boiler of 2’600 kW_{TH}, and 1 emergency gas boiler of 2’600 kW_{TH}. The energy thermal loads of the buildings have been assessed by means of dynamic simulations, whereas the thermal and electric loads of the office building were given by the DHS utility [2] and [3].

The set-points of the working feeding temperature during winter and summer are, respectively, 75±2°C and 65±2°C. The total extension of the DHS is approx. 4000 m. A scheme of the system is shown in Fig. 1. Further details on the analyzed DHS can be found in [4], [5] and [6].

2.2. The Simulated Layouts

In the investigated "net metering" connection mode, the prosumer can use the DHS as a virtual storage for the thermal energy produced and not immediately used, with the possibility to use it later, although by paying the utility for the storage service. Figure 2 shows the scheme of the modeled bidirectional substation of a prosumer connected to the DHS. The solar system is connected directly to a local thermal storage, which is part of the bidirectional system itself: it preheats the operating temperature during the heating season and it risks, eventually, to overheat the water during the summer season. The local thermal storage, together with the heat exchanger, is the connection between the prosumer and the DHS: it collects the heat fluxes from the solar plants which supply the substation, and from the DHS, and it delivers the heat loads to the supplied building or to the DHS. For the present case-study, the simulated scheme of bidirectional substation is designed to introduce into the distribution network only the excess of thermal energy produced by the solar thermal collectors and not directly self-used to satisfy the building's heat loads. The operating principle of the bidirectional thermal exchange is "supply to return" [7] and the energy is fed to the DHS when the temperature of the thermal storage in the customer substation exceeds the DHS supply temperature of at least 2°C. The regulation strategy of the bi-directional substation is described in [8].

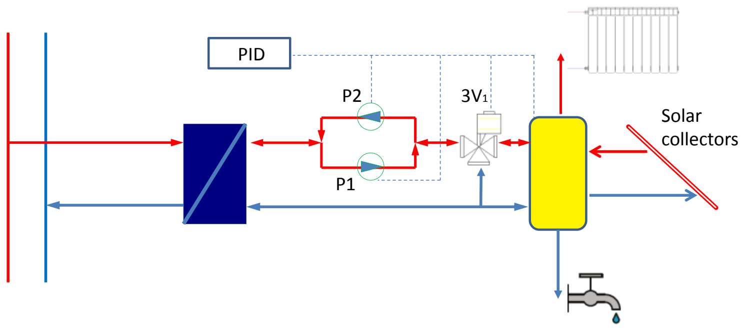


Figure 2. Scheme of the simulated bidirectional substation.

The solar collectors can be potentially installed on the roofs of 19 buildings. On 11 buildings the collectors can be installed with an azimuth of 120°, for a total surface of approx. 1170 m^2, corresponding to a peak power of approx. 2200 kW; on 3 buildings the collectors can be installed with an azimuth of 200°, for a total surface of approx. 260 m^2, corresponding to a peak power of approx. 185 kW; on 1 building the collectors can be installed with an azimuth of 165°, for a total surface of approx. 40 m^2, corresponding to a peak power of approx. 30 kW. The total surface of solar collectors which can be potentially installed is therefore approx. 1470 m^2, corresponding to a peak power of approx. 1050 kW.

The following solar plant layouts were simulated:

- *Layout 0 – Baseline*: the actual DHS without solar plants.
- *Layout 1 – 7% So. – 100% build.* : DHS with installed 7% of the total solar potential, on one single building, corresponding to 100 m^2 and a peak power of 71 kW. This layout corresponds also to 100% of the solar potential on one building with azimuth 200°.
- *Layout 2 – 15% Sol*: DHS with installed 15% of the total potential, on 2 buildings, corresponding to 200 m^2 and a peak power of 143 kW.
- *Layout 3 – 40% Sol*: DHS with installed 40% of the total potential, on 7 buildings, corresponding to 595 m^2 and a peak power of 428 kW.

- *Layout 4 – 60% Sol*: DHS with installed 60% of the total potential, on 10 buildings, corresponding to 894 m^2 and a peak power of 642 kW.
- *Layout 5 – 80% Sol*: DHS with installed 80% of the total potential, on 14 buildings, corresponding to 1170 m^2 and a peak power of 840 kW.
- *Layout 6 – 100% Sol*: DHS with installed 100% of the total potential, corresponding to 1470 m^2 and a peak power of 1055 kW.
- *Layout 7 – 80% build.* : DHS with installed, on one single building, 80% of the solar potential of the building, corresponding to 80 m^2 and a peak power of 57 kW.
- *Layout 8 – 60% build.* : DHS with installed, on one single building, 60% of the solar potential of the building, corresponding to 60 m^2 and a peak power of 43 kW.
- *Layout 9 – 40% build.* : DHS with installed, on one single building, 40% of the solar potential of the building, corresponding to 40 m^2 and a peak power of 29 kW.
- *Layout 10 – 20% build.* : DHS with installed, on one single building, 40% of the solar potential of the building, corresponding to 20 m^2 and a peak power of 14 kW.

In the layouts from 1 to 5 a share of the maximum installable total solar surface was considered, with *Layout 1* corresponding to the maximum installable solar surface on one single building among those with azimuth 200°. The solar collectors were placed on a number of roofs which minimizes the number of solar plants. In the layouts from 7 to 10 a share of the maximum installable solar surface on one single building was considered, with only one single solar plant installed in the DHS.

2.3. Energy Performance Indicators

The characterization of the energy performance of the simulated layouts was performed using mainly the following energy indicators:

- *Non-Renewable Equivalent to Nominal Power Duration (H_{eq_NR})*, defined as [8]:

$$H_{eq\_NR} = \frac{\textit{Thermal Energy Produced from Fossil Fuels}}{\textit{Rated Non-Reneable Heat Plant Thermal Power}} \quad [h] \tag{1}$$

- *Renewable Utilization Factor (UF_R)*, defined as [8]:

$$UF_R = \frac{\textit{Thermal Renewable Energy Produced} - \textit{Increase in Th.Losses}}{\textit{Thermal Renewable Energy Produced}} \quad [-] \tag{2}$$

It indicates the percentage of the total produced renewable energy, reduced by the increase in the energy losses for dispersion introduced in the DHS by energy fed in by the prosumers.

- *Usable Equivalent to Peak Power Duration of Renewables (UH_{eq_R})*, defined as [8]:

$$UH_{eq\_R} = UF_R \cdot H_{eq\_R} \quad [h] \tag{3}$$

Where H_{eq_R} is the equivalent number of operating hours at peak load of the solar plants in a year [8]. This index represents the equivalent number of useful operating hours at peak load of the solar plants in a year, namely the total renewable energy produced, reduced by the increase in losses for dispersion introduced in the DHS by the installation of the solar fields.

2.4. Economic Indicators

The economic performance for a single prosumer (meant as all of the owners of a single building) of the installation of a solar field and its connection to the DHS, with respect to the actual configuration (baseline – simple connection to the DHS) was assessed using the net present value, defined as:

$$NPV(i, N) = \sum_{t=0}^{N} x_t * (1+i)^{-t} - I_0 \qquad (4)$$

Where: t is the year of the cash flow, x_t is the cash flow during the year t (difference between the costs of the baseline layout and the costs of the investigated layout), i is the discount rate, N is the total number of years, I_0 is the total initial investment cost.

The NPV was calculated assuming i = 5%, N = 10 years, considering an average present price for natural gas in Northern Italy (approx. 0.40 €/Sm^3) and an average buying price of the thermal energy provided by DHS in the area of the Municipality of Torino (approx. 0,090 €/kWh). The initial investment cost was assessed considering an average price for evacuated tube collector plants (approx. 555 €/m^2) and an average price for the local thermal storage (approx. 2'500 €/m^3), including piping costs.

The economic performance of the presence of prosumers on the considered DHS for the utility, with respect to the actual configuration (baseline), was assessed using the variation of the earnings before interest, taxes, depreciation and amortization (EBITDA) which is roughly the cash flow, for one year.

Both the economic performance for the prosumer and for the district heating utility were analyzed considering different selling prices of the thermal energy provided by the prosumer to the DHS: 0.045 €/kWh (corresponding to 50% of the average buying price), 0.0225 €/kWh (25% of the buying price) and the limit case of thermal energy provided to the DHS for free, that is 0.000 €/kWh.

3. Results and Discussion

3.1. Energy analysis

Considering the layouts with only one prosumer, that is only one building with installed solar collectors (Table 1), the annual solar heat production ranges from a minimum of 12,5 MWh to a maximum of 61,9 MWh. Approximately 82% of the production is in summer. All the solar heat produced in winter is self-consumed. In summer, part of the production is fed into the DHS, and the remaining part is supplied to the building or lost in local thermal losses. With the minimum installed surface layout (layout 10) the produced heat is substantially self-consumed by the prosumer, and the production is not sufficient to satisfy the summer heat loads (domestic heat water-DHW loads) of the building: only 6.24% of the production is fed into the DHS, and 76.5% of the summer DHW loads are met by solar. An increase in the solar production, with larger solar collectors, increases both the share of solar production fed into the DHS (up to a maximum of 60.77%), and the share of summer DHW loads met by solar energy: at layout 8 the DHW heat load is almost completely met by solar, and further increases of the solar production lead up to a 107% of "self-satisfaction", meaning that the energy produced and not fed into the DHS exceeds the DHW loads with the remaining part lost in thermal losses. The increase in the thermal losses with respect to the baseline depends on the fact that the feed-in takes place only when the temperature in the local heat storage is at least 2°C higher than the DHS supply temperature. The increase in the local thermal losses ranges between +3.32% and +6.39%; in the layouts with larger solar collectors (layout 1, 7 and 8), the increase in the heat losses is almost constant, meaning that the local storage, once met the feed-in temperature, reaches an almost constant temperature [8].

Table 1. Main energy results and energy performance indicators for the single prosumer layouts.

	Baseline	20% Build.	40% Build.	60% Build.	80% Build.	100% Build.
E_Sol_Prod [MWh]	-	12.5	24.9	37.3	49.6	61.9
E_Sol_Prod_sum [MWh]	-	10.3	20.5	30.7	40.9	51.0

E_Sol_to_DHS_sum [MWh]	-	0.8	8.8	18.3	27.9	37.6
Δ E_loss_sum [-]	-	3.32%	5.70%	6.01%	6.27%	6.39%
% E_Sol_to_DHS [-]	-	6.24%	35.50%	49.10%	56.33%	60.77%
Building solar self-satisf. summer [-]	-	76.5%	93.4%	99.4%	103.5%	107.2%

The layouts with solar production on one (layout 1) or more prosumers in the DHS (layouts 2 to 6) show that the solar production substitute, as expected, the thermal production by the thermal plant (Table 2): the maximum annual solar production is 822 MWh, whereas the corresponding decrease in the thermal energy by the plant is 777 MWh, with the difference ended in an increase of thermal losses of approx. 43 MWh. As it already happened in the single building case, in every layout the solar production in winter is completely self-consumed and the feed-in, as well as the increase in the thermal losses takes place in summer. In the considered case study the increase in the summer thermal losses exceed 1% (reaching the maximum of +13.3% for layout 6) only when the solar production exceeds the DHW heat load in summer of the whole DHS (which is approx. 388 MWh) and this happens layouts 1, 7 and 8; in any case this increase is little with respect to the total annual energy fed into the DHS: the incidence of the thermal losses on the overall annual energy of the DHS ranges from 9.75% of the baseline to 10.27% with the maximum solar production, with a maximum increase of the incidence of the losses of approx. 0.52%. It must be noted that the maximum solar energy production in summer is lower than the sum of the DHW heat loads and of the heat losses in the baseline.

Table 2. Main energy results for the different multiple prosumers layouts

	Baseline	7%	15%	40%	60%	80%	100%
E_Sol_Prod [MWh]	-	61.9	123.9	340.1	515.0	675.6	821.9
Eth_Plant [MWh]	7'321.6	7'260.7	7'199.6	6'987.5	6'821.0	6'669.7	6'545.0
E_loss_TOT_sum [MWh]	321.5	321.6	321.7	323.8	330.6	340.2	364.2
Efuel_CHP_sum [MWh]	1'001.5	920.0	838.7	545.2	355.4	239.4	129.9
Eel_CHP_sum [MWhe]	361.3	331.9	302.6	196.8	128.3	86.4	46.9
Δ E_loss_TOT_sum [-]	-	0.0%	0.1%	0.7%	2.8%	5.8%	13.3%
E_loss_incidence [-]	9.75%	9.76%	9.76%	9.77%	9.86%	9.97%	10.27%
% E_Sol_to_DHS [-]	-	60.79%	60.77%	59.54%	58.73%	56.15%	51.94%
Solar Fraction [-]	-	0.85%	1.69%	4.64%	7.02%	9.20%	11.16%

Some losses are present anyway, and they are strictly related to the increase, due to the feed-in by the prosumers, in the supply temperature of the DHS. Figure 3 shows that for the layouts 1, 9 and 10 the supply temperature of the DHS is not substantially influenced by the prosumers. In the remaining layouts the supply temperature increases, with two consequences: an increase in the thermal losses and a decrease in the ability of the prosumers to feed-in their excess of energy, since the supply DHS temperature is the reference temperature for the feed-in. The share of produced solar energy fed into the net (% E_Sol_to_DHS) decreases from 60.79% with the minimum solar production to 51.94% with maximum production with an appreciable decrease the last two layouts. As far as the solar fraction is concerned, it ranges from 0.85% with only one prosumer, to 11.16% with the maximum installation of solar plants.

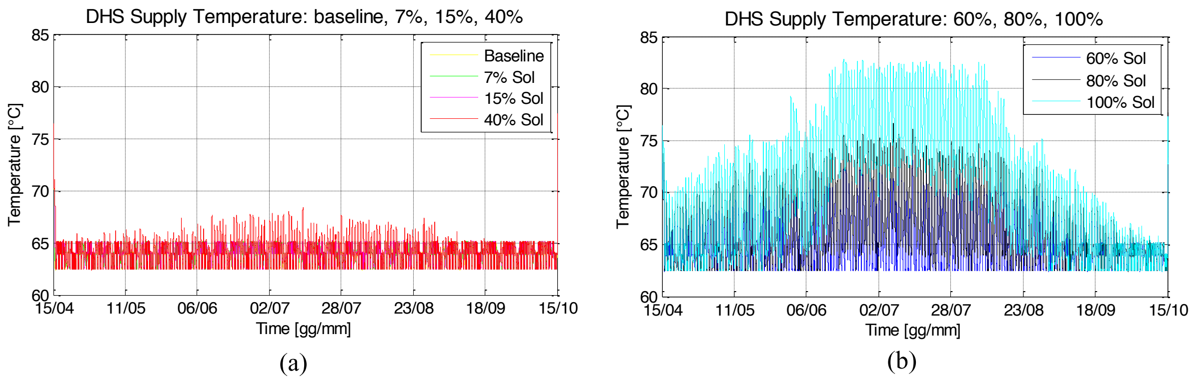


Figure 3. DHS Supply temperature for different solar plant layouts.

The substitution of part of the DHS energy from non-renewable sources with solar energy is shown by the equivalent number of operating hours at full load of fossil fuel generators (H_{eq_NR}), which decreases from 1551 to 1404 (Table 3) while the number of useful operating hours at peak load of the solar plants (UH_{eq_R}) has its maximum value with the minimum solar production, and it decreases with larger solar fields for the already discussed feed-in temperature issue. For the configuration of the present case-study, where the summer CHP thermal production was enough to meet the summer heat loads of the whole DHS, the introduction of solar heat is in direct competition with the CHP: the primary energy for the CHP in summer goes down from approx. 1000 MWh in the baseline to approx. 130 MWh for the maximum solar production layout, with a reduction of 87% that corresponds also to the maximum reduction of the electric energy produced by the CHP unit in summer. This reduction in the electricity produced in summer (-314 MWhe) is particularly important in the considered case-study: the electric self-consumption in summer is, for the baseline layout, approx. 213 MWhe (mainly related to the office building) and if on one hand the introduction of the solar heat reduces the non-renewable share of the DHS thermal energy, on the other it cancels completely the production of electric energy that will be consumed (and therefore produced) in any case.

Table 3. Energy performance indicators for the different multiple prosumers layouts

	Baseline	7%	15%	40%	60%	80%	100%
Heq_NR [h]	1571	1558	1545	1499	1463	1431	1404
UFR [-]	-	0.998	0.998	0.994	0.983	0.973	0.949
UHeq_R [h]	-	866	864	790	788	782	739

3.2. Economic analysis

For the single building the transformation from customer to prosumer can be considered always economically profitable: the reduction of the thermal energy costs with respect to the baseline, mainly due to the self-consumption of the produced solar heat, allow a maximum payback period of 10 years even in the limit case of the excess production fed into the DHS for free (Table 4). In all the considered cases the net present value after 10 years is positive

Table 4. Net Present Value and Payback Period for the different solar plant layouts on the single building.

	Baseline	20% Build.	40% Build.	60% Build.	80% Build.	100% Build.
NPV (5%, 10) (0.00) [k€]	-	1.2	3.7	4.6	5.1	5.6
NPV (5%, 10) (0.0225) [k€]	-	1.3	5.2	7.7	10.0	12.1
NPV (5%, 10) (0.045) [k€]	-	1.4	6.7	10.9	14.8	18.7
PP (5%, 10) (0.00) [y]	-	10	9	9	9	10

PP (5%, 10) (0.0225) [y]	-	10	9	9	9	9
PP (5%, 10) (0.045) [y]	-	10	8	8	8	8

In the analyzed case-study, for the DHS utility the transformation of one or more customers in prosumers always leads to a deterioration of the annual cash flow, as shown in Table 5. The earnings before interest, taxes, depreciation and amortization (EBITDA) for the utility decrease, with respect to the baseline, even in the layout with only one prosumer (layout 1 – 7%) and in the limit case in which the excess heat of the prosumer is fed into the DHS for free: the Δ EBITDA would be -0.8%, and it would be -8.4% in the layout with the maximum solar production with the exceeding heat fed in for free. The worst case scenario for the utility is the maximum solar production layout with the highest considered buying price from the prosumer (0.045 €/kWh – 50% of the average selling price to the customers), in which the annual reduction in the EBITDA is approx. 32.5 k€, that is -20.5% worse respect to the baseline. This negative economic performance for the utility in the considered layouts is directly related to the characteristics of the considered case-study, where the heat loads in summer are met mainly by the CHP production and where a relevant part (approx. 58%) of the electric energy produced in summer is self-consumed. In this conditions the solar production is antagonist of the CHP production, and the loss of earnings resulting from the reduction in the thermal energy sold to the prosumers and from the lack of self-consumption (and sale) of the electricity not produced, are not offset by gains from the sale of the excess energy fed into the DHS by the prosumers. From the utility point of view, in this peculiar condition, the presence of prosumers can be acceptable in the hypothesis of new customers/prosumers of the DHS, not of actual customers becoming prosumers.

Table 5. Annual EBITDA and EBITDA variation with respect to the baseline of the DHS utility, for the different solar plant layouts and for different prices of the energy bought from the prosumers.

	Baseline	7%	15%	40%	60%	80%	100%
EBITDA (0.00) [k€]	158.3	157.0	155.7	152.1	151.3	149.5	145.0
EBITDA (0.0225) [k€]	158.3	156.2	154.0	147.6	144.5	140.9	135.4
EBITDA (0.045) [k€]	158.3	155.3	152.3	143.0	137.7	132.4	125.8
Δ EBITDA (0.00) [-]	-	-0.8%	-1.6%	-3.9%	-4.4%	-5.6%	-8.4%
Δ EBITDA (0.0225) [-]	-	-1.3%	-2.7%	-6.8%	-8.7%	-11.0%	-14.5%
Δ EBITDA (0.045) [-]		-1.9%	-3.8%	-9.6%	-13.0%	-16.3%	-20.5%

4. Conclusions and future work

In this paper a case of an actual DHS in which one or more users become prosumers and feed the thermal energy not self-consumed into the grid was analyzed. From an energy point or view, the installation of solar plants reduces the need of fossil fuels of DHS. This is always true in winter season; in summer the solar production involves a decrease of fossil fuel consumption, but it leads to a minor share of self-consumed electrical energy produced by the CHP unit. Naturally this energy has to be delivered anyway by the national electrical grid that uses a share of fossil fuels for the production. From the economic side the user has always convenience to produce by himself the energy for its needs and he can oversize the plant as long as a relevant share of produced energy is self-consumed even in the limit case with the excess energy not remunerated. Instead the cash flow of utility gets worse with the solar plants installation because the solar production is concentrated in summer when a minor thermal load leads to a lower electrical production by the CHP. The lost earnings in electrical production are higher than the earning from the sold excess thermal energy fed in by the prosumers. For a future work, it could be interesting to analyze the presence of prosumers in a DHS where the thermal loads in summer are not fully satisfied by a CHP system, considering also other types of operating principle of the bidirectional thermal exchange.

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