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ALTERNATIVES TO THE DISTRICT HEATING SYSTEMS OF W. MACEDONIA

The case of Ptolemaida

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Abstract

In Western Macedonia, Greece, there are three district heating networks currently in operation, which utilize the heat waste from lignite combustion in PPC's steam-electric power stations, in order to meet the heating needs in Kozani, Ptolemaida and the greater area of Amynteo.

However, the recent developments in the European environmental legislation and the international climate policy have a significant financial impact on the Greek electricity market as well, resulting in an ever decreasing share of lignite in the country's electricity mix during recent years. At the same time, technological progress allows clean energy to directly compete against lignite; as a result, the future participation of lignite in the Greek electricity mix seems ominous.

Thus, it becomes necessary to examine solutions that will meet the future heating needs in Western Macedonia, which are not based on the combined production of heat and power (cogeneration), using lignite as a fuel. This study investigates the economic viability of proposals in order to meet the district heating needs exclusively from Renewable Energy Sources (RES). The city of Ptolemaida was selected indicatively, although similar solutions can be examined in the case of other cities in Western Macedonia.

Taking into account the local RES capacity, four different RES technologies were pre-selected for examination: a) Combined production of heat and power from biogas, b) Thermal solar systems with seasonal heat storage and heat pumps, c) Heat production from biomass boilers and d) Combined production of heat and power (CHP) using the Organic Rankin Cycle (ORC) technology and biomass as fuel. Then, a comparative analysis of six different scenarios was carried out, which combine the above RES technologies.

The scenario with the optimum financial performance is the one where the needs for district heating are exclusively met by CHP-ORC units (Scenario 4), since the assumption of zero profit for the investor (zero net present value after 20 years) corresponds to a decrease in the selling price of thermal energy compared to the present levels. If the objective is zero increase in the selling price of thermal energy, then the higher internal rate of return (IRR), for CHP-ORC units is achieved for a biomass supply cost of 90 €/tn, an objective deemed feasible. However, this solution includes the highest annual fuel needs. Since Scenarios 5 and 6, which also include other renewable energy sources in the district heating mix, show similar financial performances and an initial investment cost of a respective size, while at the same time requiring much smaller quantities of biomass, we consider those as more robust alternative solutions.

The scenarios which are mainly based on the biomass boilers (Scenarios 1-3) show a higher IRR only for increases in the selling price of thermal energy that exceed 50% compared to the present levels. Thus, while the initial investment cost of Scenarios 1-3 is significantly lower, their financial performance is still clearly lower than those of Scenarios based on CHP-ORC units.

All the proposed scenarios achieve much better heating energy supply prices than those of oil, reducing at the same time the environmental load, such as, for example, methane release from organic waste. The possibility to utilize the generated thermal energy throughout the whole year leads to even better financial performance from the operation of the proposed systems.

It is worth noting that the application of the proposed solutions could contribute to the development of parallel financial activities, such as the installation of hydroponic greenhouse units for the development and exploitation of various agricultural products. The

additional income to be generated by these activities can be utilized to subsidize the thermal energy selling price, while at the same time, new professional activities and jobs are expected to be developed, with significant social and environmental secondary financial benefits.

The implementation of the above will contribute to the creation of a sustainable local development model which can partly offset the direct and indirect impact from the expected gradual closing down of PPC's lignite power stations.

It is therefore clear that the dilemma "lignite or oil" in order to meet the thermal needs of the district heating network no longer exists. This study demonstrates economically viable competitive alternatives based on RES, which must be taken into account in the future plans of district heating systems in Western Macedonia.

1. Introduction

1.1. District Heating in Western Macedonia

District Heating (DH) is the generation of thermal energy in buildings and sometimes in production processes through a network of insulated pipes carrying hot water, which is often heated by the heat generated as a by-product of electricity generation. District heating prevents the installation of individual thermal energy generation systems, since thermal energy is centrally generated and supplied to the final users by installing terminal stations (collectors) inside the buildings.

Image 1.1: District heating in Ptolemaida - Connection with the steam-electric power station at Kardia[1]

District heating in Greece only meets a small part of the final demand for space heating (0.2% for the year 2007) and the heat distributed in the network originates from thermal power plants which use conventional fuels. The first small-sized district heating facility in Greece started to operate in Ptolemaida in 1960, in order to meet the heating needs of the PPC settlement at the Eordaia suburb, from the Ptolemaida thermal power station. Nowadays, there are DH facilities in the cities of Kozani, Amynteo, Filotas and Megalopoli, which utilize the thermal load of the nearby thermal power stations, while a CHP power unit has the same role in the city of Serres.

[1] https://goo.gl/HT7Gl2

Image 1.2: Central pump house of the Public Enterprise for District Heating in Ptolemaida (DETIP) at the southern entrance of Ptolemaida[2]

District heating in these cases, except in the city of Serres, has been developed in combination with the municipal enterprises, which purchase heat from PPC (based on a contract) and then distribute it to the final consumers. The municipal enterprise is responsible for the construction and operation of both the network and auxiliary systems.

Ptolemaida began as a pilot system and its success set the standard in Greece. The installation of the DH system at Ptolemaida was followed by the city of Kozani, which set its own system into operation in 1993, the same as the city and communities of the Amynteo area, with their own DH system operating for the first time during the winter of 2004-2005. Currently, planning of DH system facilities is in progress in cities of Central and Eastern Macedonia and Thrace, which will utilize the natural gas pipelines passing through the area.

1.2. Advantages of District Heating

Electricity generation mainly uses fossil fuels, such as natural gas, oil or coal (lignite) in electrical power stations. The electricity generation efficiency usually amounts to over 40%, while the remaining 60% refers to the rejected heat loss in the form of superheated water or steam at temperatures of 120°C-140°C. This overheated water or steam is used to heat the water for DC through a heat exchanger. At the beginning of the supply cycle, the water's temperature is approximately 100°C and when it returns, after it has provided the heat exchanger with energy, its temperature amounts to 40°-60°C. In this way, significant financial and environmental benefits are achieved by utilizing this heat which would otherwise be rejected to the environment. Finally, by applying DH, the standard efficiency of

[2] DETIP. Design and Supervision Department. 2014. Newsletter: "Technical Description of the District Heating System in Ptolemaida", http://goo.gl/6MNJwA

electricity generation rises up to 80%. This process of simultaneous generation of power and useful thermal energy is defined as Combined Production of Heat and Power (CHP).

Thus, the application of DH leads to energy savings of over 30%, since the total rejected heat is utilized. Indicatively, it is noted that each MWh generated with CHP technology reduces CO_2 emissions by 160 kg-500 kg, depending on the fuel used.

The application of DH achieves a significant cost save compared to the direct combustion of any fossil fuel in individual building heating units, since the heat used is relatively cheap and any cost involves the management, transport and distribution of thermal energy. Moreover, DH, being a central system, exhibits a better operation, quality and financial and energy efficiency of heating, due to the constant monitoring and maintenance of the facilities compared to any autonomous heating system. In Greece, the cost of heating from DH systems is at least 50% less compared to oil, while the maintenance cost for the consumers is practically non-existent, since it is integrated in the cost of thermal energy supply[3].

Other major benefits that result, directly or indirectly, from the application of DH include:

- Foreign exchange savings, since the most common heating fuels, namely oil and natural gas, are imported.
- Creating jobs for specialized engineering, technical and administrative personnel during the phases of network construction and facilities operation.
- Low installation and operation cost, facilities safety and space saving in the buildings, since there is no need for a boiler house or a fuel storeroom.
- Lower production cost in greenhouses, drying plants, and other facilities requiring heat

1.3. Description of the current status in Kozani, Amynteo and Ptolemaida

1.3.1. DH in Kozani

The DH network in Kozani[4] was constructed and is operated by the Municipal Enterprise for Water Supply and Sewage in Kozani (DEYAK). The network supplies not only the city of Kozani but also the settlements in the Counties of Nea Haravgi and the Active Urban Planning Zone of Ptolemaida.

Since 1992, approximately 110 mil. euros have been invested in the DH of Kozani, which has been operating since 1994, heating 27,222 apartments out of a total of 5,329 buildings (2012 data), with an overall thermal surface that exceeds 2,450,000 m^2. The deferred peak load amounts to 137 MW_{th} and the total received thermal power amounts to 222 MW_{th}. The overall annual thermal load for consumers amounts to 357,655 MWh, while the heat losses are very low (4.8%). Thus, the total thermal load in the DH network amounts to 375,533 MWh annually. The selling price of thermal energy excluding VAT amounts to 38.50 €/MWh[5].

The investments were funded by european programs, the Public Investment Program (PIP) and own resources of DEYAK, and they were used for the following:

[3] DEYAK, http://goo.gl/G6n9JX
[4] DEYAK. http://goo.gl/XsJn1k
[5] Grammelis P., Rakopoulos D., Margaritis N., Mylona E., Tourlidakis A. 2015, CERTH (CENTRE FOR RESEARCH AND TECHNOLOGY HELLAS) /IDEP (Foundation for the Management of European Lifelong Learning Programmes) "Preliminary design for the upgrading and extension of the DH facilities in Kozani with alternative energy sources", Planning the Transition from Energy-Efficient Cities-Energy Saving at the Level of Municipalities and Citizens, Athens, 11.6.2015.

- The steam extraction facilities from units III, IV and V of PPC's steam-electric power station Agios Dimitrios, with a power capacity of 137 MW_{th}, which produce 70% of the thermal peak load and contribute 95% of the annual thermal energy generation.
- The peak boiler house, with three 10MW boilers and two 27.5 MW boilers. The boilers, with a power capacity of 85 MW_{th}, produce 40% of the thermal peak load and contribute 5% of the annual thermal energy generation.
- Thermal energy storage facility, with a storage capacity of 1,650 m^3 and a power capacity of 80 MWh.
- The pump houses used for transportation and distribution.
- The supply and distribution network, with a total pipe length that exceeds 450 km.

According to DEYAK[5], based on PPC's planning, it is estimated that after 2020, only one system for hot water generation for DH will remain active at unit V of the steam-electric power station Agios Dimitrios. Therefore, the remaining heat load will have to be covered either by another PPC's unit or by other independent heat generation systems (boilers, CHP, etc.).

1.3.2. DH in Amynteo

The Municipal Enterprise for District Heating in the Greater Area of Amynteo[6] (DETEPA) was founded in 1997, as part of the cooperation with the former Amynteo Municipality and the Communities of Levaia and Filotas, as an intra-municipal enterprise, aiming at the installation and operation of a DH system with the combined production of heat by the steam-electric power station at Amynteo–Filotas.

The first construction stage of the DH systemforesaw the installation of the necessary equipment for DH operation at thermal loads of up to 25MW_{th} – as much as the initial capacity of the steam-electric power station, by gradually installing about 1,350 supply systems for consumers.

According to the detailed design of the project, the peak power of the facilities will amount to 34 MW_{th}, as long as 100% of the buildings in the three settlements are linked to it, which corresponds to about 1,900 connections.

The overall project "District Heating in the Greater Area of Amynteo" consists of the following sub-projects:

- Modifications in the steam-electric power station / PPC of Amynteo-Filotas (25 MW)
- Transportation Pipelines
- Distribution Networks
- Main Pump House
- Supply of Thermal Substations
- Installation of Thermal Substations
- Extensions of the Distribution Network
- Pump House /Hydraulic Separation Station at Filotas
- Boilers for thermal energy storage (1,200 m^3)

The system's thermal energy is received by the Amynteo power station through the two-stage turbine steam extraction. The DH system is connected to both units of the steam-electric power station, at 100% backup. To date, one extraction device from each turbine has been constructed and operates, with a nominal thermal capacity of 25 MW_{th}.

[6] DETEPA. "Technical data" http://goo.gl/fXSNid

For the heating period 2014-2015, the total purchase of thermal energy by PPC amounted to 42,731,12 kWh with an average purchase cost of 7.16 €/MWh. The selling price of thermal energy for the consumers amounted, respectively, to 41.26 €/MWh excluding VAT.

Once the other extraction device for each turbine is connected as well, the system's nominal capacity may amount to 40 MW_{th}; in order to meet the daily load variations, thermal energy storage tanks have been installed, with a total capacity of 1,200m^3, which corresponds to 68 MWh.

At the current stage, there are concerns, as well as a research in progress, for alternatives to feed the DH network from the PPC stations, because the Amynteo power station has entered a limited life time derogation status since 1.1.2016, based on article 33 of the Directive on Industrial Emissions (2010/75/EU) and may only operate until 2023 at the latest.

1.3.3. DH in Ptolemaida[7]

The first application of DH in Greece took place in the city of Ptolemaida, where, until 1993, oil was mainly used to heat buildings. At present, 75% of the city's thermal needs are covered by the lignite power stations which are located near the city and carry out the combined production of heat and power.

The Municipal Enterprise for District Heating at Ptolemaida (DETIP), founded in 1994, is the first exclusively municipal enterprise in Greece responsible for securing the thermal energy required by the city of Ptolemaida, while PPC manages the combined production. The Municipality and DETIP have invested more than 60 mil. euros of public and own resources, and they intend to further extend the system, at present in the social housing area and Nea Kardia, and in the future in the communities of Eordaia Municipality.

The DH network was initially (1993) supplied with thermal power of 50 MW_{th} from the lignite unit Ptolemaida III, which stopped operating in November 2014. In 2004, another 25 MW_{th} was added from the steam-electric power station LIPTOL, which was closed down by PPC, as unprofitable, in June 2013. In November 2012, DH was connected to units III and IV of the steam-electric power station at Kardia, with a conventional thermal power of 100 MW_{th} and an actual power supply of 80 MW_{th} to the city. Currently, thermal energy is only generated by the combined production facilities of Units III and IV of the Kardia power station and the peak-backup boiler house, which is located in the facilities of DETIP's main pump house, in the area of the former Ptolemaida agrogarden, with oil as fuel and a boiler with 25 MW_{th}^2 power. As with the Amynteo power station, the Kardia station has also entered a limited lifetime derogation status since 1.1.2016 and may only operate until 2023 at the latest.

The system also includes three vertical cylindrical storage tanks with a total capacity of 1,800 m^3, where thermal energy is stored in the form of hot water, to be used whenever necessary. Specifically, thermal energy is stored during the night, when the load demand in the city is low, to be used during the day and meet the morning and afternoon peak thermal load demand. This achieves the following: a) rational energy management, b) normalizing the combined production units, since it is no longer necessary to monitor on an instantaneous time basis the city's thermal demand and c) minimizing the pump house operation peak, resulting in environmental and financial benefits during the DH operation.

Finally, thermal energy is transported in the form of superheated water from the Kardia power station to the city and the consumers, through a network of twin insulated pipes.

[7] DETIP. http://goo.gl/B1R2wA

Automation and control systems are implemented all over the facilities and in the buildings connected to DH.

In order to be connected, the building owners in Ptolemaida sign a contract, which specifies the respective connection fee per gross square meter of the space to be heated. The selling price of thermal energy is determined by the cost of domestic fuel oil. The connection contract stipulates that it cannot exceed 70% nor drop below 30% of the respective cost of domestic fuel oil. Because of the attractive pricing policy, DETIP has secured the approval of DH by the citizens of Ptolemaida.

According to DETIP's published data, the selling price of thermal energy to consumers for the period 2014-15 amounted to 37.74 €/MWh[8], while the thermal energy supply price by PPC in 2012 was 9.87 €/MWh[9]. Therefore, the thermal energy supply cost from PPC corresponds to about 26% of the selling price to the consumers while the remaining 74% is mainly the operational cost of the DH network, namely personnel expenses, maintenance expenses for electromechanical equipment, amortizations or investments.

Based on the available DETIP data for the winter period 2014-2015, there were 3,860 connected buildings and 14,943 heated apartments, including 55 public buildings with a surface of 102,000 m^2. During the 2013-2014 period, the total annual invoiced load amounted to 159,131 MWh (reduced to the same number of buildings), while for the 2014-2015 period it rose to 183,360 MWh. The annual supply of thermal energy, respectively, from PPC and the combustion of domestic fuel oil during 2013-14 amounted to 208,273 MWh and 234,165 MWh during the period 2014-2015. Consequently, the network efficiency amounted to approximately 77%, significantly lower than the respective DH system in Kozani.

1.4. Need for transition to a different heating model in Western Macedonia

The above DH networks in Greece are directly related to the operation of PPC's lignite power stations. However, due to the recent developments in European environmental legislation which have a significant financial impact, lignite generation has lately been dropping and will continue to do so.

Specifically, since 1.1.2013, all electric power units in Greece are obligated to pay for each ton of CO2 that they emit. Moreover, the changes in the EU Emissions Trading System (EU ETS)[10] that were decided as part of the European 2030 Framework for Climate and Energy, which was only finalized in 2014, are expected to lead to a peak in the CO2 emissions price right amounting from approximately 7.5€/tn in 2014 to 30 €/tn in 2025-2030[11]. This development will significantly add to the operational cost of lignite units in Greece, also given the very poor quality of the Greek lignite deposits[12].

In addition, in 1.1.2016, the Directive on Industrial Emissions (2010/75/EU) came into force, which sets much stricter limits for the remaining gas pollutants (sulfur dioxide, nitrogen oxides, particles, etc.). As part of complying with this Directive, Greece placed the Kardia and

[8] DETIP. "The current DH price discount to the consumer exceeds 66% of the respective oil cost" http://goo.gl/ZUW4zm
[9] Kalaytzidou Ioanna, DETIP Director , 2012 "Prospects for the Development of the District Heating System in Eordaia Municipality" https://goo.gl/J1cf6v
[10] European Parliament, Press Release. 2015. "ETS market stability reserve: MEPs strike deal with Council" http://goo.gl/ovzX5n
[11] Thompson Reuters. 2015. "Reviewing Europe's carbon market: fight for free allocation, slightly higher prices - Carbon prices are estimated to reach €30/t in 2030, according to Point Carbon analysts" http://goo.gl/EUoZxw
[12] PPC, Press Release. 2014. "Booz study comparing the electrical power stations using lignite in Europe" http://goo.gl/04xZTY

Amynteo power stations under a derogation status pursuant to article 33, which means that the two stations will operate for fewer hours and must be closed down by 2023, unless major upgrading investments are carried out, so that they comply with the new, much stricter emission limits. Naturally, this raises a problem in terms of meeting the DH needs in the city of Ptolemaida and the greater area of Amynteo. Moreover, as part of the same Directive, all 5 units of the thermal power station Agios Dimitrios have been integrated in the Transitional National Plan (TNP) and are obligated to receive extended and precise upgradings by June 2020 at the latest[13]. As for units I-IV of the Agios Dimitrios power station, they are expected to close down as obsolete in 2025-2030, which will have an impact on meeting the thermal needs of Kozani as well.

Based on the above developments and the technological progress that now allows clean energy to directly compete with lignite, the future participation of lignite in the Greek electricity generation mix seems ominous. Therefore, in order to meet the future thermal needs of Western Macedonia , it is necessary to examine solutions ***not*** based on the combined production of heat and power using lignite as fuel. To this effect, certain preliminary designs have been elaborated in recent years, which mainly examine the use of biomass or even dry lignite, but without combining it with power generation.

In particular, the EKETA/IDEP recently researched the upgrading and extension of the DH facilities in Kozani with alternative energy sources[5], examining 3 alternative scenarios for meeting part of the thermal load of the DH network in Kozani (biomass boilers, natural gas and combined production of power and heat, using biomass as fuel). Based on the results of the research, all 3 scenarios can potentially demonstrate IRRs of the order of 12%, if DEYAK increases the thermal energy selling price from 3% to 85%. The optimum scenario proved to be the generation of solely thermal energy through biomass boilers, leading to thermal energy selling prices for the consumer that are much closer to the existing levels.

Moreover, in 2010, the Centre for Renewable Energy Sources and Saving (CRES) conducted a preliminary study for the economic viability of the oil boiler, which constitutes the backup unit for DH in Ptolemaida, with a unit for the combined production of power and heat, using biomass as fuel[14]. Despite the fact that the financial results were favorable, the plan did not go forward.

Finally, in 2012, the Technical Chamber of Greece (TEE) / Department of Western Macedonia examined the possibility of utilizing dry lignite in small-scale decentralized energy systems that will meet the heating needs of all the settlements in Western Macedonia with a population of over 1,000 inhabitants (except for the settlements where DH systems are already operating)[15]. Based on the results, in order to ensure the economic viability of the project, the minimum price charged for the thermal energy provided to the consumer ranges, depending on the size of the facilities and the distance from the lignite center which will supply the fuel, from 51€/MWh to 58€/MWh, with an average price of 54€/MWh plus VAT. The proposed solution demonstrates a better performance in terms of pollutant emissions compared to lignite used in the PPC stations. However, in case the heat produced is not a by-product of the electricity generation process, the environmental result is not the optimum one, especially compared to the thermal energy generation systems using RES.

[13] KYA (Joint Ministerial Decision) "Approval of a Transitional National Plan for Reducing Emissions (MESME), pursuant to article 28 of KYA No. 36060/1155/2013 "Setting a framework of rules, measures and procedures for the complete prevention and control of environmental pollution by industrial activities, in compliance with the provisions of Directive 2010/75/EU "on industrial emissions (complete pollution prevention and control)" by the European Parliament and the Council of 24 November 2010" (B΄ 1450), as applicable. Modification of KYA No. 36060/1155/2013 (B΄ 1450)" ", GG B' 20.8.2015

[14] CRES-Biosolesco. 2010. "Feasibility Analysis. District Heating in Ptolemaida, Greece".

[15] TEE/Department of Western Macedonia. 2012. "Proposals by TEE/Department of Western Macedonia for utilizing dry lignite in small-scale decentralized energy systems". http://goo.gl/h1b0Mu

1.5. The european experience

Applying and propagating DH is a priority in the European Union and it is proposed as a suitable technology for heating/cooling cost and energy savings, reducing the greenhouse gases and the energy reliance on imported fossil fuels. For this reason, DH is referred to and promoted as en environmental friendly solution in a series of European Directives, such as the Energy Performance of Buildings Directive (EPBD) and the Energy Efficiency Directive (EED).

The Scandinavian and Central-European countries, with a tradition in the application of DH, have managed in recent years to improve even more the energy, financial and environmental outcome of such systems by using RES. The exploitation of RES already began in the 1990s, as well as the application of the respective technologies, mainly biomass and thermal solar systems, which has currently led to the point of implementing applications of district heating/district cooling systems that rely exclusively on RES.

By utilizing RES, the local societies gain important benefits through coordinated and well-studied cooperative initiatives, thus increasing their income and developing new business activities that create new, high-level jobs. As a result, in many cases, local communities in decline are revitalized, industrial activities are developed and the sectors of research and education are enhanced. Characteristic examples of such cases are the cities Güssing, Austria; Marstal, Denmark; Nacka, Sweden; Milan, Italy; Burgos, Spain; Düsseldorf, Germany; Helsinki, Finland; Poderwijk, Holland; and many others. Three of these will be shortly presented below. Certain cooperative initiatives are described in the Annex, together with an example of a hydroponic greenhouse for the case of Western Macedonia.

1.5.1. The City of Güssing in Austria

During the 1990s, the Mayor of Güssing in Austria, decided, in relation to the studies for the biological treatment and sewage system of the city, to take steps for energy savings and developing renewable energy sources. The main objective was to revive-develop the local economy by exploiting the local energy sources, particularly forest products and residues.

As a result of the powerful political will exhibited by the municipal authorities and the cooperation between the citizens, the local economy benefited in two ways. First, the cost of supplying imported fossil fuels for the generation of energy products, namely power and heat, decreased while at the same time the cost of supplying energy to the consumers through the DH network remained relatively stable and much lower compared to the use of oil. Second, more than 1,100 new jobs were created as a result of exploiting forest products, applying technologies for boilers and combined production units with biomass, and attracting companies and industries, which were installed in the area because of the competitive prices for the supply of thermal energy.

Figure 1.1 shows the evolution of the prices for thermal energy in the DH network and the prices for thermal energy using oil as fuel. Based on this graph, the decrease in the cost of thermal energy since 1996 is obvious, after the DH network came into operation.

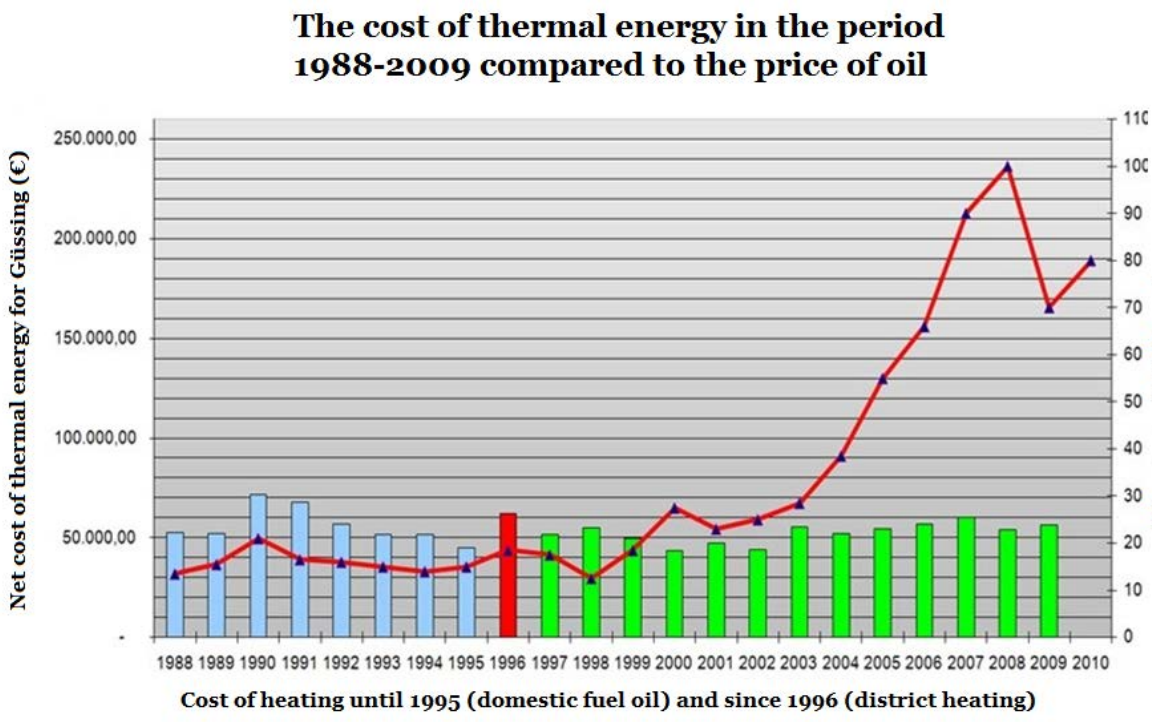

Figure 1.1. Comparison between the cost of DH thermal energy with biomass and oil in the city of Güssing, Austria[16]

The energy city center for the generation of power and heat consists of 4 heat units and 3 CHP units, which meet 71% of the city's energy needs (power and heat) in houses, public buildings and firms. In particular, the installed units generate a total of 56 thermal GWh and 22.2 electrical GWh on an annual basis, which meet a large part of the city's loads, which amount to 60 GWh_{th} and 50.2 GWh_{el} respectively[17].

The DH facilities of Güssing Ltd. use as their main fuel the wood waste from the parquet factories in Güssing. The power generation plant with biomass in Güssing is fed with wood chips from the area (in a 30-40 km radius around the city), which are mainly delivered from the forest of the Burgenland forest association.

Power and heat are also generated by a CHP unit, using a special wood gasification technology developed by the Vienna Technology University. The special characteristics of the produced gas lead to the generation of synthetic natural gas (BioSNG) and synthetic liquid fuel, such as gasoline or diesel (BTL - Biomass to Liquid) and the use of high temperature fuel cells.

[16] Christian Keglovits. 2016. "Güssing: An example for a sustainable energy supply", http://goo.gl/RdXVZq
[17] The Development of Renewable Energy in Güssing, http://goo.gl/EbcifG

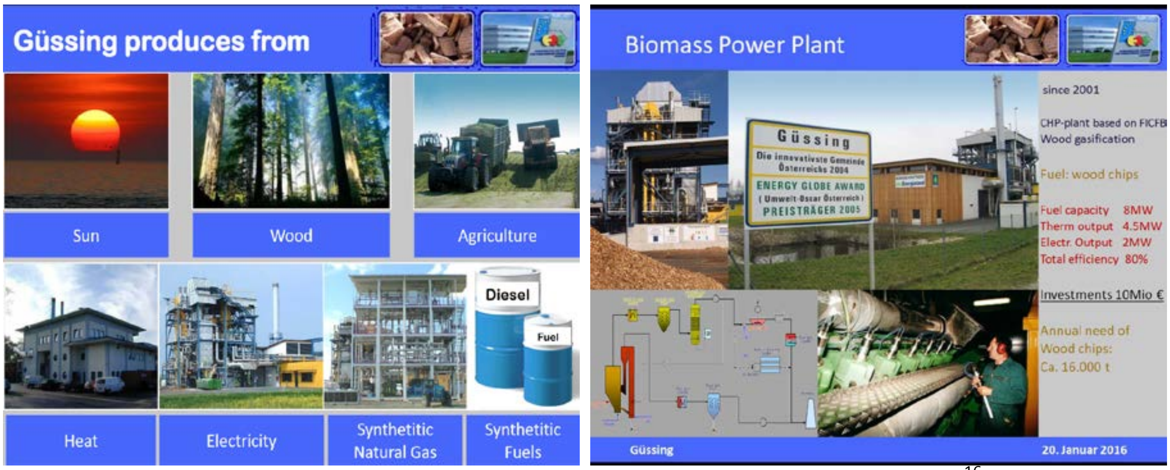

Image 1.3: Energy mix and biomass unit in the city of Güssing[16]

The European Center for Renewable Energy (EEE) was founded in the city of Güssing and it is acknowledged as the top research center in Europe in the sector of wood gasification and 2nd generation biofuel production.

Currently, in the city of Güssing, there are applications implemented and operating which cover a broad spectrum of RES technologies, such as photovoltaic, thermal and solar systems, biogas generation, etc., as well as active RES technology manufacturers and companies.

In conclusion, once the municipal authority's vision for enhancing financial activities in the area of Güssing was implemented, by exploiting the forest biomass and wood by-products, investments amounting to 35.5 mil. euros were carried out, 50 new companies and over 1,100 new jobs were created, while the CO_2 emissions were reduced by 14,500 tons per year.

1.5.2. The City of Marstal in Denmark

Another very interesting example is the city of Marstal, Denmark. The city has a DH network in order to meet the consumers' thermal needs. A gradual approach was applied in order to meet the network's energy needs, by utilizing RES. The final objective, which was achieved, was to meet 100% of the needs from RES.

The following technologies were used[18]:

- 33,360 m^2 of thermal solar systems,
- 75,000 m^3 of seasonal store,
- Biomass boiler with a power of 4 MW_{th},
- CHP unit with ORC (Organic Rankine Cycle) technology, using biomass as fuel, with a power and heat power of 0.75 MW and 3.25 MW respectively,
- High temperature heat pumps with a power of 1.5 MW.

The following image shows a panoramic view of the energy generation facilities in the DH network.

[18] PlanEnergi. 2013. "Summary-Technical Description of the Sunstore 4 Plant in Marstal" http://goo.gl/7P5FAK

Image 1.4: Solar farm and seasonal heat storage in the city of Marstal, Denmark[19]

55% of the thermal load is covered by solar systems, 40% by biomass systems, 4% by heat pumps and only 1% by oil boilers. The total heat generated amounts to 32 GWh annually, while the heat supplied to the consumers amounts to 26.5 GWh annually (17% of total network losses).

As in the case of Güssing, there were many benefits from the application of the above system: increasing the economic and academic activity, improving the energy autonomy with environmental friendly technologies, and achieving competitive and relatively stable selling prices for thermal energy, ranging between 50 and 60 €/MWh, at least 25% cheaper than those of oil.

1.5.3. The City of Poderwijk in Holland[20]

In 2002, the Zeewolde Municipality started to develop a new large residential area, Poderwijk, with 3,000 households, one church, schools and 15,000 m^2 of offices and stores. Then, the Municipality decided to construct an environmentally neutral DH system. The system that was eventually selected consists of the anaerobic co-digestion and operation of CHP stations. This solution was implemented by the energy company Essent Local Energy Solutions, utilizing a dairy farm's by-products in the area with over 140 cows.

In 2007, the owner of the farm started the construction of the biogas generation unit (digestive facilities and two CHP units, one in the farm and one in Poderwijk). During the same year, the first 300 households had already been connected to the system. In late 2008,

[19] CIT Energy Management AB. 2010. "Success Factors in Solar District Heating" http://goo.gl/SJOlCI

[20] BiogasHeat. 2012. "Good practice examples for efficient use of heat from biogas plants" https://goo.gl/1DvX2v

the biogas generation unit and the biogas pipeline between the unit and the residential area were put in operation. By the end of 2010, almost 1,000 houses were connected to the DH system.

Image 1.5: The biogas unit and the Poderwijk settlement in Holland

The project consists of:

- Two digestive facilities and one small CHP unit of 250 kW_{el} in the farm, with a management capacity of 30,000 m^3 of manure and organic materials per year.
- One biogas pipeline between the unit and the settlement.
- One large biogas CHP unit at the outskirts of the new settlement.
- Two backup natural gas boilers which operate as backup heat peak systems.
- One DH network.

Approximately 25% of the biogas generated is used in the CHP plant located in the farm, where the heat is used to heat the digestive facility, the agricultural holdings and the farm buildings. The unit is fed with manure (over 50%) and, in addition, from other substrates, such as corn, grass and waste residues from food industries. The CHP units are located within the stock owner's territory, who sells the generated electrical power to the network.

The CHP unit has an installed power and heat capacity of 1.06 MWel and 1.27 MWth respectively, which produces about 7.5 GWh of power and 7.1 GWh of thermal energy annually. The electrical power generated by the biogas meets the total demand for electrical power and over 75% of the thermal energy consumption. The price of thermal energy for the consumers is related to the price of natural gas.

Finally, the decrease in the CO_2 emissions achieved with this system is 5,100 tons/year and the CO_2 emissions from the consumption of power and heat are 80% lower compared to the use of conventional fuel.

1.5.4. Biogas in Denmark[21]

The biogas capacity in Denmark amounts to 40 PJ or 11,388 GWh, while the energy generation from these units in 2011 came close to 10% thereof (4.1 PJ or 1,138.9 GWh) 46%of which is generated by central units and 27% by units in farms. 22 central units of biogas with a capacity ranging from 1 to 4.5 MW are in operation, as well as 60 biogas units in farms with a capacity ranging from 0.25 to 1 MW. The agricultural facilities of biogas handle a total

[21] BiogasHeat. 2013. "Good practice examples on heat use of biogas plants in Denmark", European Workshop on Heat Use from Biogas Plants – Vienna, Austria, June 12, 2013, http://goo.gl/2YZvnA

of 2.5 million tons of manure (5% of the total generated manure produced) and 0.5 million tons of organic waste.

Biogas is mainly burned in CHP units, while the heat generated is used to heat the digestive facilities in hygiene processes, as well as in DH networks.

All the central agricultural biogas facilities follow this model. In most cases, the CHP unit is an integral part of the biogas unit, but in some cases the biogas is transported through low pressure biogas pipes for a few kilometers to a satellite CHP unit, which uses other fuels in addition to biogas, such as natural gas or biomass.

Special attention is attributed to the fact that the Danish government has been committed to meet 10% (or 2.7 TWh) of the energy needs for the DH networks in the country by 2030 from thermal solar systems with a total surface of 8 million m^2, while the respective target for 2050 is 40% (or 7 TWh).

Respective policies and targets have been adopted by the other Scandinavian countries, converting an energy need and an environmental problem into an opportunity, utilizing the local RES in order to meet their energy needs, and at the same time developing exportable technologies and business, research and academic activities which created and still create thousands of new jobs. In Greece on the contrary, there is zero contribution by the thermal solar or other RES technologies to DH networks.

2. Alternative solutions for DH in the City of Ptolemaida

This study discusses the selection of Renewable Energy Sources (RES) technologies in order to meet 100% of the annual thermal load of a district heating (DH) network. The city of Ptolemaida was selected indicatively, although similar solutions can be examined in the case of other cities in the region of Western Macedonia, Greece.

The necessary conditions for achieving the above target are the maturity of the RES technologies to be used, the existence of adequate RES capacity in the area to address the variable heat loads, and the availability of the necessary land for the implementation of the respective investments. The proposed solutions must be financially competitive in terms of the existing situation and be able to meet the long-term DH needs. Moreover, emphasis is placed on the application of CHP technologies due to the best energy and environmental outcome compared to the heat generation technologies, such as boilers-burners systems.

Taking into account the above necessary conditions, four different RES technologies were pre-selected for examination: a) Combined production of heat and power from biogas, b) Thermal solar systems with seasonal heat storage and heat pumps, c) Heat production from biomass boilers and d) Combined production of heat and power (CHP) using the Organic Rankin Cycle (ORC) technology and biomass as fuel. Then, a comparative analysis of six different scenarios was carried out, which combine the above RES technologies.

The following assumptions were used in the calculations:

1. In order to estimate the heat load to be substituted by other energy forms at the entrance of the DH station in Ptolemaida, it was assumed that half the heat losses refer to the part of the pipe from the PPC collector to the DH station collector. Therefore, taking into account the data of recent years (see section 1.3), it was assumed that the heat required at the entrance of the station amounts to 210 MWh/year.
2. It was assumed that the heat load is currently covered by 95% from the Kardia power station and by 5% from domestic fuel oil. This ratio is never stable and depends on a series of parameters, such as external temperatures, heat availability from PPC, etc. Taking into account this ratio (95%-5%), the supply price of thermal energy from PPC assuming zero adjustment since 2012 (9.87 €/MWh)9, and the average cost of domestic fuel oil, which for the period 2014-2015 amounted, on average, to 85 €/MWh plus VAT[22], it is estimated that the current supply price of thermal energy for DETIP amounts to at least 13.63 €/MWh. This price will constitute the comparison basis for the proposed solutions.
3. The heating needs last 8 months a year (October-May)
4. The dimensionalization of the facilities is based on the availability of adequate power and the storage of thermal energy in order to reduce the installed equipment and the initial cost of fixed equipment, while the proposed solutions are based on utilizing the existing facilities of the DH network, such as the hot water stores.

The basic numerical assumptions on which the financial analyses were based are as follows:

1. The annual tax rate is assumed to be 26%
2. The interest rate is assumed to range between 5% and 8%
3. The discount rate is assumed to be either 3% or 6%
4. The life cycle of the proposed investments is assumed to be 20 years
5. The accounting amortization is assumed to be stable for 10 years
6. The calculations do not include VAT

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[22] DETIP. "The current district heating price discount to the consumer exceeds 66% of the respective oil cost" http://goo.gl/QLIWrS

It is noted that a very significant decrease in the DH needs in the city of Ptolemaida can be achieved by energy saving projects since, according to the information in the buildingcert database of the Ministry of Environment and Energy (YPEN) (https://www.buildingcert.gr/), 86% of detached houses and 84% of blocks of flats belong to energy category D or lower. It is not within the scope of this study to accurately determine the necessary interventions for the energy upgrading of the individual residences, but the most important ones to be examined are as follows:

- Wall and roof insulation
- Replacement of glazing systems (thermally interrupted aluminium frames with double glazing)
- Thermostatic heads on radiators
- Installation of thermal solar systems for the generation of hot water
- Upgrading of automations
- Application and utilization of smart networks and smart meters
- Informing citizens on the optimum energy behavior

Based on the published results of the program "Home Energy Saving"[23], the average energy saving achieved by 2013 amounted to 40% (with an average cost of 9,300€ including VAT), while most interventions included the installation of door and window frames, the installation of a solar water heater and the thermal insulation of the building's envelope (mainly terrace insulation). In addition, it is estimated that the information campaign on optimum energy behavior, the installation of smart meters and the information provided by the energy suppliers, make it possible to reduce energy consumption by up to 20%.

With the application of measures such as those mentioned above, the DH load in the city during the next few years, instead of increasing due to the connection of new consumers, may remain relatively stable or even decrease compared to the current situation, since the thermal energy consumption will be reduced in terms of both space heating and hot water needs. Moreover, any new buildings that are connected to the DH network will have to comply with the minimum specifications for energy efficiency foreseen by the application of KENAK (Regulation for Buildings Energy Efficiency). Specifically, the buildings to be constructed after 2020 will have to be nearly zero energy buildings.

The main technico-economical characteristics of the four RES technologies examined are presented below and then the six combined scenarios are described and analyzed.

2.1. Biogas

In order to make a preliminary estimate of the possibilities to utilize biogas for the combined production of power and heat in the area, two main sources of biogas generation were investigated: a) waste water from biological treatment and b) stockbreeding waste. Other sources, such as organic urban waste or cheese dairy waste, which can further contribute to such a project, were not examined.

2.1.1. Utilizing biological treatment waste

The existing biological treatment facilities in the city handle 5,000 m^3 of urban waste daily, while this capacity is expected to amount to 9,500 m^3 of urban waste daily, according to the installation plan for the facilities[24]. Since the solid waste is 24% per volume on average[25] it

[23] YPEKA (Ministry of Environment, Energy and Climate Change) 07.10.2013 "New Beneficiaries Integration in the Program 'Home Energy Saving' ", http://goo.gl/G9JjtF

[24] Information provided by the manager of biological treatment in Ptolemaida.

will amount to 1,200 kg/day, while after the extension of the facilities it is expected to reach 2,280 kg/day or approximately 360 Nm^3 of biogas/day (1 m^3 of biogas corresponds to about 6.33 kg of solid waste[49]).

Since the lower calorific value of biogas is 6.48 KWh/Nm^3 (lower than that of natural gas,10 KWh/Nm^3, and higher than that of the biogas generated released from landfills, 5.25 KWh/Nm^3)[49], the energy capacity of biological treatment amounts to about 850 MWh/year.

2.1.2. Stockbreeding waste

Stockbreeding waste, as long as it remains undisposed, constitutes a source of pollution for both the atmosphere, due to the released quantities of methane they contain, as well as for surface water and groundwater (nitrate pollution). Stockbreeding waste, whether solid or liquid, must be disposed of based on the relative national[26] and European legislation, so as to ensure sufficient environmental protection. This management is an additional source of cost for stockbreeders.

Alternatively, this waste could be collected and managed centrally, aiming at biogas generation. In this way, the environmental requirements for the operation of stockbreeding units are complied with, without having to undertake the extra cost of waste management.

Nevertheless, in most of these cases, the materials used are either waste or residues, so the anaerobic digestion unit can receive them for free or might possibly charge a certain management fee. This cost is related to the gas released from the material and may range from 10 to 200 €/tn, depending on the material introduced to the unit[27]. A small financial price/incentive could potentially be paid, the amount of which will have to be specified based on the economic viability of any investments. The specification of this price does not fall within the scope of this study. The stockbreeding units and the respective numbers of animals in the greater area of Kozani Prefecture[28], as well as the biogas content per animal and per day, are listed on Table 2.1.[29]

Table 2.1: Biogas generation capacity from stockbreeding waste in Kozani Prefecture

	Cattle	**Pigs**	**Sheep and Goats**	**Poultry**
Manure quantity (m^3/day/animal)	0.0681	0.0045	0.0177	0.027
Biogas (m^3/day/animal)	1.2735	0.54	0.24	0.012
Number of stockbreeding units in Kozani Prefecture	361	773	2,225	4,486
Number of animals in Kozani Prefecture	15,271	11,193	266,317	165,223
Energy generation capacity* (GWh/year)	42.6	13.2	140.0	4.3
Total energy generation capacity* (GWh/year)				**200.1**

* The energy content of biogas is approximately[30] 6kWh/m^3.

[25] Kabouridis, L., Thessaloniki Water Supply and Sewerage Company S.A. (EYATH S.A.), Directorate of Quality and Environmental Control, Heleco '05, TEE, February 2005. "Combined Production of Power and Heat in the Thessaloniki Waste Treatment Facilities". http://goo.gl/brrTDP

[26] See indicatively Joint Ministerial Decision (KYA) 46296/14.08.2013 (GG 2002/B/2013), Law 4014/2011 (GG 209/A/2011), Law 4056/2012 (GG 52/A/2012), KYA Y1b/2000/95 (GG 343B/4.5.95), European Union Regulation 1069/2009/EC of 21.10.09

[27] Bisyplan. "Planning Guide for Bio-Energy Systems" http://goo.gl/6yojrI

[28] Hellenic National Statistics Service. http://goo.gl/JYwIwS

[29] ASABE Standard D384.2. 2005. "Manure production characteristics; NCSU EBAE 071-80" http://goo.gl/TcOmW3

[30] Bond, T. and Templeton, M.R. 2011. "History and future of domestic biogas plants in the developing world", Energy for Sustainable Development, Vol: 15, Pages: 347-354. http://goo.gl/P0CEFk

For the needs of this study, only a part -and not the total- of the above capacity was taken into account. The main reasons were that the animals' stabling time is approximately half as much as the one mentioned in the relevant literature and the manure transportation range must not exceed 10-15 km[31] –otherwise, the cost of transportation, as well as the environmental footprint, are significantly higher. The fact that not all the quantities will be available must also be taken into account, because there might be other competitive uses, such as utilization by the stockbreeding units themselves. Taking into account these three parameters, it must be assumed that only 5-10% of this capacity (10-20 GWh/year) is available. Including the biogas from the biological treatment, the total available capacity to be used in the analyses to follow amounts to 20.85 GWh/year.

This capacity is obviously not enough to meet the heat load of Ptolemaida. Nevertheless, it will be included in the calculations mainly due to the attractive economic aspects of a CHP unit using biogas, which can be utilized to offset the cost of extending or installing the biological treatment.

2.1.3. Combined Production of Heat and Power from biogas

Based on the literature, the suitable method for utilizing the energy capacity from the residues of stockbreeding units and biological treatment is to use the anaerobic digestion (AD) and the combustion of the generated biogas in a CHP unit. This method is used, in addition to the utilization of biogas for the generation of power and heat, to produce high quality organic fertilizers.

AD is a biochemical process during which complex organic compounds are decomposed without oxygen by various types of anaerobic microorganisms. The AD products are the biogas and the digested residue; a broad range of biomass types can be used as raw material for their production:

- Solid manure and slurry
- Agricultural residues and by-products
- Organic waste that can undergo digestion, originating from food and agricultural industries (from plants and animals)
- The organic fraction of urban waste and home residues (from plants and animals)
- Sewage sludge
- Energy crops (e.g. corn, miscanthus (silvergrass), sorghum, alfalfa).

A simplified flowchart of the AD process is shown on Figure 2.1, where the four main stages of the process are distinct: hydrolysis, acidogenesis, acetogenesis and methanogenesis[32], while Figure 2.2 shows a standard unit for biogas generation and utilization using the method of anaerobic digestion[33].

[31] This radius extends to about 10%-20% of the total surface in Kozani Prefecture, namely 3,516 km^2

[32] CRES. 2009. "Biogas Manual, BiG>East" http://goo.gl/KZrQox

[33] AEGIS Energy EPC Renewables: Big Units http://goo.gl/aLKr0t

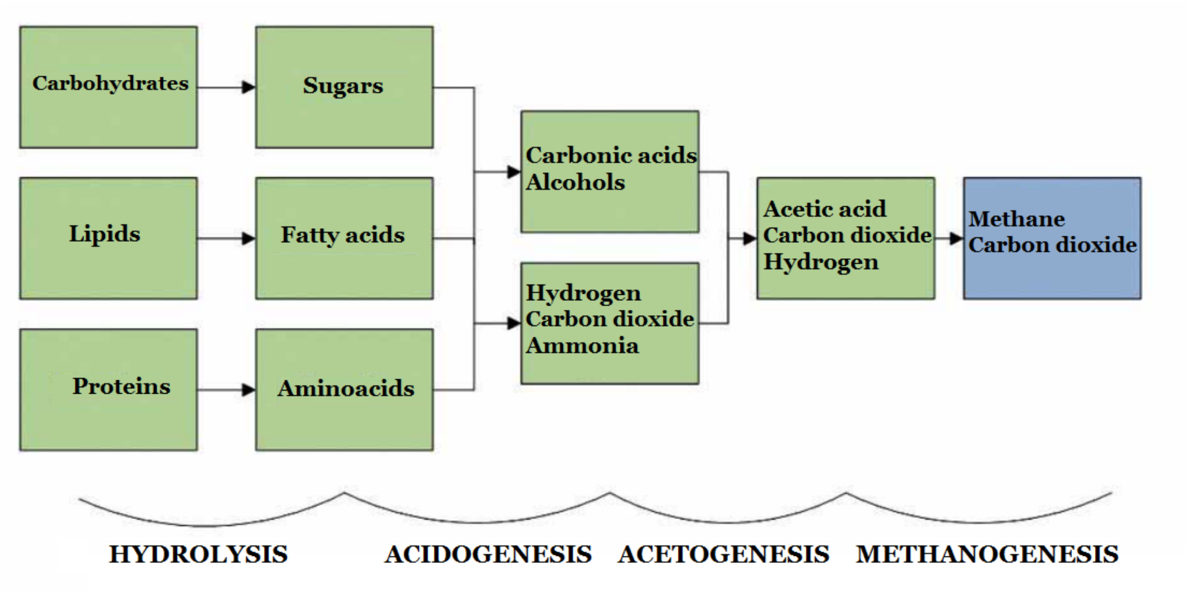


Figure 2.1: The main steps of the Anaerobic Digestion process[32]

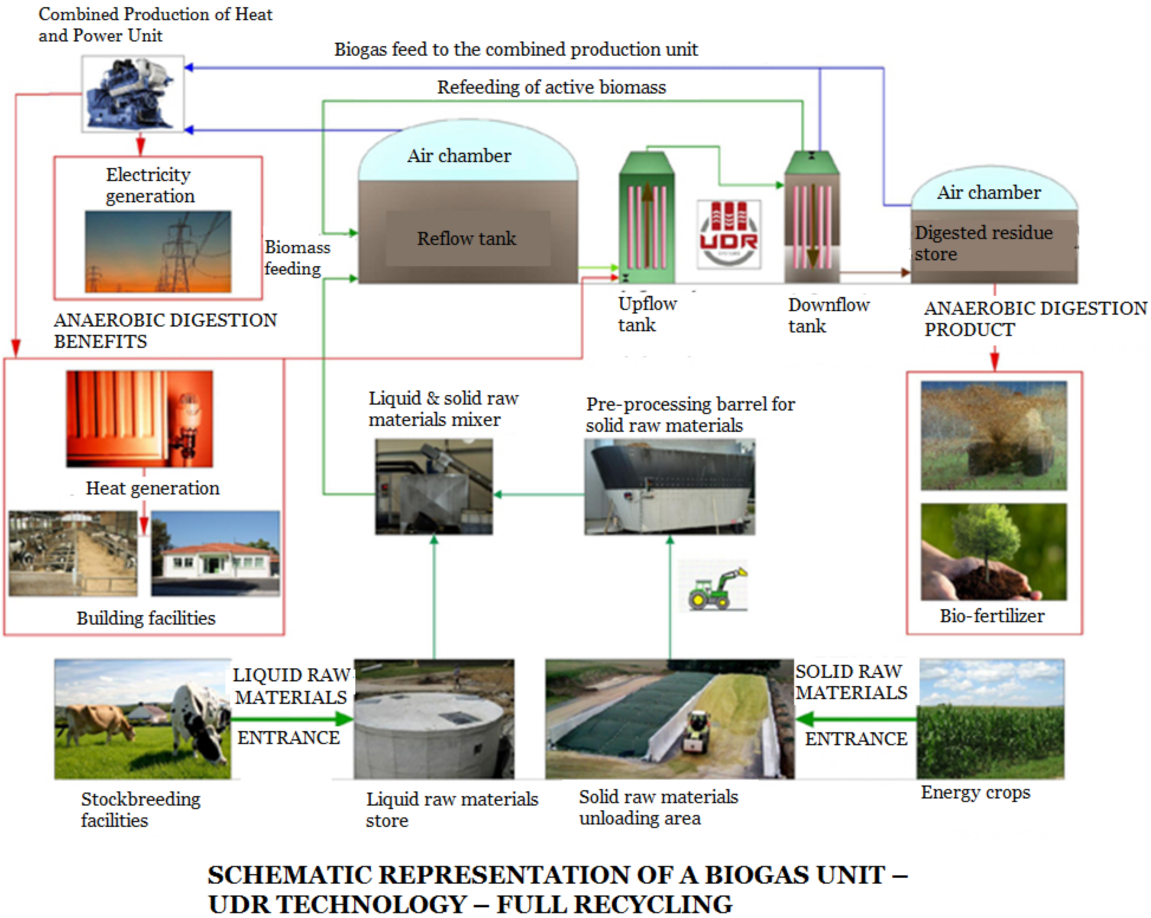


Figure 2.2: Schematic Description of a Biogas Unit[29]

In Greece, despite the substantial capacity of the undisposed organic waste, the biogas as RES has been utilized to a minimal extent. The installed units for biogas generation have a total power of 44.13 MW_{el} and mainly involve solid waste landfills and municipal facilities for waste water treatment (4 small agricultural units with a total capacity of 1.73 MW_{el} and 2 industrial units with a total capacity of 1.18 MW_{el}). However, according to the estimates by CRES[32], it is considered that only the anaerobic digestion of waste from animals, slaughterhouses and dairy plants could be used to feed combined production units, with a total capacity of 350 MW and an approximate annual power generation of 1.12 TWh_{el}. The utilization of organic waste for biogas generation has not only financial, but also major environmental benefits. Based on the CRES data, the utilization of all this capacity could reduce the greenhouse gas emissions by up to 3.7 million tons of CO_2 annually, a quantity corresponding to emissions of 1.2 million tons of oil.

2.1.4. Technico-economic parameters

In order to assess the capacity of the combined production unit that will utilize the available biogas capacity amounting to 20.85 GWh/year, a total efficiency ratio of 85% is assumed.[34] The CHP unit could only operate during the winter period, but this would mean that a unit with greater capacity should be installed in order to utilize the same quantity of fuel, resulting in a higher investment cost. For this reason, it was assumed that the unit will operate at full load, almost all year long (7,920 operating hours/year for 22 operating hours/day, 30 days/month and 12 months/year). The most suitable CHP technology in order to utilize the biogas for the estimated power class is internal combustion engines. Based on literature and the technical characteristics provided by various manufacturers, the power–to-heat ratio for this specific technology is 1 to 1.2[35].

Based on all the above, in order to utilize the 20.85 GWh/year of biogas from biological treatment and stockbreeding waste, the CHP unit must have an electrical and heat capacity amounting to 1.02 MW and 1.22 MW respectively. The generated power and heat will amount to 8.06 GWh and 9.66 GWh/year, respectively. 30% of the generated heat is assumed to constitute own consumption. The assumptions as well as the main operational characteristics of the CHP unit presented in this section are summarized in Table 2.2:

Table 2.2: Operational characteristics of the CHP unit using biogas

Fuel	Biogas from biological treatment and stockbreeding
Fuel quantity per year	3,445,300 m^3
Utilized primary biogas energy	20.85 GWh
Efficiency	85%
Operating hours per year	7,920
Heat to Power Ratio	1.2:1
Generated thermal energy	9.66 GWh
Thermal energy sold	6.76 GWh
Electricity sold	8.06 GWh
Thermal energy	1.22 MW
Electrical power	1.02 MW
Manure generated per year[36]	6,000 tons

[34] OECD/IEA. 2007. "IEA Energy Technology Essentials. Biomass for Power Generation and CHP" https://goo.gl/O46muk
[35] Technical Instruction by the Technical Chambers of Greece (TOTEE) 20701-5/2012. 2012. "Combined Production of Cooling, Heat and Power: Building Installations" http://goo.gl/BJLRto
[36] Vavouraki, Aikaterini. LIFE08 ENV/GR/000578, INTEGRASTE "Development of integrated agroindustrial waste management politics maximizing materials recovery and energy exploitation" http://goo.gl/TxSrDM

The estimated investment cost for the unit collecting and utilizing the biogas generated from the solid organic waste of the bred animals is of the order of €4 million[37] Taking into account that the selling price of the power generated by biogas units with a capacity below 3 MW is 230 €/MWh, when using biogas from stockbreeding waste, and 131 €/MWh, when using biogas from biological treatment, the annual income amounts to €1,828,473. Moreover, based on the estimated generated quantities of compost (fertilizer) and with a selling price of 50 €/tons[38], the respective annual income amounts to €300,000.

The unit's operational costs include the manure removal cost, the operation and maintenance cost of the facilities and the labor cost. According to literature, there are various estimates for the operational cost of the biogas units, ranging from 10% to 42%. For the needs of this study, this cost is assumed to be 30% of the fixed investment. Therefore, the annual removal cost, operation/maintenance cost and labor cost amount to €1,200,000. Table 2.3 summarizes the basic financial data of the investment:

Table 2.3: Financial data for the CHP unit with biogas

Parameter	**Price**
Selling price for the biogas electricity generated from stockbreeding waste	230 €/MWh
Selling price for the biogas electricity generated from biological treatment	131 €/MWh
Selling price of organic compost	50 €/ton
Installation cost (1.02 MW_{el}, 1.22 MW_{th})	4,000,000 €
Income from electricity sales	1,828,473 €
Income from compost sales	300,000 €
Annual operating cost	1,200,000 €

2.2. Thermal solar Systems with seasonal heat storage and heat pumps.

The thermal solar systems (TSS) convert solar energy into heat. A thermal solar system collects, stores and distributes solar energy using some fluid medium for heat transfer, usually water, which can be heated in a temperature range of 60°C- 110°C. For this reason, the energy solar systems are suitable for all the applications requiring heat, such as space heating or cooling and usable hot water generation (district heating and district cooling networks), for industrial processes, even for electricity generation.

The most common use of thermal solar systems is the usable hot water generation. During the last 15 years, the thermal solar systems are also widely used in district heating and district cooling networks, as well as in various industrial processes, such as drying, or in slaughterhouses. They are classified depending on their technology, such as flat plate collectors (simple or selective), vacuum collectors (see Figure 2.3), or depending on the water circulation method, namely with natural or forced circulation; they are also divided into autonomous and central systems.

[37] Agroenergy. "Development of biogas generation plants" http://goo.gl/YsEBHG
[38] Ntoulias D. 2012. "Researching the economic viability of a mixed unit for organic waste processing in the area of Mikri Lakka, Souli", https://goo.gl/ycpYoR

 Flat plate collectors	 Vacuum collectors

Figure 2.3: The two main CHP technologies, namely flat plate collectors and vacuum collectors.

In many cases, the heat generated from thermal solar systems does not equal the demand. For this reason, it is necessary to store the generated thermal energy in suitable thermally insulated stores, whose dimensions depend on the storage needs either for short (a few days) or much longer time periods. The last category is called seasonal storage.

Research for the technology of large-scale seasonal heat storage began in Europe in the mid 1970s. Since then, dozens of applications have been implemented, mainly in Sweden, Denmark, Switzerland and Germany. In Greece, two medium-scale demonstration projects of seasonal heat storage have been implemented, using thermal solar systems. The first application is located at the Solar Village in Lykovryssi and the second one at the CRES facilities in Pikermi.

The logic behind seasonal storage is simple: all kinds of energy solar systems, including thermal solar systems, generate the larger percentage of useful energy, thermal in this case, during the summer period. A DH network requires thermal energy for space heating during the winter period. Therefore, in order to utilize the thermal energy generated from thermal solar systems in the summer, it will have to be stored so it can feed the DH network during the winter. The following figure shows a standard application of seasonal storage with thermal solar systems that feed a DH network. This standard facilities include the central station for energy collection, generation and management, the seasonal stores, the DH network, the buildings connected to the DH network and the solar collectors installed on building roofs.

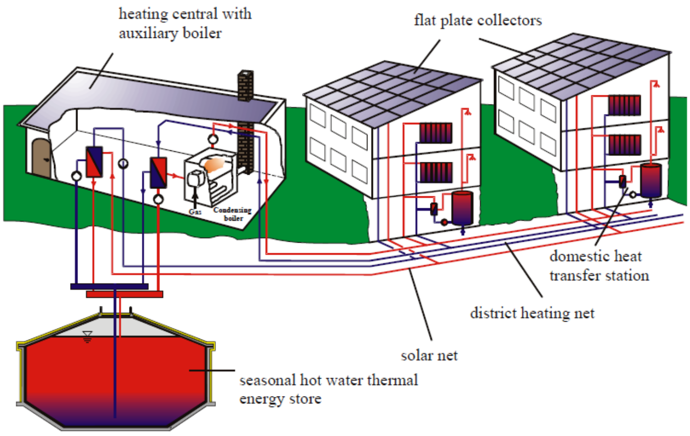


Figure 2.4: Feeding thermal energy to a DH network from thermal solar systems through seasonal storage[39]

[39] High-Combi. 2008. High Solar Fraction Heating and Colling Systems with Combination of Innovative Components and Methods, Work Package 2, Deliverable D6. “State of The Art Applications”. http://goo.gl/hWeq69

2.2.1 . Technico-economic parameters

Taking into account issues concerning layout and land availability to support DH in the city of Ptolemaida, it is proposed to install a thermal solar collectors of total surface area in the order of 15,000 m^2. The necessary land for these facilities, taking into account the collectors tilt angle (approximately 45°), amounts to 30,000 m^2. Based on the solar radiation data and the efficiency of the selective solar collectors (~ 700 kWh/m^2), it is estimated that the annually generated thermal energy amounts to 10 GWh.

Given that the largest part of the utilized solar energy is available during the summer period, while the demand for thermal energy emerges during the winter period, the application of seasonal heat storage must be considered. Consequently, the storage units will have to be designed for a storage period of approximately 4 months. The necessary storage volume ranges between 1.3-5 m^3/m^2 of collector surface area, depending on the selected storage technology[40]. For this application, an average value of 3 m^3/m^2 of collector area is assumed. Therefore, the total volume for an areaof 15,000 m^2 of solar collectors amounts to approximately 45,000 m^3.

Utilizing this heat with a high temperature heat pump can achieve a high seasonal energy efficiency ratio of 3.6 – 4, based on manufacturers' data. By selecting an average seasonal energy efficiency ratio within this range (3.8), the solar thermal system (10 GWh) can generate approximately 38 GWh of thermal energy annually. Assuming that the heat pumps using the energy generated by the solar thermal system will operate 22 hours per day during the heating period in Ptolemaida (8 months per year), it is calculated that the necessary capacity will amount to almost 2 MW. The basic constructional and operational aspects of the proposed system are shown in Table 2.4.

Table 2.4: Constructional and operational aspects of the solar thermal system with seasonal storage and heat pumps

Parameter	**Price**
Solar collectors surface	15,000 m^2
Surface required	30,000 m^2
Annual thermal energy generation of the solar thermal system	10 GWh
Storage duration	4 months
Necessary storage volume for the proposed system	45,000 m^3
Heat pumps power	2 MW
Operating hours of heat pumps per year	5,280
Total generated heat per year	38 GWh

The reduced cost of the proposed solar system, including the storage units, amounts to approximately 300 €/m^2 of collector[41]. Therefore, the total cost of the solar system together with the storage facility amounts to approximately €4,500,000. The cost of the high temperature heat pumps, based on the manufacturers' data, amounts to 700,000 €/MW[40]. Thus, the total cost of the system amounts to €5,900,000. The annual maintenance cost of the system amounts to 2% of the investment cost[40], namely approximately €118,000. The annual operational cost (electricity) of the equipment amounts to 1,056,000 €, given that the heat pumps (2 MW) will operate for 5,280 hours, i.e. consuming 10,560 MWh annually. Thus, the total cost of the system maintenance and operation amounts to €1,174,000.

[40] High Combi – High Solar Fraction Heating and Cooling Systems with combination of innovative components and methods, http://goo.gl/MbNcVH

[41] Pardo Garcia Nicolas et al. 2012. "Best available technologies for the heat and cooling market in the European Union" http://goo.gl/3hCIvB

Table 2.5: Financial aspects of the solar thermal system with seasonal storage and heat pumps

Parameter	**Price**
Reduced cost of solar thermal system and store	300 €/m^2 of solar collectors
Installation cost of the solar thermal system and store	€ 4,500,000
Unit cost of heat pumps	700,000 €/MW
Installation cost of heat pumps	€ 1,400,000
Total installation cost	€ 5,900,000
Annual maintenance cost	118,000
Electricity price for heat pumps	100 €/MWh
Annual electricity cost	€ 1,056,000
Annual operation and maintenance cost	€ 1,174,000

2.3. Biomass

2.3.1. Biomass capacity in Western Macedonia

In order to assess the available biomass capacity in Western Macedonia and especially in the areas of interest for the DH networks of Ptolemaida, Amynteo and Kozani, several studies have been conducted and the available data have been presented in publications and one-day conferences. According to the Public Enterprise for District Heating in Ptolemaida (DETIP)[42], the available biomass capacity in Western Macedonia mainly originates from forest biomass (125,000 tons/year) and agricultural residues (201,000 tons/year) with a respective total thermal content of 1,630 GWh/year. The Public Enterprise for District Heating in the Greater Area of Amynteo (DETEPA) estimates that the biomass capacity in the greater area of Amynteo, Florina and Eordaia amounts to approximately 146,000 tons or 730 GWh/year, with the largest part originating from corn crops (about 66,000 tons/year)[43]. Particularly for the Kozani Prefecture, where the city of Ptolemaida belongs in administrative and geographical terms, the available biomass quantities amount to approximately 279,000 tons/year with a thermal content of 1,435 GWh/year (see Table 2.6)[44].

Table 2.6: Available biomass in Kozani Prefecture

Biomass	Kozani Prefecture			
Crops/Residues	**Tons/year**	**Average Lower Calorific Value of Crops (MJ/Kg)**	**MJ/year**	**GWh/year**
Arable land	216,136	18.5	3,998,516,000	1110.79
Trees	24,467	19.95	488,116,650	135.60
Forests	10,491	18.57	194,817,870	54.12
Energy crops	6,000	18.96	113,760,000	31.60
Agro-industrial crops	21,640	17.2	372,208,000	103.40
Total	**278,734**		**5,167,418,520**	**1,435.51**

[42] Petridis N., Municipal Enterprise for District Heating at Ptolemaida (DETIP). 2015. "District Heating in Ptolemaida–Unit for the Combined Production of Power and Heat, with Biomass as Fuel", Conference: The Use of Biomass in District Heating-A Realistic Approach, http://goo.gl/O2IjLR
[43] Kyriakopoulos K. Public Enterprise for District Heating in the Greater Area of Amynteo (DETEPA). 2015, "The case of energy generation with biomass in the Amynteo District Heating", Conference: The Use of Biomass in District Heating-A Realistic Approach, http://goo.gl/Pi87VR
[44] Zabaniotou A. 2010. Study on Biomass Availability in the Region of Western Macedonia", D1 Project Deliverable LIFE08ENVGR576, http://goo.gl/dz0Ia8

Although the various studies greatly differ in their estimate of the biomass capacity, and this estimate refers either to the greater area of Western Macedonia or the Kozani Prefecture or parts thereof, it is still sufficient to meet the thermal needs of the DH network in Ptolemaida. Moreover, the option to develop energy crops must be taken into account, if there is additional demand for biomass for other cities. Cardoon crops are particularly interesting since, according to a series of studies, it is the most suitable plant given the prevailing weather conditions in Greece, as well as due to the plant's endurance and the limited requirements for its cultivation.

2.3.2. Biomass cost

The cost of biomass supply represents the most important parameter of the operational cost for both technologies examined (biomass boilers and CHP-ORC unit). For this reason, in the calculations, the unit cost of biomass supply has been considered as a parameter, and the relevant sensitivity analysis was carried out with a range of 70-150 €/tn. The lower limit was selected based on the bids submitted to DETIP for the supply of 2,700 tons of agricultural residues (straw) in the form of a ball, with the unit cost ranging between 70-75 €/tn[42], while the upper limit was selected based on the price of the industrial briquette. The reference supply price selected for the unit cost of biomass was 90 €/tn, since the bids submitted to DETIP for the supply of 16,000 tons of wood in the form of chips were within this range)[42]. Moreover, the price of 90 €/tn corresponds to a logical biomass mix ratio, consisting of 75% straw at 70 €/tn and 25% briquette at 150 €/tn.

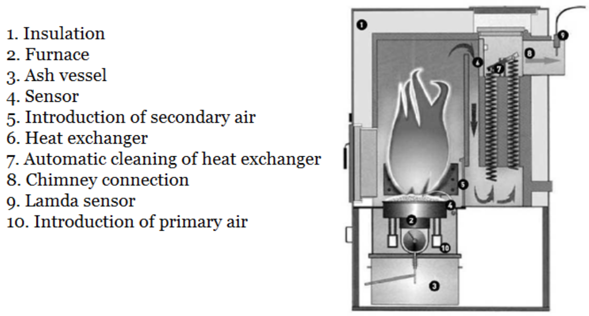
2.3.3. Biomass boilers

The most important technology for utilizing biomass is the biomass boiler-burner system (henceforth 'biomass boiler'). The biomass boilers do not differ at all, in principle, from the common oil or gas boilers. The main parts of such a unit consist of the biomass storage unit, the automatic fuel feeding system, the burner, the combustion chamber and the operational automations of the system.

Depending on the application, the biomass boilers use a different type of biomass as fuel. Small applications mostly use wood pellets, while in larger applications (e.g. district heating), the biomass boilers can be fed with different type of solid biomass, such as wood chips, pellets or briquettes. An important parameter for the efficient operation of the biomass systems is the humidity contained in the biomass. In small boilers, the humidity content cannot exceed 20% and in larger applications it can reach up to 40%. The modern boilers of solid biomass present the following characteristics[45]:

- Combustion efficiency over 85%.
- Low emissions of carbon monoxide and ash at full load operation.
- Possibility for the generated power to vary, depending on the load required.
- Possibility to control combustion by remote control.
- Automated operation for the minimization of the maintenance requirements.

[45] Efthimiadis A., Galanis N and Kalliakoudi K. 2014. Alternative technologies for heating-energy saving" http://goo.gl/JxgCwm



Boiler for solid biomass combustion[45]

Biomass combustion station[46]

Figure 2.6: Standard boiler for solid biomass combustion

For the needs of this study, the reduced investment cost of the proposed system, also including the cost of electromechanical equipment, land, storage, etc., amounts to approximately 300,000 €/MW, and the average annual maintenance cost of the system amounts to 4% of the investment cost[41]. In order to minimize the investment cost, it is assumed that the existing thermal energy storage tanks, with an equivalent capacity of 25 MW, will be utilized, and that extra storage power will be added, depending on the selected (in each scenario) capacity of the biomass boiler.

2.3.4. Combined production of heat and power with the Organic Rankin Cycle (ORC) Technology

Apart from the technology for the generation of only thermal energy by biomass combustion with a simple boiler, the possibility of combined production of heat and power was also examined, due to the attractive financial prospects of the latter. In order to convert thermal energy from biomass into electricity, the use of units based on the ORC technology with the use of diathermic oil was investigated. The boiler uses the diathermic oil's temperature to preheat and vaporize a special organic liquid inside the evaporator. The special organic liquid moves the turbine which is directly connected to one power generator, while the steam passes through a heat exchanger which heats the organic liquid.

The main advantage of this particular technology using the organic liquid compared to a classic steam generator is that the organic liquid may have a very strong flow and move a turbine with a larger diameter than the steam, without damage on the fins and the metal parts of the turbine.

Moreover, an ORC unit achieves the following:

- Power to heat ration 1 to 4
- Availability over 98%.
- Easy variation in the operational range of the unit from 10% to 100%.
- High efficiency even with a partial load.

[46] National Boiler Service. http://goo.gl/MD1pIm

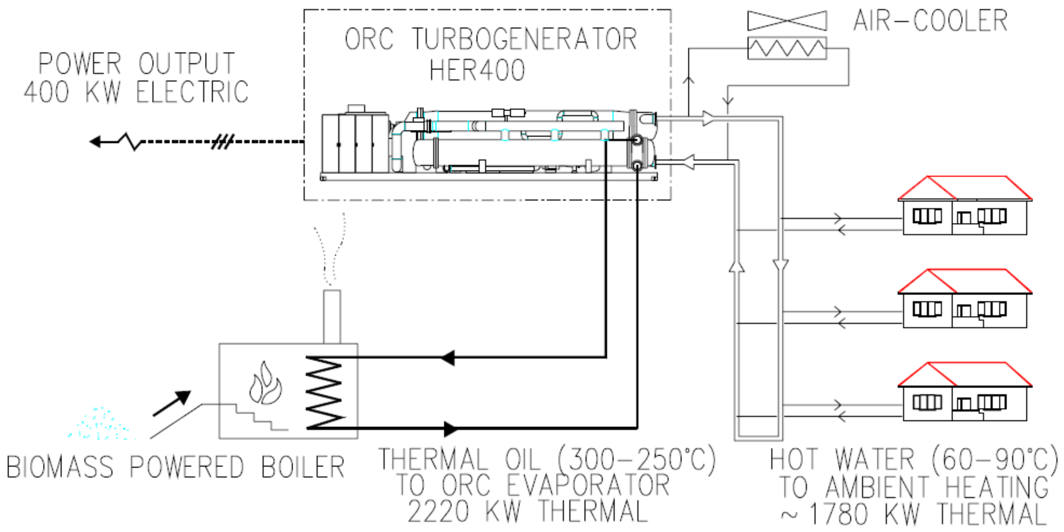


Figure 2.7: Schematic diagram of a CHP unit with ORC technology and biomass as fuel[47]

As regards the financial data for the needs of this study, the selling price of electricity to the network, which is generated from biomass units with a capacity ranging between 1-5 MW, amounts to 170€/MWh. The reduced investment cost (electromechanical equipment, stores, fuel transportation and management systems, etc.) of the CHP unit and the biomass boilers amounts to approximately €4.75 million /MW. The operation and maintenance cost (except for the fuel), according to the literature and the manuf acturers, amounts to about 4% of the fixed investment.

[47] Bini Roberto and Manciano Enrico. 1996. "Organic Rankine Cycle turbogenerators for combined heat and power production from biomass" http://goo.gl/YXpG2l

3. Economic analysis - Scenarios

Given the available biogas capacity and the restriction practices for the installation of the thermal solar systems and seasonal storage tanks, these two new energy sources are not sufficient to cover the thermal loads of the DH network. Only in the case of biomass there is enough capacity to meet the total thermal needs of the DH network in the city of Ptolemaida.

For this reason, six scenarios were examined, mainly involving technology combinations of the four RES except for the cases of the biomass boilers and the CHP-ORC, which were also examined as distinct scenarios. In the scenarios using a technology mix, each individual investment must be viable on its own. This restriction, without affecting the total solution, allows the partial and/or gradual implementation of the whole without requiring cross investments.

It is assumed that it is possible to cover the investment of solar thermal systems and biomass by 40% from subsidization, by 40% from loans and by 20% from own capital. In cases of combined production of power and heat using biomass and biogas, it was assumed that it is possible to cover 60% of the investment from loans and 40% from own capital. The reason for not assuming exactly the same funding model considered in the other cases is that the CHP model significantly increases the income from electricity generation due to a better Feed in Tariff (FiT). The FiT for electricity, without financial aid which were used in the calculations for the combined productions units, are those prescribed by the applicable law (4254/2014) and are listed in the table below:

Table 3.1: Guaranteed prices pursuant to Law 4254/2014

Electricity generation from:	**Guaranteed Price (€/MWh)**
Biogas from stockbreeding waste	230
Biogas from biological treatment	131
Biomass for units of 1-5 MW	170
Biomass for units above 5 MW	148

The economic analysis of the 6 scenarios was carried out with two approaches-targets:

A. Minimizing the cost for the consumer, given the social aspect of DH. This approach assumes that the Net Present Value (NPV) after 20 years equals zero, namely the total investment is balanced and does not yield any profit. Then, the necessary modification of the thermal energy selling price to the DH network is calculated, for various biomass supply prices in the range of 70 – 150 €/tn.

B. The optimum financial performance of the investments. This approach shows the variations in the basic economic parameters of the investment, namely the Net Present Value (NPV), the Internal Rate of Return (IRR) and the investment Payback Period (PP), for different selling prices of thermal energy, assuming the reference supply price for the biomass (90 €/tn).

Selling prices for the generated thermal energy up to 30 €/MWh higher than the current levels were examined. The basic economic analysis of the 6 scenarios assumed an interest rate (IR) of 3% and a discount rate of (DR) 5%. In the following sections the 6 scenarios are presented, together with the results of their economic analysis.

3.1. Scenario 1: Biomass boilers

This scenario examines the possibility to meet the total thermal needs of the DH network, using only the biomass boilers and storing thermal energy. This scenario is characterized by the lowest initial investment cost. The basic technico-economic characteristics of the unit are listed on the following table.

Table 3.2: Technico-Economic Characteristics for Scenario 1

Biomass Boilers	Unit installation capacity	60 MW_{th}
Fuel consumption	Biomass fuel	46,667 tons/year
Energy generation	Heat sold	210 GWh/year
Expenses	Installation cost	18,500,000 €
	Operation and maintenance cost (except for the biomass cost)	158,400 €/year

Table 3.3 shows the necessary variation in the selling price of thermal energy for various prices of biomass supply, in order to make the investment marginally viable with a zero net present value (NPV=0) after 20 years. It is noted that, even with the lowest fuel cost price, it is necessary to increase the selling price of thermal energy by 10 €/MWh compared to the present levels (27% increase). As regards the maximum fuel cost, the increase in the selling price of thermal energy amounts to almost 28 €/MWh, but still remains below 77% of the domestic fuel oil.

Table 3.3: Variation in the selling price of thermal energy compared to the biomass supply price for zero NPV (*approach A*) for Scenario 1.

Biomass Supply Cost (€/tn)	Variation in the selling price of thermal energy (€/MWh)
70	+9.98
80	+12.20
90	+14.42
100	+16.64
110	+18.87
120	+21.09
130	+23.31
140	+25.53
150	+27.76

Table 3.4 shows the results of the second approach, namely the net present value at the end of the investment, its internal rate of return and the investment payback period for a fixed supply price of biomass that equals the reference price (90€/tn). The investment starts to show a positive net present value for an increase in the selling price of thermal energy by at least 15€/MWh, while it becomes an attractive investment for an increase in the order of 50% compared to the present levels (18€/MWh), demonstrating a high IRR (17%) and a ten-year payback period. The net present value after 20 years approaches 40% of the initial investment cost. For an increase in the selling price of thermal energy by 30 €/MWh, the final cost for the consumer remains in the order of 80% compared to the respective cost of heating oil, while the financial results of the investment are particularly attractive, since the IRR reaches 75%, the payback period equals 5 years and the net present value after 20 years amounts to 200% of the initial investment cost.

Table 3.4: Economic characteristics of the investment for a fixed supply price of biomass (90 €/tn) and a variable selling price of thermal energy in Scenario 1 (*approach B*).

Variation in the selling price of thermal energy (€/MWh)	NPV (€)	IRR (%)	Paybak period (years)
0	-33,438,922	-	-
+15.20	0.68	4.0	19.86
+18.00	8,050,983.63	17.2	10.05
+21.00	16,668,436.04	32.8	6.56
+24.00	25,285,888.45	49.5	4.80
+27.00	32,823,052.25	62.2	4.05
+30.00	40,330,738.43	74.9	3.41

3.2. Scenario 2: CHP with biogas, solar thermal systems with seasonal store-heat pumps and biomass boilers.

This scenario examines whether the financial performance and final cost for the consumer can be improved, if in addition to the biomass boiler in Scenario 1, part of the thermal needs will be covered by a CHP-biogas unit and the use of thermal solar systems with seasonal store and heat pumps. This choice reduces the necessary biomass boiler capacity and increases the initial investment cost, but it provides supplementary income from the sales of the electricity generated by the CHP with biogas. The characteristics and data used for the calculations needs of this scenario are listed on the table below.

Table 3.5: Technico-Economic Characteristics for Scenario 2

Biogas	Unit installation capacity	1.02 MW_{el}, and 1.22 MW_{th}
	Electricity sold	8.39 GWh/year
	Heat generated	9.67 GWh/year
	Heat sold	6.77 GWh/year
Thermal Solar Systems and Seasonal Store	Thermal Solar Systems Surface	15,000 m^2
	Thermal Solar Systems Power	10 GW
	Seasonal Store Volume	40,000 m^3
	Heat pumps' capacity	2 MWel
	Heat sold	38 GWh/year
Biomass Boilers	Unit installation capacity	50 MW_{th}
	Heat sold	165.23 GWh/year
Fuel Consumption	Electricity	10.56 GWh/year
	Biomass Fuel	36,718 tons/year
Energy generation	Electricity Sold	8.39 GWh/year
	Heat Sold	210 GWh/year
Expenses	Installation cost	24.980.000 €
	Operation and maintenance cost (except for the biomass cost)	2.971.000 €/year

Tables 3.6 and 3.7 show the economic analysis results. The improvement compared to Scenario 1 is marginal, since the contribution to income from the CHP unit with biogas is practically offset by the extra cost of the initial investment and the higher operation and maintenance cost.

Table 3.6: Variation in the selling price of thermal energy compared to the biomass supply price for zero NPV (*approach A*) for Scenario 2.

Biomass supply cost (€/tn)	Variation in the selling price of thermal energy (€/MWh)
70	+10.02
80	+11.75
90	+13.47
100	+15.19
110	+16.92
120	+18.64
130	+20.37
140	+22.09
150	+23.81

Table 3.7: Economic characteristics of the investment for a fixedsupply price of biomass (90 €/tn) and a variable selling price of thermal energy in Scenario 2 (*approach B)*.

Variation in the selling price of thermal energy (€/MWh)	NPV (€)	IRR (%)	Paybak period (years)
0	-43,056,227.66	-	-
+16.08	7,959,990.51	11.9	12.32
+18.00	12,408,318.59	16.5	10.17
+21.00	21,008,972.60	25.2	7.62
+24.00	29,850,784.60	33.5	6.18
+27.00	38,498,542.30	43.0	5.11
+30.00	47,120,690.09	53.5	4.29

3.3. Scenario 3: Biomass boilers and CHP-ORC

Despite the positive impact of electricity generation from CHP with biogas on the financial performance of Scenario 2, the possibility of biogas contribution (from the specific sources examined) in order to meet the thermal needs of the DH network is limited. Given that the solid biomass does not have the same limitations, this scenario examined the combination of biomass boilers with CHP-ORC units. The biomass boilers are assumed to operate only during the heating period, and the CHP–ORC unit throughout the year. In order to dimensionalize the system, the maximum possible electrical power ($5MW_{el}$) of the combined production unit was assumed, which ensures the highest guaranteed price (170€/MWh), while the remaining thermal needs are covered by biomass boilers. The characteristics and data used for the calculations are listed on the table below:

Table 3.8: Technico-Economic Characteristics for Scenario 3

CHP-ORC with biomass	Unit installation power	5 MW_{el} and 20 MW_{th}
	Electricity Sold	40 GWh/year
	Heat generated	158.34 GWh/year
	Heat Sold	118.75 GWh/year
Biomass Boilers	Unit installation power	40 MW_{th}
	Heat Sold	91.25 GWh/year
Fuel Consumption	Biomass Fuel	67,456 tons/year
Energy Generation	Electricity Sold	40 GWh/year
	Heat Sold	210 GWh/year
Expenses	Installation cost	36,125,000 €
	Operation and maintenance cost (except for the biomass cost)	1,330,400 €/year

Tables 3.9 and 3.10 show the economic analysis results of Scenario 3. Despite the significant increase in the initial investment cost compared to Scenarios 1 and 2, Scenario 3 shows a major improvement in the economic characteristics, since the low supply prices for biomass (70-90 €/tn) require a minimal to zero increase in the selling price of thermal energy compared to the present levels in order to make the investment marginally viable (zero NPV after 20 years). We also note the significant IRR of 12%, the drop in the the payback period to 12.5 years and the high NPV after 20 years which is over 50% of the initial investment, for only a small increase -of the order of 16% (6.19€/MWh)- in the selling price of thermal energy.

Table 3.9: Variation in the selling price of thermal energy compared to the biomass supply price for zero NPV (*approach A*) for Scenario 3.

Biomass supply Cost (€/tn)	**Variation in the selling price of thermal energy (€/MWh)**
70	+0.26
80	+2.81
90	+5.36
100	+8.32
110	+11.65
120	+14.98
130	+18.31
140	+21.64
150	+24.97

Table 3.10: Economic characteristics of the investment for a fixed supply price of biomass (90 €/tn) and a variable selling price of thermal energy in Scenario 3 (*approach B*).

Variation in the selling price of thermal energy (€/MWh)	**NPV (€)**	**IRR (%)**	**Paybak period (years)**
0	-20,685,705	-	-
+6.19	14,949,858.89	11.8	12.17
+9.00	24,544,170.94	17.0	9.55
+12.00	33,997,867.55	22.3	8.05

+15.00	41,988,571.54	26.8	7.09
+18.00	49,979,278.20	31.2	6.32
+21.00	57,517,542.93	35.3	5.71
+24.00	64,766,491.11	39.0	5.32
+27.00	72,015,441.70	42.7	4.85
+30.00	79,264,389.88	46.4	4.56

3.4. Scenario 4: CHP-ORC.

Given the improvement of the economic characteristics in Scenario 3 compared to Scenarios 1 and 2 that did not include CHP-ORC units, this scenario examines the possibility to meet the total thermal needs of the DH network exclusively with CHP–ORC units. This selection is characterized by the need for larger capacity in order to meet the total thermal needs, which leads to a reduced FiT for the generated electricity compared to Scenario 3 (148 €/MWh vs 170 €/MWh), while at the same time the initial investment cost significantly increases, as well as the annual operation and maintenance costs. On the negative side however, this scenario has the highest needs in terms of biomass compared to the remaining scenarios that will be presented next. The characteristics and data used for the economic analysis of Scenario 4 are listed on the table below.

Table 3.11: Technico-Economic characteristics for Scenario 4.

CHP-ORC with biomass	Unit installation power	8.84 MW_{el} and 35.36 MW_{th}
Fuel Consumption	Biomass Fuel	83,350 tons/year
Energy Generation	Electricity Sold	70 GWh/year
	Heat generated	280 GWh/year
	Heat Sold	210 GWh/year
Expenses	Installation cost	42,269,000 €
	Operation and Maintenance Cost (except for the biomass cost)	1,725,766 €/year

The economic analysis results of Scenario 4 are listed on Tables 3.12 and 3.13. Despite the higher initial investment cost and the high operating expenses, meeting the heat needs from CHP units leads to a decrease in the selling price of thermal energy compared to the present levels for biomass supply prices of almost up to 100 €/tn (approach A). In fact, for a price of 70 €/tn, the reduction in the selling price exceeds 18% (6.93 €/MWh). Even in case the biomass cost amounts to 150 €/tn, the sales cost of thermal energy to the final consumer remains significantly lower than the oil cost and reaches up to approximately 70% thereof.

Table 3.12: Variation in the selling price of thermal energy compared to the biomass supply price for zero NPV (*approach A*) for Scenario 4.

Biomass supply cost (€/tn)	Variation in the selling price of thermal energy (€/MWh)
70	-6.93
80	-4.19
90	-1.46
100	+1.86
110	+5.83
120	+9.79
130	+13.76

140	+17.73
150	+21.70

The financial performance of Scenario 4 is extremely attractive in terms of investment as well (*approach B*). For a fixed supply price of biomass, equal to the reference price (90 €/tn), and by maintaining the selling price of thermal energy at the present levels, an IRR of the order of 6.2% is achieved, as well as a payback period of about 16.68 years, while the net present value after 20 years is close to 15% of the initial investment cost. For an increase in the selling price of thermal energy by only 6 €/MWh, the respective figures show a much greater improvement. Finally, it is noted that due to the operation of the system throughout the year, there is excess heat that is generated during the summer, which cannot be utilized commercially. However, if thermal uses during the summer period can be found and applied, the economic results of the investment can be improved even further to the consumers' benefit.

Table 3.13: Economic characteristics of the investment for a fixed supply price of biomass (90 €/tn) and a variable selling price of thermal energy in Scenario 4 (*approach B*).

Variation in the selling price of thermal energy (€/MWh)	NPV (€)	IRR (%)	Paybak Period (years)
0.00	6,227,257.00	6.2	16.68
+3.00	14,844,709.02	9.5	13.55
+6.00	23,303,966.75	12.8	11.37
+9.00	31,921,419.16	16.2	9.70
+12.00	40,538,871.57	19.7	8.58
+15.00	49,156,323.98	23.2	7.67
+18.00	57,327,574.16	26.4	7.03
+21.00	64,835,260.34	29.1	6.50
+24.00	72,342,946.52	31.8	6.11
+27.00	79,850,632.70	34.6	5.65
+30.00	87,358,318.89	37.3	5.36

3.5. Scenario 5: CHP with biogas, solar thermal systems with seasonal store-heat pumps and CHP-ORC units.

The main disadvantage in fully meeting the thermal needs of the DH network exclusively from CHP-ORC units is the large quantities of biomass required each year. In order to reduce this dependence, Scenario 5 examined the possibility to meet the thermal needs from CHP with biogas and solar thermal systems from CHP with biogas and solar thermal systems with seasonal store and heat pumps. The maximum possible contribution of CHP with biogas was assumed, based on the specific sources of biogas that were examined (see section 2.1). The solar thermal system was dimensioned exactly in the same way as in section 2.2.1 and the remaining thermal needs were assumed to be met by the CHP–ORC units. The characteristics and data used for the economic analysis are listed in the table below.

A significant decrease in the needs for biomass is observed compared to Scenario 4, of the order of 22%, but due to the small contribution of biogas and solar thermal systems in addressing thermal needs, the necessary power of the CHP-ORC units exceeds 5 MW_{el}; therefore, the electricity is sold with the lowest FiT of 148 €/MWh. In addition, the initial investment cost remains at the same levels as those of Scenario 4; However, a significant increase in the annual operation and maintenance costs is observed.

Table 3.14: Technico-Economic Characteristics for Scenario 5.

Biogas	Unit installation power	1.02 MWel and 1.22 MWth
	Electricity Sold	8.39 GWh/year
	Heat generated	9.67 GWh/year
	Heat Sold	6.77 GWh/year
Thermal Solar Systems and Seasonal Store	Thermal Solar Systems Surface	15,000 m2
	Thermal Solar Systems Power	10 GW
	Seasonal Store Volume	40,000 m3
	Installation power of heat pumps	2 MWel
	Heat Sold	38 GWh/year
CHP-ORC with biomass	Unit installation power	6.86 MW_{el} and 27.43 MW_{th}
	Electricity Sold	54.33 GWh/year
	Heat generated	216.23 GWh/year
	Heat Sold	166 GWh/year
Fuel Consumption	Electricity	10.56 GWh/year
	Biomass Fuel	64659 tons/year
Energy Generation	Electricity	54.33 GWh/year
	Heat	210 GWh/year
Expenses	Installation cost	42,381,688 €
	Operation and Maintenance Cost (except for the biomass cost)	3,697,223 €/year

Tables 3.15 and 3.16 demonstrate that the economic characteristics of Scenario 5 are attractive both for the consumer and for the investor. It is noted that the for a marginal viability of the investment (approach A) and for a biomass supply cost of up to almost 90 €/tn, even a reduction in the selling price of thermal energy may be achieved compared to the present levels.

Table 3.15: Variation in the selling price of thermal energy compared to the biomass supply price for zero NPV (*approach A*) for Scenario 5.

Biomass supply cost (€/tn)	Variation in the selling price of thermal energy (€/MWh)
70	-4.28
80	-2.03
90	+0.21
100	+2.86
110	+6.13
120	+9.39
130	+12.65
140	+15.91
150	+19.17

Moreover, for a fixed biomass supply cost (90 €/tn), even for a zero increase in the selling price of thermal energy, the investment demonstrates an IRR of the order of 3.5% and a payback period of about 20.35 years, while the net present value after 20 years is negative with marginal losses of the order of 670,000 € (1.5% of the initial investment cost). To prevent any losses, the selling price of thermal energy must be marginally increased by 0.17 €/MWh.

Table 3.16: Economic characteristics of the investment for a fixed supply price of biomass (90 €/tn) and a variable selling price of thermal energy in Scenario 5 (*approach B*).

Variation in the selling price of thermal energy (€/MWh)	NPV (€)	IRR (%)	Paybak period (years)
0.00	-668,703	3.5	20.35
3.00	11,107,290	8.3	14.57
6.00	22,483,320.46	12.6	11.45
9.00	32,475,753.71	16.2	9.67
12.00	41,659,879.14	19.7	8.52
15.00	49,880,884.22	23.1	7.61
18.00	58,101,894.78	26.6	6.84
21.00	66,322,899.86	30.2	6.30
24.00	74,543,910.42	33.8	5.73
27.00	81,904,123.42	36.8	5.41
30.00	89,109,803.78	39.5	5.14

The financial performance of Scenario 5 is slightly worse compared to that of exclusively meeting thermal needs from CHP-ORC units (Scenario 4). This performance is attributed to a significant increase in the annual operation and maintenance cost compared to Scenario 4, in combination with the reduced FiT of the generated electricity due to a demand for electrical power over 5 MW_{el}.

3.6. Scenario 6: CHP with biogas, solar thermal systems with seasonal store-heat pumps, biomass boilers and CHP-ORC units.

This scenario examines the combined application of all the proposed RES technologies, aiming at meeting the thermal needs of the DH network. This research aims at the optimum environmental, technical and economic results, creating a RES technologies mix that allows for greater flexibility and a broader availability of energy sources. It was assumed that the CHP unit with biogas utilizes all the available capacity (see 2.1.), while the dimensionalization of the solar thermal system was carried out exactly in the same way as in section 2.2.1. The remaining load is covered, in order of priority, by the CHP–ORC units; a value of 5 MW_{el} was assumed for the electrical power, in order to ensure the highest guaranteed price of 170 €/MWh. The biomass boilers cover any remaining load, as well as the needs of the peak loads together with the thermal energy stores. Specifically, the characteristics and data used for the economic analysis of Scenario 6 are listed in the table below.

Table 3.17: Technico-Economic Characteristics for Scenario 6

Biogas	Unit installation power	1.02 MW_{el} and 1.22 MW_{th}
	Electricity Sold	8.39 GWh/year
	Heat generated	9.67 GWh/year

	Heat Sold	6.77 GWh/year
Thermal Solar Systems and Seasonal Store	Thermal Solar Systems Surface	15,000 m^2
	Thermal Solar Systems Power	10 GW
	Seasonal Store Volume	40,000 m^3
	Installation power of heat pumps	2 MW_{el}
	Heat Sold	38 GWh/year
Biomass Boilers	Unit installation power	30 MW_{th}
	Heat Sold	43.98 GWh/year
CHP-ORC with biomass	Unit installation power	5 MW_{el} and 20 MW_{th}
	Electricity Sold	39.27 GWh/year
	Heat generated	158.54 GWh/year
	Heat Sold	121.25 GWh/year
Total Fuel Consumption	Electricity	10.56 GWh/year
	Biomass Fuel	56961 tons/year
Total Energy Sold	Electricity	47.66 GWh/year
	Heat	210 GWh/year
Expenses	Installation cost	42,581,375 €
	Operation and Maintenance Cost (except for the biomass cost)	3,598,000 €/year

Table 3.18 shows the necessary modification in the selling price of thermal energy for different biomass supply prices and for a zero net present value of the investment (NPV=0). It is noted that for biomass supply prices lower than the reference price (90 €/tn), it is possible to achieve even a reduction in the selling price compared to the present levels. Moreover, even for biomass supply prices close to that of the industrial briquette (150 €/tn), the sales cost of thermal energy to the final consumer remains significantly lower than the oil cost and reaches up to approximately 65% thereof.

Table 3.18. Variation in the selling price of thermal energy compared to the biomass supply price for zero NPV (*approach A*) for Scenario 6.

Biomass Supply Cost (€/tn)	Variation in the Selling Price of Thermal Energy (€/MWh)
70	-2.84
80	-0.71
90	+1.42
100	+3.54
110	+5.67
120	+8.23
130	+11.14
140	+14.05
150	+16.96

Assuming a fixedbiomass supply price (90 €/tn), it is possible to study the economic characteristics of the investment as a function of the selling price of thermal energy. The results listed on Table 3.19 show that small increases (of the order of 20%, or less than 8 €/MWh) in the selling price of thermal energy achieve very attractive financial performance with an IRR of 14.5%, a payback period of approximately 10 years and a net present value after 20 years close to 50% of the initial investment cost. For an increase in the selling price of thermal energy by 30 €/MWh, the final cost for the consumer remains in the order of 80% compared to the respective cost of heating with oil, while the financial results of the investment are particularly attractive, with an IRR of the order of 44%, a payback period of approximately 5 years and a net present value after 20 years over 200% of the initial investment cost.

Table 3.19: Economic characteristics of the investment for a fixed supply price of biomass (90 €/tn) and a variable selling price of thermal energy in Scenario 6 (*approach B*).

Variation in the selling price of thermal energy (€/MWh)	NPV (€)	IRR (%)	Payback Period (years)
0	-7,277,715	0	-
+7.82	23,797,001.79	14.5	10.56
+9.00	27,032,512.90	16.0	10.04
+12.00	36,823,326.21	20.3	8.53
+15.00	47,355,813.80	25.2	7.37
+18.00	57,468,280.51	29.6	6.50
+21.00	66,182,765.07	33.4	5.85
+24.00	74,089,567.06	37.3	5.44
+27.00	81,682,850.09	40.9	5.11
+30.00	88,719,036.86	43.9	4.72

The addition of a biomass boiler in this scenario maintains the investment cost and the annual operation and maintenance cost at the same levels as those of Scenario 5, but it reduces the generated electricity and, eventually, the income from electricity sales despite the increased FiT. As a result, the financial performance of Scenario 6 is slightly worse than that of Scenario 5. On the other hand, the use of biomass boilers leads to a significant decrease in the annual needs for biomass (by 12% compared to Scenario 5 and by 32% compared to Scenario 4).

3.7. Comparative Analysis of Results

Figure 3.1 shows the accumulative results, for all the scenarios, concerning the variations in the selling price of thermal energy as a function of the fuel cost, aiming at minimizing the cost for the consumer, namely for zero net present value after 20 years (approach A); Figure 3.2. shows the IRR for all the scenarios as a function of the variation in the selling price of thermal energy for a fixed biomass supply price that equals the reference price (90 €/tn) (approach B).

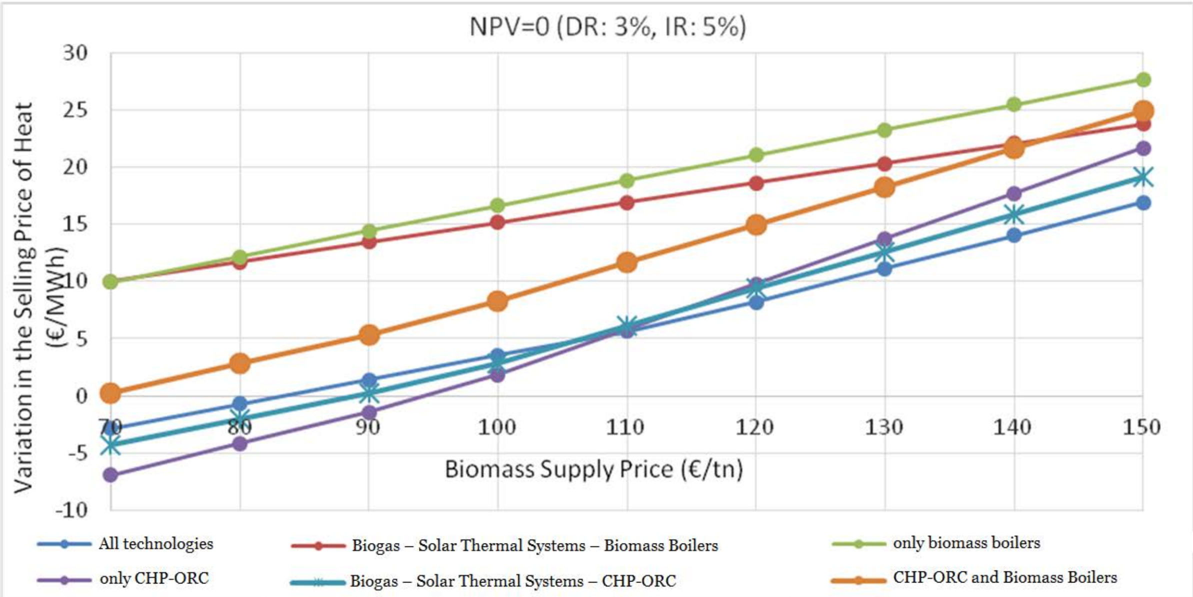


Figure 3.1: Variation in the selling price of thermal energy compared to the biomass supply price for zero NPV, a discount price of 3% and an interest rate of 5% for Scenarios 1-6.

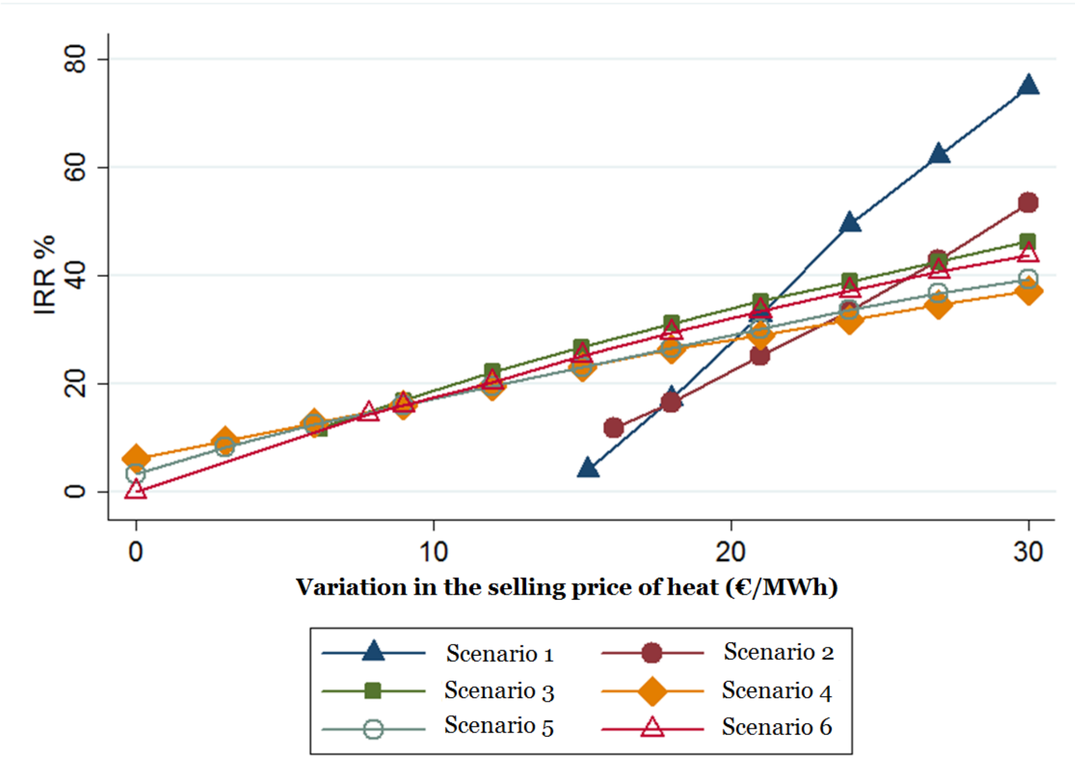


Figure 3.2: IRR for various selling prices of thermal energy, for a biomass supply price of 90 €/tn

It is clear that Scenarios 4, 5 and 6 that include the CHP-ORC units demonstrate the optimum economic results in terms of the final cost for the consumer (Figure 3.1) due to the significant contribution of electricity generation to the income.

The scenarios which are mainly based on the biomass boilers (Scenarios 1-3) show a higher IRR only for increases in the selling price of thermal energy that exceed 20 €/MWh (Figure 3.2). Thus, while the initial investment cost of Scenarios 1-3 is significantly lower, their financial performance is still clearly worse than that of the Scenarios based on CHP-ORC units.

The scenario with the best, overall, financial performance is the one where the DH needs are exclusively met by CHP-ORC units (Scenario 4). A zero investment profit (zero net present value after 20 years) achieves a reduction in the selling price of thermal energy by up to almost 7€/MWh (Figure 3.1), while the scenario of a zero increase in the selling price of thermal energy for the consumers achieves the best IRR (6.2%) for a biomass supply cost of 90 €/tn (Figure 3.2). However, this solution includes the highest annual fuel needs. Since Scenarios 5 and 6, which also include other renewable energy sources in the district heating mix, show similar financial performances and a very similar initial investment cost, while at the same time requiring much smaller quantities of biomass, we consider them preferable alternative solutions.

The main values selected for the discount price and the interest rate (DR=3% and IR=5%, respectively) are characteristic of a smooth market which does not reflect the present conditions in Greece. In order to examine the sensitivity of the solutions under these conditions, an economic analysis of 6 scenarios was carried out with DR=6% and IR=8%, values characteristic of more aggressive investments under more unstable market conditions. The results are shown on Figure 3.3 and they demonstrate small quantitative differences compared to the basic calculations.

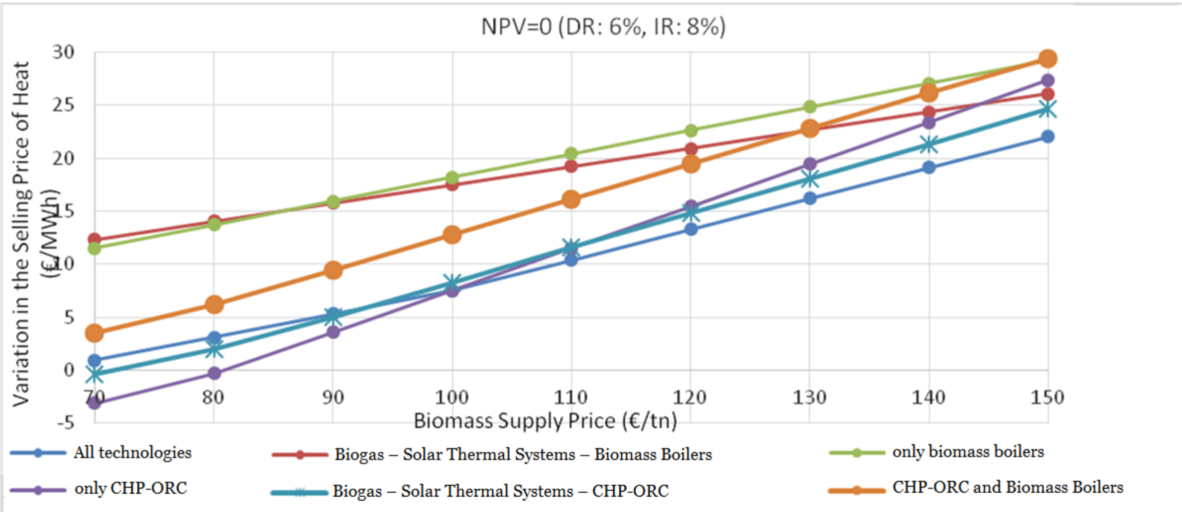


Figure 3.3: Variation in the selling price of thermal energy compared to the biomass supply price for zero NPV, a discount price of 3% and an interest rate of 5% for Scenarios 1-6.

In any case, the economic analyses of the three best scenarios (4, 5 and 6) demonstrate similar results. The final technological solutions must be based on multiple parameters, in addition to the financial ones, such as fuel availability and cost, the exact dimensionalization of facilities based on the possibilities for the maximum utilization of the generated energy (possibilities of extension to applications of district cooling and thermal energy distribution for industrial and handicraft uses, etc.), the pricing policy (social or business), the environmental footprint, etc.

4. Conclusions

In conclusion, the alternative solutions based on the combined production of power and heat with ORC units offer economically viable competitive selling prices of thermal energy for the consumers, provided the biomass supply price does not exceed 90-100 €/tn. These price levels are deemed feasible, given that the wood chips and the biomass from energy crops (cardoon) range around 70 €/ton with delivery at the combustion unit. Taking into account that the supply price of the industrial briquette does not exceed 150 €/ton, in order to achieve an average biomass supply price of 90 €/ton, there will be a fuel ratio of about 75% from wood chips and 25% from briquettes, which is deemed reasonable for the biomass quantities (40,000-70,000 tons/year) required for the operation of the proposed systems.

In any case, all the proposed scenarios achieve much better thermal energy supply prices than those of oil, utilizing at the same time the available RES capacity and reducing the environmental load, such as, for example, methane release from organic waste. In case it is possible to utilize the generated thermal energy throughout the whole year, the financial results from the operation of the proposed systems will be further improved.

In addition, it is worth noticing that once the proposed solutions are applied, parallel activities can be developed, such as the installation of hydroponic greenhouse units for the development and exploitation of various agricultural products, such as algae, gardening products (tomato, lettuce, etc.) and others. In this way, additional income is generated, which can be utilized in order to subsidize the selling price of thermal energy. Moreover, the application of systems such as the proposed ones can facilitate the development of new professional activities and jobs, with major social, and environmental, secondary financial results; however this research does not fall under the scope of the present study.

Therefore, it is made clear that the dilemma "lignite or oil", with regards to meeting the thermal needs of the DH network, ceases to exist, since there are economically viable competitive alternatives based on RES, which must be examined comparatively in the future plans of district heating systems in the region of Western Macedonia.

Annex: Local Partnerships

Many of the jobs related to the development of RES in order to meet the energy needs in various European countries (see section 1.5) are created by energy community cooperatives, aiming at and focusing on the development of financial activities that utilize RES in the financial and environmental interest of local societies.

The most frequently met frameworks involve agricultural or forest cooperatives that manage or develop forest or energy crops with the optimum, environmentally friendly practices, in order to utilize them to meet primarily the energy needs of local communities. In this way, there are direct or indirect financial benefits either by selling RES energy products or by utilizing them in order to reduce the energy cost. In many cases, due to the activation of energy community cooperatives, various communities that had started to shrink due to the lack of professional opportunities, began to re-develop and new high level jobs started to emerge; their results often form the object of academic and research activities.

Nowadays, various networks of such communities have been developed, which aim at the exchange of experiences, the coordination of actions and their mutual support. A characteristic example is the European Federation of Renewable Energy Cooperatives. The energy cooperatives do not necessarily fall under the legal status of cooperatives, but stand out from the way they do business. They comply with 7 characteristic principles of the International Cooperative Alliance[48]:

- Volunteering and open participation
- Democratic control of the members
- Financial participation and direct ownership
- Autonomy and independence
- Education, training and information
- Cooperation between cooperatives
- Interest in community actions

In the region of Western Macedonia, an interesting initiative towards this direction is the Bio-energy and Environment Cluster of Western Macedonia[49] (Clu.BE). CluBe aims at promoting the Research & Development, as well as business activities in the sectors of bio-energy and environment, in order to support the "green" economy in the Western Macedonia and the nearby area.

Cooperative frameworks, according to European standards, could also be established in the city of Ptolemaida in the interest of its citizens. For example, the agricultural cooperatives in the area could be involved in the sector of energy crops. Moreover, other investment opportunities could also be developed in the sector of hydroponics for the production of high quality agricultural products or for the cultivation of algae, utilizing the processes and by-products of both the biogas unit and the energy generation stations. Out of these by-products, the carbon dioxide and the liquid fertilizer which contains ammonia can be used as "food" in order to develop hydroponic crops or to produce either garden products or algae.

Indicatively, it is noted that the management of 10,000 m^3 of stockbreeding waste, through the process of anaerobic digestion, and the combustion of the generated biogas may lead to the production of 160 tons of algae in a hydroponic greenhouse with a surface of 10,000 m^2. The cost of such an investment approaches €2 million, while the operational cost of such a unit amounts to almost 30% of the investment cost. If spirulina crops are selected (average selling price: 10 €/kg), the annual income can amount to €1.6 million with a net profit before tax and amortization of the order of €1 million. Based on the above, the simple payback

[48] ResCoop.eu. "What is a Resccop?" https://goo.gl/ThQuB8
[49] Bio-energy and Environment Cluster of Western Macedonia http://goo.gl/zJc9dn

period for the investment is approximately 2 years, or 4-5 years including taxes, amortization and the cost of money.

Other alternative crops instead of algae could be garden products, such as tomato, lettuce, etc. In this case, the investment cost amounts to €1 million for a hydroponic greenhouse of 10,000 m². The operational cost of such a unit amounts to approximately 28% of the investment cost. The yield per 1000 m² for tomatoes is close to 50 tons/year. For an average wholesale price of 1.2 €/kg, the annual income amounts to €600,000, while the net profit before taxes and amortization will be of the order of €320,000 annually. With the above assumptions, the simple payback period for the investment is approximately 3.5-4 years, or 5-6 years including taxes, amortization and the cost of money.

Based on the quantities of stockbreeding waste and biological treatment that were taken into account in this study, a greenhouse unit could be constructed of the order of 50,000 m², which would require investments of €5-20 million with a net profit before taxes and amortizations amounting to €1.45-5 milion. annually. An indicative economic analysis of the investment's life cycle for a hydroponic greenhouse unit of the order of 50,000 m² is presented below, where tomatoes will be cultivated, with the following assumptions:

Greenhouse	Surface	50,000 m²
Production	Tomatoes (tons/year)	250
Expenses	Installation cost (€)	5,500,000
	Operation and Maintenance Cost (€/year)	1,540,000
Income	Income from tomatoes sales (€/year)	3,000,000

The investment's preliminary analysis assumed that it will be possible to cover 40% by subsidization, 40% by loans and the remaining 20% by own capital, while the discount rate (DR) and interest rate (IR) was assumed to be 3% and 5% respectively. The results of the analysis are presented on the following graph:

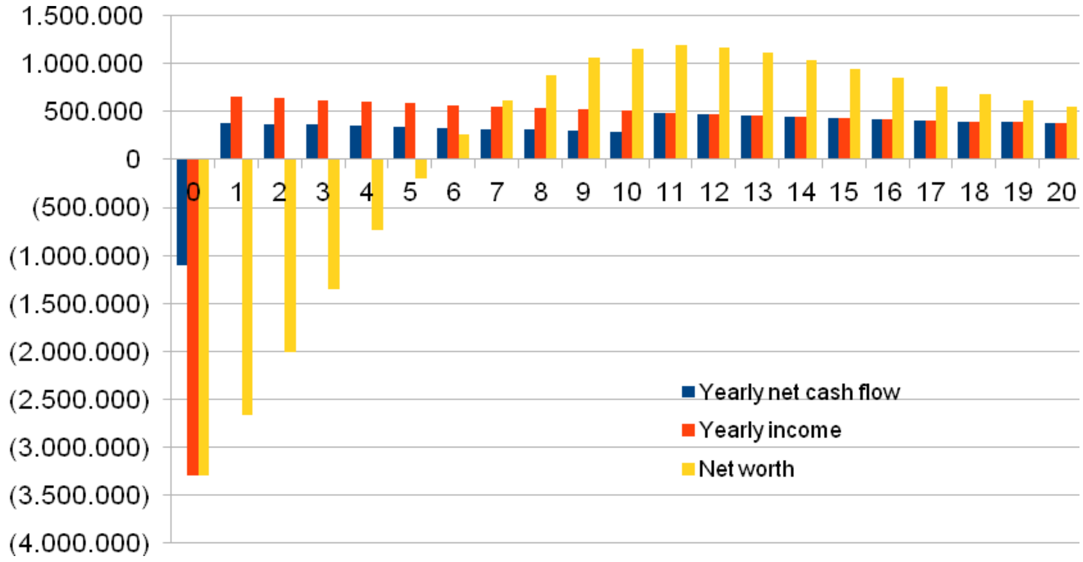


Figure A1: Economic analysis of the investment on a hydroponic greenhouse unit

With the above assumptions, the implementation of the proposed investment is advantageous, since it achieves the following:

- IRR on own capital: 16.2%,
- NPV over 20 years: 4,616,683 Euros
- Cost-benefit ratio: 1.16 and
- Discounted Payback Period: 5.84 years.

The financial benefits from the operation of the hydroponic greenhouse unit could be utilized in the interest of the shareholders-inhabitants of the area, either to cover the cost of energy investments, as long as these are carried out gradually, or to reduce the selling price of thermal energy in the district heating network or as a purely financial profit yielded to the shareholders of the cooperative.

Moreover, the development of these activities may create additional business activities, such as stockbreeding and handicraft (processing and standardization of agricultural and stockbreeding products), which besides their obvious benefits, can generate heating and cooling loads during the summer and, therefore, improve the financial efficiency of energy investments due to the sales of thermal energy which would otherwise be rejected during the summer period by the CHP units.

These investments have not only a financial benefit but also other significant environmental and social benefits. In fact, due to the utilization of carbon dioxide for the cultivation of algae or garden products, a respective reduction in CO_2 emissions from the combustion units is achieved, while 7-10 permanent jobs are created per 10,000 m^2 of a hydroponic greenhouse unit, in addition to the seasonal jobs and those to be created during the construction phase of the projects.

The implementation of the above can create a different sustainable model for local development which can offset the direct and indirect impact from the expected gradual closing down of PPC's lignite power stations.

"We shan't save all we should like to – but we shall save a great deal more than if we never tried."

Sir Peter Scott, founding chairman of the World Wildlife Fund (WWF)

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