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MINISTRY OF COMMERCE, INDUSTRY AND TOURISM

ENERGY SERVICE

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ASSESSMENT OF NATIONAL POTENTIAL FOR COGENERATION IN CYPRUS

FINAL REPORT

TASK FORCE

CRES (CENTRE FOR RENEWABLE ENERGY SOURCES, GREECE)

EXERGIA, GREECE

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1 ENERGY POLICY IN CYPRUS

1.1 General Information

Cyprus lies in the eastern part of the Mediterranean, south of Turkey. It has a total surface area of 9,250 km^2 and its coastline is 648 km long. Cyprus's morphology is marked by plains in its central regions, with mountains in the north and south, and interrupted stretches of plains in its southern parts. The island's highest altitude is 1,951 m. It faces water shortage problems due to seasonal rainfall disparities, seawater penetration into the island's water table and the absence of natural water retention areas.
In 2005, Cyprus had an estimated population of 749,000 inhabitants (based on the last census poll taken in 2001, Cyprus has 689,565 inhabitants), while it is expected to have 975,000 inhabitants by 2050, making it one of the few EU countries expecting a population increase in the future.
Cyprus has approximately 193,000 households, the average household size being 3.06 people in 2001.

1.2 State of the Cypriot Economy

Cyprus joined the European Union in 2004 and adopted the euro in early 2008. The economy of the Republic of Cyprus is dominated by the services sector, which represents 76% of its GDP. Tourism and financial services are the sector's major branches. Irregular growth rates noted in the last decade reflect the economy's high dependence on tourism, which fluctuates in line with the region's political stability and economic conditions in Western Europe. The Cypriot economy, nonetheless, enjoyed robust annual GDP growth of 3.7% in 2004 and 2005, which is significantly higher than the European average.

The Cypriot economy presented an overall strong economic growth in the 1995-2005 period. GDP rose by 41.3%, which, on average, corresponds to around 4% a year. There was a rise in the value added of all branches of economic activity, with the exception of the agricultural sector, which showed a 45% drop in this period. The services sector's value added rose by 18%, and given that the tertiary sector is by far the largest sector in terms of value added, it also served to stimulate economic growth. Industry's value added shrank by 20% during the same period of time and household consumption increased by 41%. Figure 1.2.1 shows the trends in GDP and value added per sector for the years 1995-2004, and Figure 1.2.2 shows the same results using an adjusted index, with 2000 as the reference year, so as to indicate more clearly relative changes among sectors.

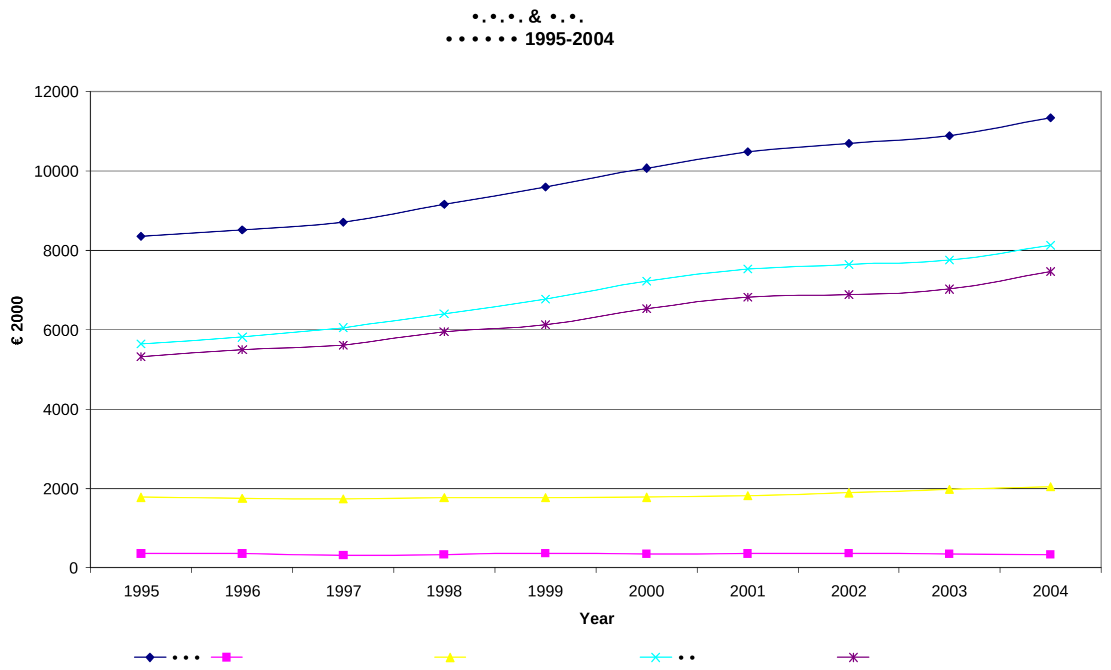


Figure 1.2.1: GDP and value added for the Cypriot economy from 1995 to 2004, using fixed 2000 prices

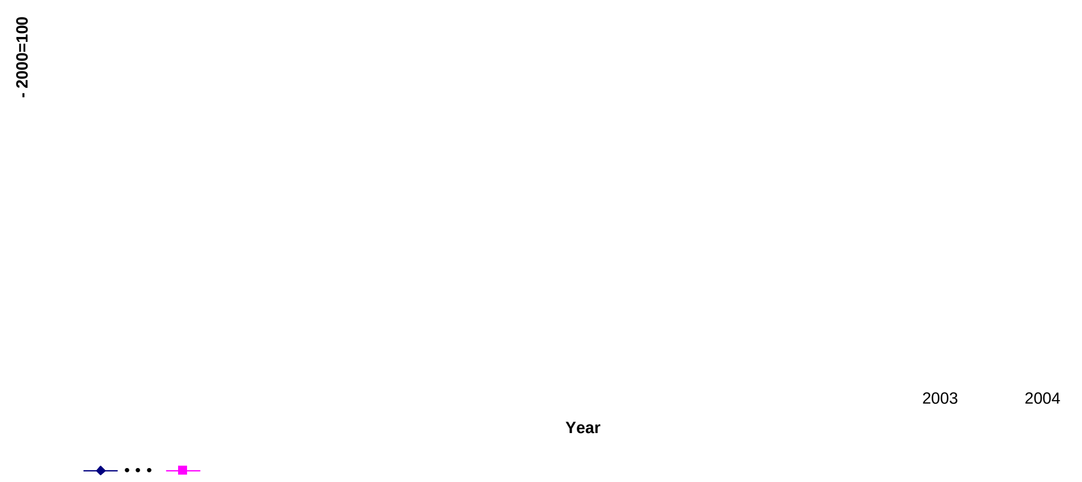


Figure 1.2.2: Trends in GDP and Value Added for Cyprus using the year 2000 as the reference year for indices

Cyprus's accession to the European Union had an adverse effect on the agricultural sector because it enabled the importation of cheaper agricultural products from EU Member States. Growth in the services sector is for the most part linked to growth in tourism. Increased industrial growth after 2001 is mainly due to the growth in the manufacturing industry and to the corresponding increase in demand by Cypriots and foreigners alike. Lastly, increased household consumption reflects the rise in household revenues and the conditions of full employment prevailing, with unemployment rates remaining below 3.6%.

In the 2004-2008 period, the Cypriot government implemented policies that aimed towards the Cypriot economy's convergence with the requirements set for it to be admitted to the eurozone.
The main objective was to reduce its financial deficit, which was 6.3% in 2003, below 3%. Having achieved its goals, Cyprus adopted the euro on 1.1.2008. This is expected to have a positive impact on the country's economy by stimulating economic growth.

1.3 National Energy and Environmental Policy

Energy policy in Cyprus is the responsibility of the Ministry of Commerce, Industry and Tourism (Energy Service). Cyprus acceded to the European Union in 2004 and has since adopted European policy on RES, energy savings and environmental protection. There were no such policies in force in Cyprus before its accession. The country's energy policy is completely in line with European energy policy, and its principal objectives are:

- Ø To secure energy supply and to meet energy demands while keeping national economic costs and environmental impact at a minimum.
- Ø To diversify energy sources by introducing liquefied natural gas (LNG).
- Ø To reduce its energy dependence and to promote productivity and competitiveness through environmentally friendly energy investments, such as RES, energy saving and cogeneration (CHP).
- Ø To ensure healthy competition by enhancing the legal framework for the deregulation of the energy market.

Implementation of these policies is carried out by means of the following measures:

- Deregulation of the electricity market by abolishing the monopoly of the Electricity Authority of Cyprus (EAC). A major development in the electricity market is the introduction of liquefied natural gas.
- Deregulation of the petroleum products sector by abolishing price control measures and cross-subsidisation of petroleum products and enforcing market regulation of prices and the indirect taxation already in force.
- Construction and operation of a petroleum product terminal.
- Construction and operation of an LNG terminal.
- Implementation of investment programmes related to the development of energy saving technologies, renewable energy sources and environmental protection.

Cyprus must make major changes towards cleaner energy forms in order to comply with the criteria set by the European Union.
The introduction of natural gas to the market is, thus, considered to be of substantial significance for Cyprus's energy sector and will have a positive impact on the Cypriot economy.

Studies on natural gas conducted in 2002 have led to the conclusion that the cheapest and safest way to transport natural gas to Cyprus is in the form of LNG via LNG carriers.

Studies have also showed that, owing to the absence of a central distribution network in Cyprus, natural gas can, in principle, only be used by electricity producers (EAC), followed by large consumers.

Natural gas will mainly be used in electricity generation with the aid of CCGT technology and will, in this manner, assist in diversifying the country's energy sources. The average electricity output today is 32%. Thermal power stations will gradually introduce the use of natural gas as a fuel in the long term. An LNG terminal will be built in Vassilikos together with a number of petroleum tanks containing strategic reserves. Through the introduction of natural gas into the energy system, the Cypriot government expects to achieve harmonisation with Directive 2003/55/EC relating to the operation of the natural gas market.

As regards RES policy, Cyprus set the goal of generating 6% of its electricity from RES by 2010 within the scope of Directive 2001/77/EC on the promotion of electricity produced from renewable energy sources. Cyprus has a high solar energy potential, a medium wind energy potential, a small biomass potential and no hydrodynamic potential owing to local weather conditions. Cyprus's national target for RES by 2020 is 13% of final energy consumption, based on the new Community Directive on RES.

Final energy consumption has increased significantly in the last decade, particularly in the transport, household and tertiary sectors. Adjusted final energy consumption intensity in Cyprus is appreciably higher than the EU 25 average. The adjusted value of the index has taken into account similar climatic conditions and the same economic, industrial and international air transport structures found in other EU Member States. Moreover, adjusted primary energy intensity is 40% above the EU 25 average.

A very important energy savings objective that Cyprus will be called upon to implement in the next few years concerns compliance with Directive 2002/91/EC on the energy performance of buildings (EPBD). The energy savings potential in buildings is significant given that there were no regulations on the energy performance of buildings before Cyprus's accession to the European Union. The implementation of EPBD is, thus, expected to yield significant results. For existing buildings, the Cypriot government has been running a multi-annual aid programme for energy saving investments.

Cyprus ratified the Kyoto Protocol on 16/7/1999, but is not subject to emissions restrictions. Nevertheless, the country fully supports the European Union's efforts to encourage the 27 Member States to set ambitious emissions restriction goals. As an EU Member State, Cyprus is subject to the obligations stipulated in the Directive on emissions trading.

The second National Allocation Plan covers the period 2008-2012 and includes a total of 13 plants (3 power stations, 2 cement factories, 8 brick manufacturing plants). The plan has been submitted to the European Commission for approval. The plan stipulates that gas permits equivalent to 35.46 million tons of CO_2 will have to be issued, of which 29.67 must be made available to the 13 plants covered by the Directive, 4.6 must be stored for new plants and 1.15 for RES.

1.4 Energy and Environmental Policy Tools for RES, CHP and Energy Saving Investments

In order to achieve higher penetration of RES, CHP and energy savings technologies in Cyprus's energy system and harmonisation of the country's energy and environmental policy with EU policy, the Ministry of Commerce, Industry and Tourism prepared an Action Plan for the promotion of RES, energy saving and CHP. The Action Plan covers the period 2002-2010 and it is based on studies conducted with the assistance of experts in the field.

The Action Plan primarily aims at:

1. Setting goals to achieve higher penetration of RES both overall and by RES category.
2. Removing barriers (institutional, legal, economic, etc.) preventing the penetration of RES, energy saving and cogeneration.
3. Introducing support mechanisms for RES, energy saving and cogeneration investments by means of capital subsidies or feed-in tariffs, so as to support electricity generation using RES and CHP.

The objectives set in the Action Plan include:

1. Doubling the share of RES in the total energy supply by 2010.
2. Increasing power generated from RES from today's zero levels to 6% by 2010.

A subsidy programme that started in 2002 and will last until 2010 grants subsidies for investments in RES, CHP and energy saving. Subsidies vary depending on the type of technology used and the type of investor involved. Thus, for large wind power projects, there is no capital subsidy but rather a fixed market price for electricity (9.23 €c/kWh) for the first five years, followed by a drop in the price in line with the wind power to be generated. Small systems are subsidised by between 40% and 55% and they are granted a fixed market price (6.32 €c/kWh). For photovoltaic systems, small investments can be subsidised up to 55%.

A duty of 0.22 €c/kWh has been imposed on all energy consumption pricing categories as of 01/08/2003. This amount is collected to create a **fund to be used to promote RES, energy saving and CHP.**

2 CYPRUS’S ENERGY SYSTEM

2.1 The Energy Supply System

Cyprus is a small island state with an isolated energy system and without any links with other European or international electricity, gas or petroleum networks. It has no domestic energy source, except for a small percentage of solar thermal systems and a very small quantity of biomass, which together do not exceed 2% of the country’s total energy consumption in 2005. Energy dependence was, consequently, 98% in 2005. From 1995 to 2005, primary energy consumption increased by 25%, rising from 1970 ktoe to 2460 ktoe. Final energy consumption during the same period increased by 28%, from 1404 ktoe in 1995 to 1809 ktoe in 2005. This rising trend stems from a large increase in electricity consumption, namely 82% (from 2180 GWh in 1995 to 3960 GWh in 2005). Petroleum product consumption increased during this time by 24%, from 1914 ktoe to 2374 Mtoe. Cyprus’s energy system does not yet make use of natural gas. RES contribute 50 ktoe from solar systems, an energy technology that is particularly widespread in Cyprus (which ranks first worldwide in the number of systems per inhabitant). Up until 2005, no power had been generated using RES in the country. Coal has a 36 ktoe share and is used in the cement industry.

Table 2.1.1: Primary Energy Supply 1995-2005 (ktoe)

Year	***1995***	***1996***	***1997***	***1998***	***1999***	***2000***	***2001***	***2002***	***2003***	***2004***	***2005***
Petroleum Products	**1914**	**2061**	**2009**	**2151**	**2198**	**2302**	**2328**	**2342**	**2553**	**2352**	**2374**
Solid Fuels	**13**	**11**	**15**	**20**	**23**	**35**	**37**	**37**	**38**	**38**	**36**
RES	**42**	**43**	**42**	**43**	**44**	**43**	**43**	**43**	**45**	**47**	**50**
Total	***1969***	***2115***	***2066***	***2214***	***2265***	***2380***	***2409***	***2422***	***2636***	***2437***	***2460***

Source: Eurostat

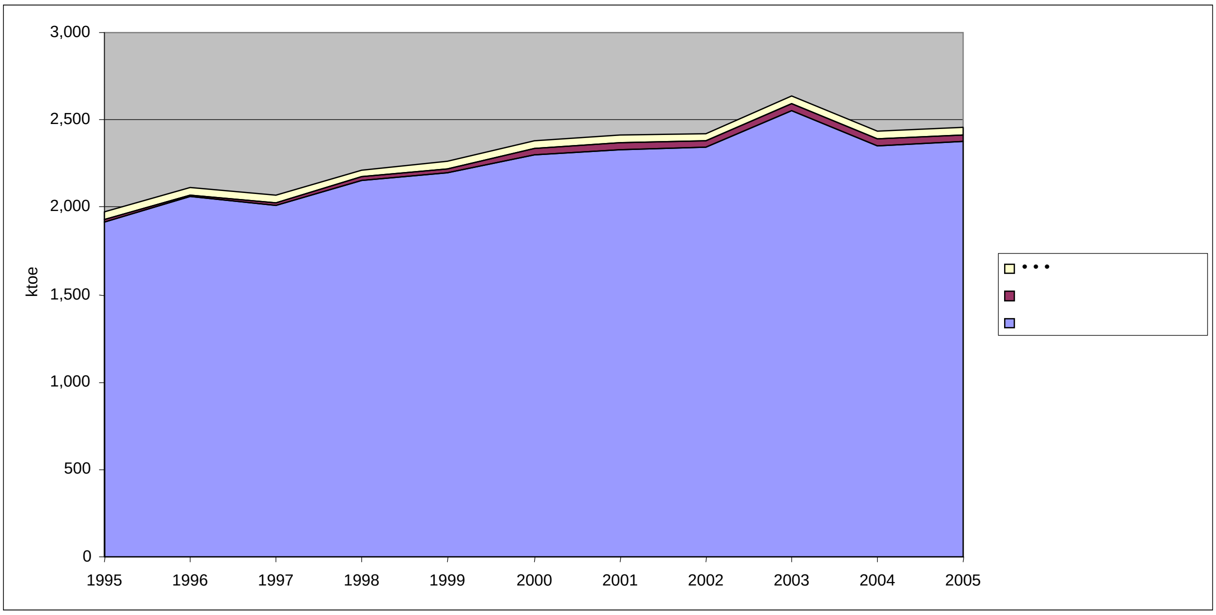


Figure 2.1.1: Primary Energy Supply 1995-2005

Table 2.1.2: Primary energy supply per fuel type, 1990 to 2005 (ktoe)

Fuel	1990	2000	2005
Bituminous Coal	60	35	30
Petroleum	1441	2300	2370
Natural Gas	-	-	-
Combined RES & Solid Waste	-	-	-
Nuclear Energy	-	-	-
Geothermal Energy	-	-	-
Solar, Wind & Tidal Energy	6	43	50
Hydroelectric Energy	-	-	-
Net Electricity Imports	-	-	-
Total	1506	2370	2460

Source: Eurostat

2.1.1 Fossil Fuels (Petroleum Products, Gas and Coal)

Cyprus has no indigenous fossil fuels whatsoever and it is entirely dependent on imported fuels. In 2005 Cyprus imported fossil fuels (almost exclusively petroleum products) with an energy content of 2.38 Mtoe, corresponding to 96% of its total primary energy supply. There are no refineries in the country and all petroleum products are imported. There are no inter-connectors linking the petroleum pipelines of Cyprus with its neighbouring countries. Limited use of imported coal is made in the cement industry (36 ktoe). The construction of an LNG terminal is being planned.

2.1.2 Electricity and Heat

Gross electricity production in Cyprus rose from 1.97 TWh in 1990 to approximately 4.4 TWh in 2005, which corresponds to a 123% increase.

All electricity is generated from petroleum-fired power plants. Cyprus's electricity transmission system consists of 66 kV and 132 kV lines. There are also 132 kV lines operating at 66 kV and a short stretch of 220 kV lines operating at 132 kV. Peak load occurs in the summer (856 MW in 2005), as is the case in all electricity systems in southern Mediterranean.

Installed capacity in 2005 was 1124 MW; 82% of the country's power stations are RFO-fired steam turbine units and the rest are diesel-oil-fired gas turbine units.

As regards final electricity consumption, the tertiary sector is the largest consumer (45% of final electricity consumption), followed by the household sector (36%), industrial plants (14%) and, lastly, the agricultural sector (5%).

2.1.3 Renewable Energy Sources

The target set in the Action Plan for RES in Cyprus is for 6% of final electricity consumption to originate from RES by 2010. A target has also been set for RES to acquire a 9% share of primary energy supply. Wind energy, solar energy and biomass are likely sources of renewable energy that may be developed in Cyprus.

According to Energy Service estimates, the country's economically exploitable wind power potential is 150-250 MW and applications for aid corresponding to 743 MW in wind power installations have already been submitted (March 2006). There are a number of regions with an average annual wind velocity of 5-6 m/s and a few regions whose average annual velocity reaches 6.5-7 m/s.

Cyprus has a high solar potential that is currently being exploited using solar systems. Cyprus ranks first worldwide in installed solar thermal systems per inhabitant based on the "Sun in Action" Report. Moreover, a high number of photovoltaic systems are expected to be installed on Cyprus in the near future.

The potential for small hydroelectric systems is very limited in Cyprus. Economically exploitable potential is estimated to be less than 1 MW, with an estimated 5-6 GWh of power generated in one year.

Where biomass is concerned, the main sources of biomass are agricultural residues, municipal solid waste and landfill gas.

Figure 2.1.3: Technically and economically exploitable electricity generation potential using RES

Source: Cyprus Institute of Energy, March 2006

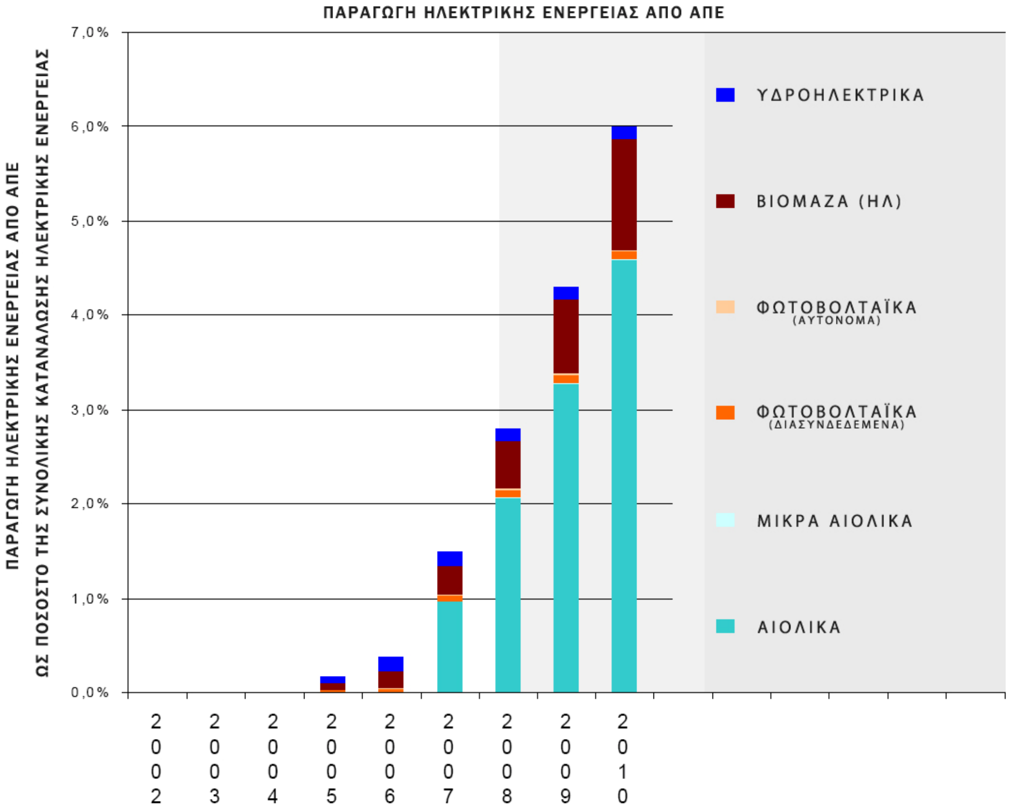


Table 2.1.2.1: Installed electricity generation capacity between 1990 and 2005 [MW]

Fuel	1990	2000	2005
Nuclear Energy	-	-	-
Conventional Fuels	480	988	1124
Lignite	-	-	-
Bituminous Coal	-	-	-
Petroleum	480	988	1124
Natural Gas	-	-	-
District Heating – Urban Gas	-	-	-
Hydroelectric energy	-	-	-
Other RES	-	-	-
Other fuels	-	-	-
Total	480	988	1124

Source: EAC

Table 2.1.2.2: Fuel used to generate electricity and net generation (ktoe, Eurostat 2005)

	Fuel used to generate electricity		Net electricity generation	
Fuel	State	Autoproducers	State	Autoproducers
Bituminous Coal				
Lignite				
Petroleum	860.0		274.7	
Natural Gas				
Nuclear Energy				
Hydroelectric Energy				
Wind Energy				
Photovoltaics				
Other				
Total	860.0		274.7	
of which CHP				

2.2 Energy Consumption

Final energy consumption in Cyprus was 1833 ktoe in 2005, having increased by approximately 66% since 1990. The breakdown of final energy consumption for the year 2005 is as follows: 23% of the energy was consumed by the industrial sector, 54% by the transport sector, and 13% and 8% by the tertiary sector and households, respectively. Tables 2.2.1 and 2.2.2 present a breakdown of final energy consumption by fuel type for the year 2005.

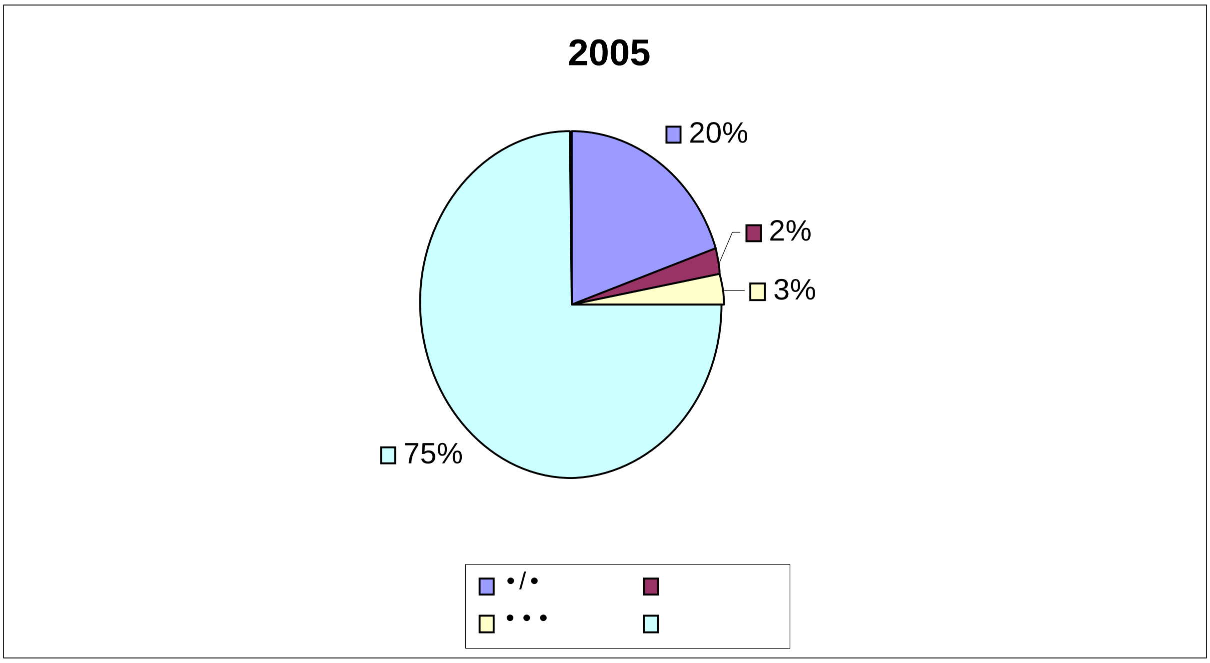


Figure 2.2.1: Final energy consumption by fuel type in Cyprus (2005)

Table 2.2.1: Final energy consumption between 1990 and 2005 [ktoe]

Fuel	1990	2000	2005
Bituminous Coal	76	35	36
Petroleum Products	855	1296	1410
Electricity	151	258	340
RES	6	43	50
Other (Methanol, Hydrogen, DME)	0	0	0
Total	1087	1633	1833

Source: Eurostat

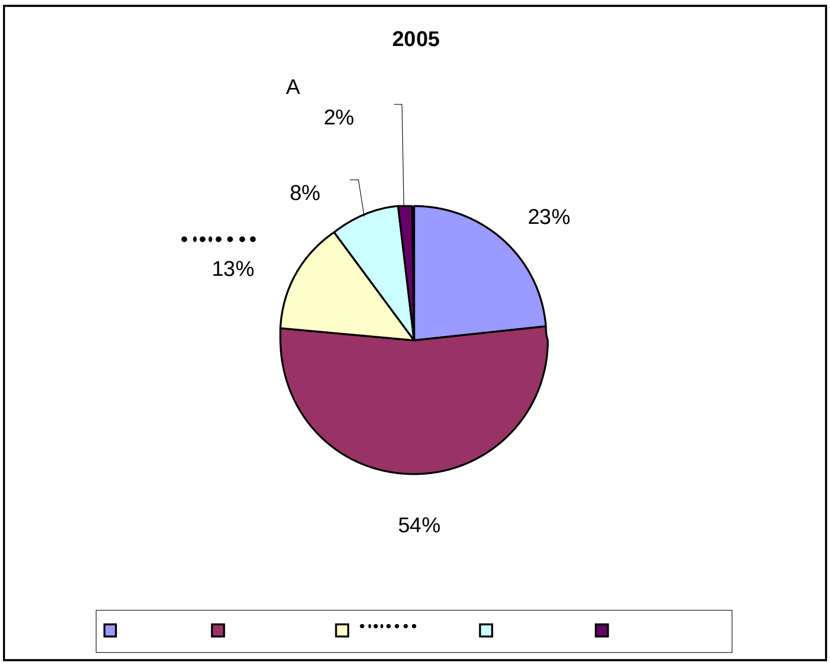


Figure 2.2.2: Market share of each activity sector in final energy consumption in 2005

Table 2.2.2: Final energy consumption per sector between 1990 and 2005 [ktoe]

Sector	1990	2000	2005
Industrial	268	437	430
Commercial	81	108	152
Household	111	215	244
Transportation	628	852	970
Agricultural	5	8	37
Total	1087	1633	1833

Source: Eurostat

2.2.1 Household Sector, Tertiary Sector and Agricultural Sector

Electricity is the energy product most consumed in the household sector, constituting 41% of final consumption in 2005. Petroleum products comprise 42%, whereas RES (solar energy, biomass) constitute 17%, mainly originating from solar thermal systems.

In the tertiary sector almost 80% of the energy consumed is electricity and 20% comes from petroleum products, while in the agricultural sector petroleum products dominate at 74%, with electricity at 24%.

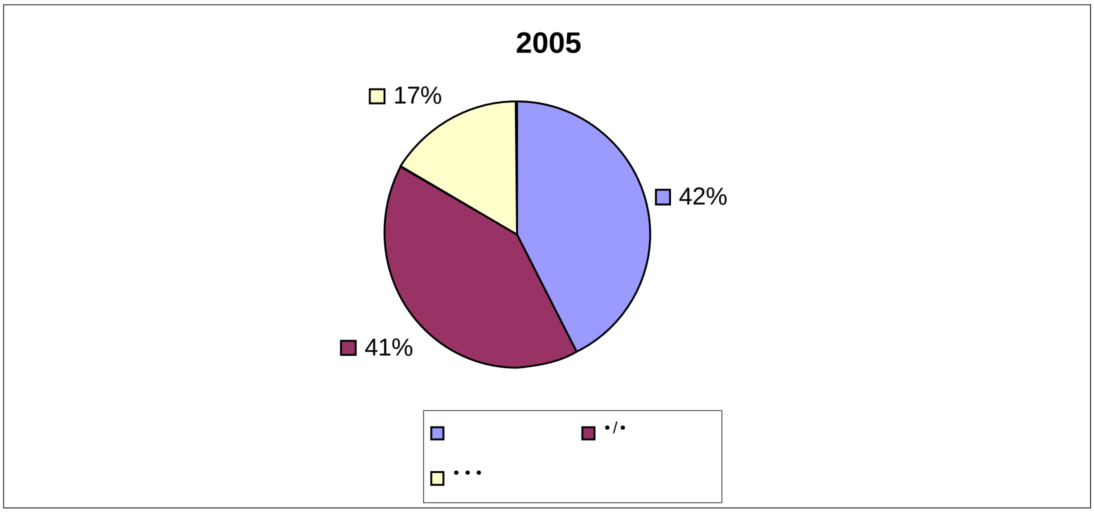


Figure 2.2.1.1: Fuel consumption in the household sector (2005)

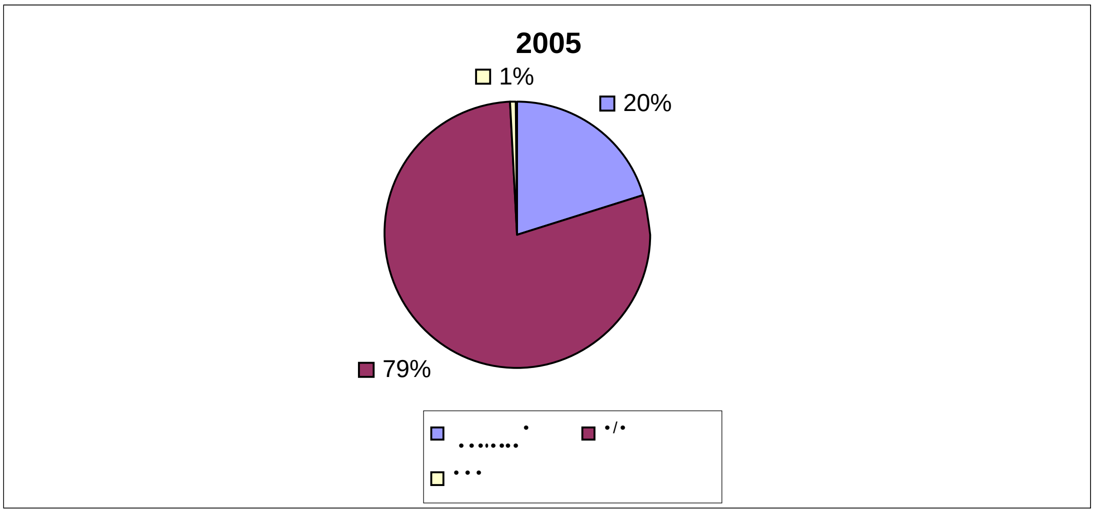


Figure 2.2.1.2: Fuel consumption in the tertiary sector (2005)

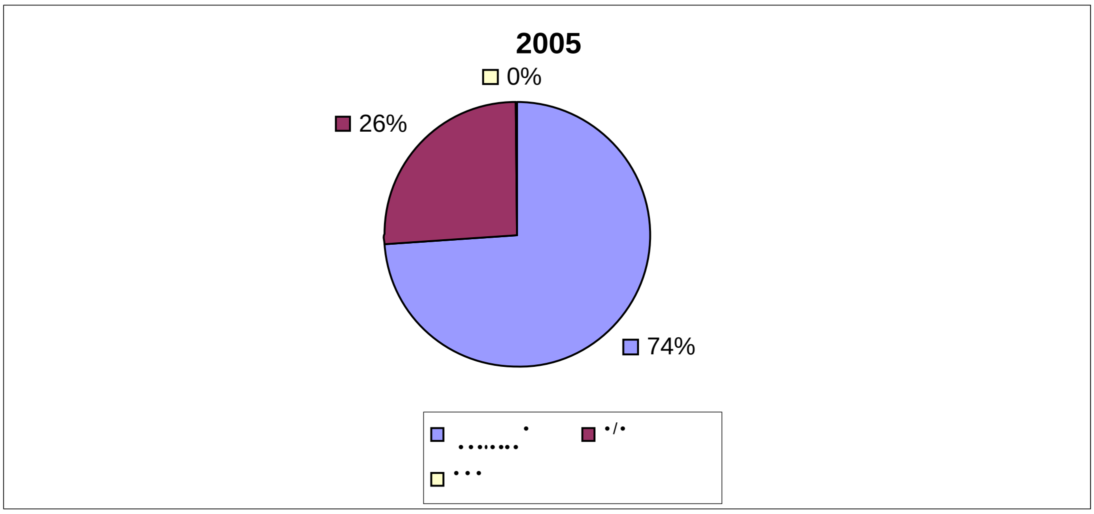


Figure 2.2.1.3: Fuel consumption in the agricultural sector (2005)

2.2.2 Manufacturing

The greatest contribution to industrial value added in Cyprus is from non-metallic minerals used in cement and brick factories. Final energy consumption in Cyprus's manufacturing industries comes, in descending order, from non-metallic minerals, the food industry, metal products, chemicals, plastics and textiles.

Table 2.2.2.1: Final energy consumption per industrial sector between 1990 and 2005 [ktoe]

Industrial Sector (ktoe)	1990	2000	2005
Total	267.6	437.2	430
Iron and Steel Industry	-	-	-
Non-Ferrous Metals Industry	-	-	-
Chemicals	2.4	2.4	2.4
Non-Metallic Mineral Products	124.2	219.8	193
Mining and Quarrying	0.0	0.0	2.4
Food Products, Beverages, Tobacco	4.8	11.9	14.3
Textiles, Leather, Clothing	2.4	2.4	0.0
Paper Manufacturing, Printing	0.0	2.4	2.4
Manufacturing of Machinery	2.4	2.4	2.4
Other Manufacturing	100.3	193.5	168.0
Other sectors	28.7	7.2	43.0

Source: Eurostat

2.2.3 Transport

Cyprus's transport sector mainly involves road and air transport, given that there is no domestic shipping or rail transport.

Table 2.2.3.1: Final energy consumption in Cyprus's transport sector in 2005 (ktoe)

Transport Sector	(NG + LPG)	Petrol	Kerosene	Diesel	Fuel Oil	Bio-fuels	Electricity	Total
Rail	-	-	-	-	-	-	-	-
Road	-	317.7		348.8	-	-	-	666.5
Air	-	-	298.6	-	-	-	-	298.6
Coastal	-	-	-	-	-	-	-	-
Total	-	317.7	298.6	348.8	-	-	-	970

2.2.4 Energy Intensity

Two macroscopic indicators are used internationally to depict energy consumption trends in an economy: primary energy intensity (ratio of total domestic consumption to GDP) and final energy intensity (ratio of final energy consumption to GDP).
Primary energy intensity describes the energy efficiency of the entire country, while final energy intensity describes energy efficiency with regard to final energy consumption.
The graphs show that from 1995 to 2004 primary energy intensity decreased at a rate of 1.8% per year, and that during the same period final energy intensity dropped by 1% each year. Primary and final energy intensities in 2004 were 0.21koe/EC00 and 0.16koe/EC00, respectively. The variations between primary and final energy intensities between 1995 and 2004 are depicted by means of the ratio of final energy intensity to primary energy intensity. This ratio increased from 63% in 1995 to 75% in 2004, signifying more rapid improvement in the efficiency of the transformation sector.

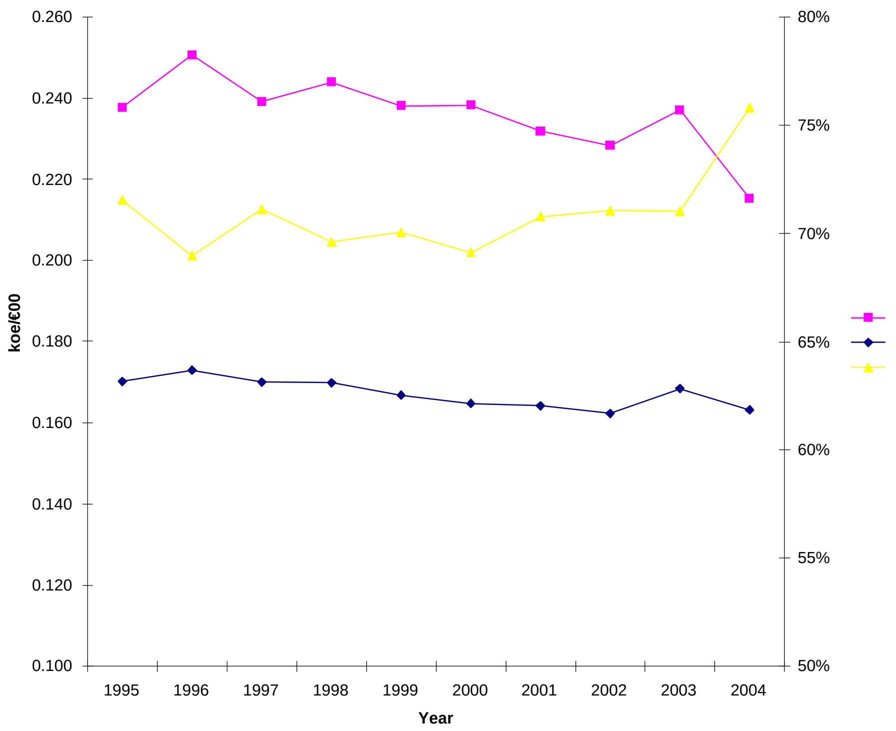


Figure 2.2.4: Energy Intensity

3 COGENERATION: THE SITUATION IN CYPRUS

CHP is, for the time being, not particularly developed in Cyprus. Until the end of 2006 there were 8 CHP plants, of which 3 belonged to Vassiliko Cement Works Ltd, 4 to Skouriotissa mines (Hellenic Copper Mines Ltd) and 1, a recent biogas plant, to N. Armenis and Sons Ltd, with an installed capacity of 250 kWe and 300 kWth. The favourable subsidisation climate resulted in 14 applications for financing being submitted in 2007 for biogas-fired CHP.

Conditions in Cyprus are evidently not very favourable for CHP development. For a CHP system to be financially viable, it must operate for a certain number of hours and must have a substantial heat or cooling load. Owing to weather conditions, Cyprus's heat load is very small in the tertiary and household sectors and, moreover, the local industry sector is small, since the country's economy is based on tourism and commerce.

There is, nevertheless, a considerable CHP potential in industry, hotels, hospitals and large office buildings. Furthermore, it is interesting to see to what extent CHP applications through the acquisition of heat from EAC power stations are technically and economically feasible.

Tables 3.1, 3.2 and 3.3 present CHP plants in operation in 2006.

Table 3.1: Fuel Consumption and Electricity & Heat Generation in Cyprus's existing CHP plants (2006)

Fuel Type		Unit	
Diesel	Fuel input	10^3 mt	1.60
	Fuel input	TJ(NCV)	66.30
	Gross electricity generated	GWh	7.90
	Net heat generated	TJ	12.50
	Of which sold to third parties	TJ	-
Liquefied Petroleum Gas	Fuel input	10^3 mt	2.60
	Fuel input	TJ(NCV)	110.00
	Gross electricity generated	GWh	13.00
	Net heat generated	TJ	26.20
	Of which sold to third parties	TJ	-
Total	Fuel input	TJ(NCV)	176.30
	Gross electricity generated	GWh	20.90
	Net heat generated	TJ	38.70

Table 3.2: Current situation of CHP per technology
Installed Capacity, Fuel Consumption, Electricity & Heat Generation (2006)

Type of Cycle	Maximum Capacity			Generation			Fuel	Number of Installed Units
	Electricity		Heat	Electricity		Heat	Input	
	CHP	Gross	Net	ECHP	Gross	Net		
	MW	MW	MW	GWh	GWh	TJ	TJ(NVC)	
Combined cycle (eff. < 80%)								
Gas turbine with heat recovery								
Internal combustion engine	2.30	8.50	3.00	8.70	20.90	38.70	176.30	7.00
Back pressure steam turbine								
Extraction condensing steam turbine (eff. < 80%)								
Other								
Subtotal	2.30	8.50	3.00	8.70	20.90	38.70	176.30	7.00
TOTAL (1+2)	2.30	8.50	3.00	8.70	20.90	38.70	176.30	7.00
-of which by autoproducers	2.30	8.50	3.00	8.70	20.90	38.70	176.30	7.00

Table 3.3: Current situation of CHP per sector
Installed Capacity, Fuel Consumption, Electricity & Heat Generation (2006)

	Maximum Capacity			Generation				
Sector	Electricity		Heat	Electricity		Heat	Fuel Input	Number of Installed Units
	CHP	Gross	Net	ECHP	Gross	Net		
	MW	MW	MW	GWh	GWh	TJ	TJ(NVC)	
Public Sector	0	0	0	0	0	0	0	0
Autoproducers	2.30	8.50	3.00	8.70	20.90	38.70	176.30	7.00
Solid Fuel Mining	0.80	4.00	1.00	6.00	13.00	26.20	110.00	4.00
Petroleum Mining & NG Extraction								
Coke Ovens								
Refineries								
Nuclear Fuel Mining and Processing								
Iron and Steel Industry								
Non-Ferrous Metals								
Non-Metallic Mineral Products	1.50	4.50	2.00	2.70	7.90	12.50	66.30	3.00
Mining and Quarrying								
Food Products, Beverages, Tobacco								
Textiles, Leather Manufacturing								
Paper Manufacture, Printing								
Transport Equipment Manufacturing								
Other Manufacturing								
Transport								
Tertiary Sector, etc.								
Other								
TOTAL	2.30	8.50	3.00	8.70	20.90	38.70	176.30	7.00

4 TECHNICAL POTENTIAL FOR CHP

4.1 Heat, Cooling and Electrical Loads required for CHP in Cyprus

The aim of this chapter is to determine suitable heat markets for CHP in Cyprus and to assess the technical potential for CHP. Heat markets have, therefore, been divided into different categories and criteria have been set for the selection of markets that are suitable for CHP. Data used in this report have mainly been obtained from completed questionnaires.
Potential CHP applications have been categorised using the method recommended by the European Union.

- CHP Technical Potential in the Industrial Sector
- CHP Technical Potential in the Tertiary Sector
- Biomass/Biogas Potential
- CHP Applications in the vicinity of central power stations

Tables 4.1 and 4.2 provide a breakdown of final energy consumption in Cyprus between 1990 and 2005.

Table 4.1: Heat – Breakdown of Final Consumption, 1990-2005 (GWh)

Sector	2001	2002	2003	2004	2005
Heat – Total Final Consumption (GWh)	19,522	19,873	20,665	20,047	21,425
Industry, including:	3,515	3,939	3,894	4,141	4,141
Iron and Steel	0	0	0	0	0
Non-Ferrous Metals	0	0	0	0	0
Chemicals	0	0	0	0	0
Non-Metallic Mineral Products	2,044	2,189	2,267	2,505	2,523
Mining and Quarrying	0	0	0	0	0
Food Products, Beverages, Tobacco	0	0	0	0	0
Textiles, Leather Manufacture	0	0	0	0	0
Paper Manufacturing, Printing	0	0	0	0	0
Transport Equipment Manufacturing	0	0	0	0	0
Other Manufacturing	1,471	1,750	1,627	1,636	1,618
Transport	10,721	10,372	11,020	9,927	11,213
Rail	0	0	0	0	0
Road	6,981	6,775	7,172	6,413	7,747
Air	3,740	3,597	3,847	3,486	3,466
Household Sector	3,082	3,243	3,301	3,486	3,511
Services	1,770	1,877	1,986	2,031	2,100
Agriculture, Forestry	434	442	464	462	460

Source: Cyprus Institute of Energy

Table 4.2: Electricity – Breakdown of Final Consumption, 1990-2005 (GWh)

Sector	2001	2002	2003	2004	2005
Electricity – Total Final Consumption (GWh)	3,110	3,385	3,645	3,749	3,960
Industry, including:	451	474	515	537	546
Iron and Steel	0	0	0	0	0
Non-Ferrous Metals	0	0	0	0	0
Chemicals	19	19	20	21	24
Non-Metallic Mineral Products	183	186	208	216	221
Mining and Quarrying	10	12	13	20	14
Food Products, Beverages, Tobacco	132	147	159	162	166
Textiles, Leather Manufacturing	14	13	13	11	11
Paper Manufacture, Printing	16	16	17	18	18
Transport Equipment Manufacturing	24	25	24	28	30
Other Manufacturing	53	56	61	61	61
Transport	24	26	30	31	31
Rail	24	26	30	31	31
Household Sector	1,042	1,157	1,294	1,316	1,433
Services	1,432	1,558	1,634	1,681	1,755
Agriculture, Forestry	93	101	113	114	118

4.2 Technical Potential for CHP in the Industrial and Tertiary Sectors

A preliminary feasibility study was conducted for the cogeneration plant of every undertaking on which a questionnaire had been completed. Calculations were performed on the data of the CHP plants meeting load demands (heat, cooling and electrical) recorded. The energy saved by each CHP plant compared with separate electricity generation and heating or cooling was then calculated. A synthesis of the results obtained from the various sectors of the sample was then performed based on EUROSTAT's NACE classification. Lastly, the overall figures of each NACE sector were obtained by extrapolating sample results to the total figure for each sector, based on total consumption indicated in Eurostat's balances and on data obtained from **selected clients of the Electricity Authority of Cyprus (EAC).**

The overall sample comprises **20** industrial firms, **11** hotel units, **3** hospitals and **23** buildings. The industrial firms participating in the sample were from the "agriculture – stock farming", "food products – beverages", "non-metallic minerals" and "non-ferrous metals" sectors of activity.
The distribution of undertakings into the four sectors above is shown in Table 4.2.1.

Table 4.2.1: Distribution of industrial firms per sector

SECTOR	Number of questionnaires in sample
Agriculture – Stock farming	4
Food Products - Beverages	10
Non-metallic mineral products	5
Non-ferrous metals	1
TOTAL INDUSTRY	20

Table 4.2.2 shows building categories included in the survey.

Table 4.2.2: Building categories included in the sample

Other non-residential buildings	Number of questionnaires in sample
Retail buildings	12
Telecommunications buildings	1
Banks	5
Public administration buildings	3
Universities	1
Television buildings	1
TOTAL	23

The tables below show the total consumption of electricity and heat (GWh/year), the technical potential for CHP (MWe and MWth) and primary energy saved (GWh).

Table 4.2.3: Technical Potential for Cogeneration per industrial sector (using data from the questionnaires)

SECTOR	Thermal Energy (GWh/year)	Electrical Energy (GWh/year)	CHP Technical Potential (MWe)	CHP Technical Potential (MWth)	PES (GWh) Total per sector
Agriculture – Stock farming	347	118	70.7	120.4	177.17
Food Products - Beverages	350	166	49.4	101.9	122.79
Non-metallic mineral products	1828	221	100.9	221.9	597.39
Non-ferrous metal ores	244	73	22.0	33.0	132.07
TOTAL INDUSTRY	2769	578	243	477.2	1029.42

Table 4.2.4: Technical Potential for Cogeneration in Hotels (using data from the questionnaires)

SECTOR	Thermal Energy (GWh/year)	Electrical Energy (GWh/year)	CHP Technical Potential (MWe)	CHP Technical Potential (MWth)	PES (GWh) Total per sector
Hotels	223	263	33.2	50.7	183.2

Table 4.2.5: Technical Potential for Cogeneration in Hospitals (using data from the questionnaires)

SECTOR	Thermal Energy (GWh/year)	Electrical Energy (GWh/year)	CHP Technical Potential (MWe)	CHP Technical Potential (MWth)	PES (GWh) Total per sector
Hospitals	50	66	5.6	10.2	30.8

Table 4.2.6: Technical Potential for Cogeneration in Other Non-Residential Buildings (using data from the questionnaires)

SECTOR	Thermal Energy (GWh/year)	Electrical Energy (GWh/year)	CHP Technical Potential (MWe)	CHP Technical Potential (MWth)	PES (GWh) Total per sector
Other Non-Residential Buildings	88	188	26.1	42.5	13.2

4.3 Technical Potential for CHP from Power Stations

4.3.1 Overview

The Electricity Authority of Cyprus (**EAC**) currently owns the power stations listed below in descending order of age:

i) Moni Power Station, consisting of six (6) 30 MWe steam power plants burning heavy fuel oil and three (3) 37.5 MWe open-cycle gas turbines burning light fuel oil;
ii) Dekeleia Power Station, consisting of six (6) 60 MWe steam power plants burning heavy fuel oil;
iii) Vassilikos Power Station, consisting of three (3) 130 MWe steam power plants burning heavy fuel oil and one (1) 38 MWe open-cycle gas turbine burning light fuel oil.

It should be noted that Moni and Dekeleia power stations are situated in the vicinity of the cities of Limassol and Larnaca, respectively, and particularly close to cities in tourist resort areas (less than 8 km from them). On the contrary, Vassilikos Power Station is located at a distance of 30 km from the city of Limassol. All stations are coastal.

It is possible to obtain usable thermal energy from the EAC's power stations, thereby, enabling them to cogenerate heat and power to some extent by:

a) Recovering residual heat from the exhaust gases at the cold end of the boiler (after the LUVO combustion air preheater);
b) Using extraction steam from existing extraction points in the plants' steam turbine, which is accompanied by a reduction in the electricity generated;
c) Using superheated steam from the boiler's outlet (upstream of the steam turbine), which requires that the boiler's thermodynamic properties be adjusted (this method will not be analysed because it results in significant reduction in electricity generated).

Given that all the steam power plants mentioned above have 100% water recirculation in the vaporisation system and that there should be continuous blowdown (removal of water so as to maintain desired quality) from the equipment's drum, the resulting residual heat can serve as a fourth **(d)** alternative by means of which the plants can generate a useful heat load. More specifically, water is removed from the blowdown apparatus at very high pressures (slightly lower than the pressure of superheated steam) and at temperatures slightly below saturation point, while supply can be up to 3% of superheated steam supplied by the plant. For example, in the case of Vassilikos power station, a useful heat load of approximately <u>2.3 MWth</u> can be generated in this manner by each plant (given a 2% blowdown and thermal exploitation at temperatures up to 90^{o}C). This method will not be further assessed in this study.

Thermal energy may be used:

· to meet the heating needs of a neighbouring city/community (district heating),
· to meet the heating needs of a neighbouring city/community using absorption chillers (district cooling),
· to produce desalinated water from seawater using a thermal method,
· in the thermal processes employed by industries, etc.

4.3.2 Heat Load Generation using Exhaust Gases

In case **(a)** above, a "worthwhile" heat load can be obtained if the temperature of the exhaust gases after the LUVO preheater (before the flue) are "significantly" higher that the acid dew point of exhaust gases. This may occur owing to:

- the age of the plants, which may result in reduced thermal efficiency of the boiler's heat-exchange surfaces,
- the plants' fuel being converted from high-sulphur fuel oil to low-sulphur fuel oil, which results in a lower acid dew point than the initial value applicable when the plants were designed.

In this case, exhaust gas heat exchangers must be installed at the cold end of the boiler (after the LUVO preheater) and superheated service water must be directly produced so as to cool exhaust gases at temperatures that are slightly higher than the acid dew point. Based on the data obtained (exhaust gas temperature after LUVO below 150^{o}C in all plants) and given that the acid dew point of exhaust gases from the low-sulphur fuel currently being burned by the plants is estimated to be 130-135^{o}C, the heat load is not worth recovering. For example, in the steam power plants of Moni power station, the heat load

recovered so as to reduce exhaust gas temperature to 135°C is approximately **1 MWth** per plant. Furthermore, this heat load is reduced in proportion to the drop in each plant's workload.
Consequently, <u>this case will not be further examined</u>.

The procedure described above is of particular interest in the case of open-cycle light-fuel-oil steam turbine units that discharge exhaust gases into the atmosphere at very high temperatures (possibly above 400°C). In this case, a heat recovery boiler could be installed in order to generate a large heat load in the form of superheated steam or water. Given that these plants usually only operate during the summer months in order to meet peak electric load demands, the heat load recovered would only be of interest for district cooling or the production of desalinated water. Alternatively, the possibility of operating these plants for cogeneration purposes for a longer period of time could be assessed using technical and economic criteria. Given the absence of such data, <u>this case will not be further examine, either</u>.

4.3.3 Heat Load Generation using Extraction Steam

In case **(b)** above, all steam turbines have steam of the required thermodynamic properties and the maximum heat load that can be extracted for thermal purposes is limited by:

- the maximum loss of electrical power accepted by the power company given any reduction in electrical power and energy efficiency in the system (note that if thermal energy demand during the winter months is the same as in district heating, then there is no question of electrical power efficiency),
- steam turbine strength issues to be investigated.

Extraction steam is obtained from existing extraction points in the steam turbine so as to achieve regenerative preheating of the condensate/feed water in water/steam heat exchangers, without having to consequently convert the steam turbine in any way. In contrast with heat recovery from exhaust gases, the heat load derived from extraction steam can be maintained at nominal (maximum) levels for substantial workloads in the plant (usually from more than 75% to the plant's full workload). Note, however, that there is a slight increase in electric power loss during cogeneration in line with the plant's smaller load, as a result of a reduction in the thermodynamic properties of the extraction steam and the consequent demand for more extracted steam to be supplied.
Once it has yielded the expected heat load, the extraction steam is usually fully recovered and returned to the plant's water/steam cycle. Note that if the heat load is used for desalination, the condensate might not be recovered, depending on the technology chosen.

Extraction steam at a pressure higher than 3 bar may be used in all "heat load" cases mentioned in paragraph (1) above (district heating, district cooling, production of desalinated water), except in industries with unknown requirements and depend on the particular features of the industrial processes concerned. Note that the higher the thermodynamic properties of steam at extraction point, the greater the expected drop in the electric power generated during cogeneration.

Should the heat load be used to meet district heating demands, as is usually the case, the extraction steam is used in a heat exchange apparatus to produce superheated water at a temperature of 120°C and more rarely of 90°C.

The possibility should also be investigated of meeting heat load demands by means of a pair of heat exchangers connected in series, using extraction steam from two different points in the wind turbine, namely from a point where the steam properties are as described above for the 2nd of the exchangers connected in series and from a point with lower thermodynamic steam properties for the 1st of the exchangers connected in series. This increases the availability of the heat load generation system, even if achieved at smaller loads, making it possible for the system to operate when one branch (exchanger) has broken down, and, in addition, less electricity is lost through the operation of such as system.

In any event, the steam turbine manufacturer's consent and confirmation that the turbine will operate safely and reliably under the new conditions is required before increasing extraction steam supply from any point in the steam turbine. More specifically, any impact on the endurance of the steam turbine's stages at the points where extraction is to take place must be assessed, given the change in the different pressures exerted upstream and downstream of the blade row as a result of the change (increase) in the supply of extraction steam. The impact is expected to be greater the higher the pressure at which there is a change in extraction steam supply.

4.3.4 Power Plant Cogeneration Heat Load

Based on the above, the following assessments have been made. Potential load has been estimated by taking into consideration that 300 MWe steam turbines in Greece have managed, given their manufacturer's consent, to generate a cogeneration heat load of up to 70 MWth. Note that in most cases heat load generation was put into effect only after the plant had been in operation for many years and without any provision having been made for it in the steam turbine's initial design.
Relevant calculations are presented in the annex at the end of the chapter.

VASSILIKOS Steam Power Station
The plants are similar in terms of their water/steam cycle.
Each plant can provide a heat load from steam extracted from steam turbine N•. 4 (medium-pressure turbine outlet, with a pressure of 3.069 bar when the plant is at full load) and steam turbine No. 3 (1st extraction of low-pressure turbine, with a pressure of 2.207 bar when the plant is at full load).
Assuming that the system operates by combining steam extractions from both the above extraction points, each plant is estimated to have a heat load supply capacity of **30 MWth** with a parallel loss of about **6.7 MWe** of electric power when the plant is at full load. Moreover, provision has initially been made for 40% (12 MWth) of the above heat load to be allocated to the 2nd exchanger, which functions at a higher steam pressure, and 60% (18 MWth) to the 1st exchanger, and for the condensate to be subcooled by 10 K so as to increase thermal exploitation.
Given the above, the total heat load that can be generated by Vassilikos power station is estimated to be **90 MWth** (= 3 x 30 MWth), with a total reduction of 20.4 MWe (= 3 x 6.8 MWe) in electricity generated when plants are at full load.
The cost of supplying and constructing a 30 MWth hot-water system using district heating technology is estimated at approximately **2.4–2.7 million euro**. The estimate does not include the district heating system's hot-water distribution network (pipes, pumps, etc.) from the boundary of the station to consumption points.

DEKELEIA Steam Power Station
All pairs of power plants, namely 1 & 2, 3 & 4, and 5 & 6, are similar as regards their water/steam cycle.

Plants 1 & 2
Each of Plants **1 & 2** are believed to capable of providing a heat load from steam extracted from steam turbine N•. 3 (towards the degasifier, with a pressure of 4.61 bar when the plant is at full load) and steam turbine no. 2 (towards the last LPH, with a pressure of 2.37 bar when the plant is at full load). Assuming that the system operates by combining steam extraction from both extraction points above, each plant is estimated to have a heat load supply capacity of **14 MWth** with a parallel loss of about **3.4 MWe** of electric power when the plant is at full load. Moreover, provision has initially been made for 40% (5.6 MWth) of the heat load above to be allocated to the 2nd exchanger, which functions at a higher steam pressure, and 60% (8.4 MWth) to the 1st exchanger, and for the condensate to be subcooled by 10 K so as to increase thermal exploitation.

Plants 3 & 4
Each of Plants **3 & 4** are believed to be capable of providing a heat load from steam extracted from steam turbine N•. 3 (towards the degasifier, with a pressure of 3.86 bar when the plant is at full load) and steam turbine No. 2 (towards the last LPH, with a pressure of 1.74 bar when the plant is at full load). Assuming that the system operates by combining steam extraction from both extraction points above, each plant is estimated to have a heat load supply capacity of **14 MWth** with a parallel loss of about **3.25 MWe** of electric power when the plant is at full load. Moreover, provision has initially been made for 40% (5.6 MWth) of the heat load above to be allocated to the 2nd exchanger, which functions at a higher steam pressure, and 60% (8.4 MWth) to the 1st exchanger, and for the condensate to be subcooled by 10 K so as to increase thermal exploitation.

Plants 5 & 6
Each of Plants **5 & 6** are believed to be capable of providing a heat load from steam extracted from steam turbine N•. 3 (towards the degasifier, with a pressure of 3.56 bar when the plant is at full load) and steam turbine No. 2 (towards the last LPH, with a pressure of 1.86 bar when the plant is at full load). Assuming that the system operates by combining steam extraction from both extraction points above, each plant is estimated to have a heat load supply capacity of **14 MWth** with a parallel loss of about **3.0 MWe** of electric power when the plant is at full load. Moreover, provision has initially been made for 40% (5.6 MWth) of the heat load above to be allocated to the 2nd exchanger, which functions at a lower steam pressure, and 60%

(8.4 MWth) to the 1st exchanger, and for the condensate to be subcooled by 10 K so as to increase thermal exploitation.

Given the above, the total heat load that can be generated by Dekeleia power station is estimated at **84 MWth** (= 6 x 14 MWth), with a total reduction of 19.3 MWe (=2 x 3.4 MWe + 2 x 3.25 MWe + 2 x 3.0 MWe) in electricity generated when plants are at full load.
The cost of supplying and constructing a **14 MWth** hot-water system using district heating technology is estimated at approximately **1.6–1.9 million euro**. This estimate does not include the district heating system's hot-water distribution network (pipes, pumps, etc.) from the boundary of the station to consumption points.

<u>MONI Steam Power Station</u>

Data are only available for plants 4, 5 and 6 of Moni Power Station.
From the data obtained, it appears that each plant capable of providing a heat load from steam extracted from steam turbines N•. 3 and No. 2. The maximum heat load that can be generated by each plant is not expected to exceed 6 MWth, and there are no data available to assess the drop in electric power generated (although it is not expected to exceed 1.7 MWe when the plant is at full load).
Assuming that plants 1, 2 and 3 have a similar water/steam cycle, the total heat load that could be obtained from Moni Power Station is **36 MWth** (= 6 x 6 MWth).

4.3.5 Conclusions

The largest heat load seems to be available from Vassilikos power plants, due to their size. Given that the station is relatively far from the nearest city (approximately 30 km from Limassol), heat load transportation is likely to consume a lot of energy (if, for example, we were to assume hot water speed in the pipes to be 1.5 m/s, about 800-900 kWe of electricity would be consumed to operate the pumps) and the heat insulation of the pipes will have to be substantially improved in order for the temperature drop to be maintained within acceptable limits. The latter would not be an issue if cold desalinated water was to be transported.

The heat load that can be generated by Moni and Dekeleia power plants can be absorbed in its entirety in order to meet the needs of residential complexes and hotel units in Limassol and Larnaca, respectively. Particularly where Limassol is concerned, the heat load of Moni power plants is clearly not sufficient to meet the needs of the entire city.

Heat Load and Electricity Loss Calculation Tables

Vassilikos Power Station, Plants 1, 2, 3 – Heat Load Generation and Consequences

Extraction No	-	4	3	Total
Extracted steam pressure, pD	bar	3,07	2,21	
Extracted steam enthalpy, hD	kJ/kg	2.869,90	2.818,60	
Extracted steam saturation temp, ts	oC	134,30	123,30	
Condensate enhtalpy (subcooling 10K), hcond	kJ/kg	520,79	474,00	
Extacted steam enthalpy drop, DhD	kJ/kg	2.349,11	2.344,60	
Extracted steam flow, mD	t/h	18,39	27,64	
Thermal power, Qth	MWth	12,00	18,00	30,00
Calculation of elecric power loss				
Steam turbine exhaust enthalpy, hDexit	kJ/kg	2.298,50	2.298,50	
Steam turbine-generator efficiency (elec x mech)	%	97,00	97,00	
Loss of electric power (approx), Dpel	MWel	2,83	3,87	6,70

Dekeleia Power Station, Plants 1, 2 – Heat Load Generation and Consequences

Extraction No	-	3	2	Total
Extracted steam pressure, pD	bar	4,61	2,38	
Extracted steam enthalpy, hD	kJ/kg	2.787,70	2.879,00	
Extracted steam saturation temp, ts	oC	148,80	125,75	
Condensate enhtalpy (subcooling 10K), hcond	kJ/kg	584,03	485,50	
Extacted steam enthalpy drop, DhD	kJ/kg	2.203,67	2.393,50	
Extracted steam flow, mD	t/h	9,15	12,63	
Thermal power, Qth	MWth	5,60	8,40	14,00
Calculation of elecric power loss				
Steam turbine exhaust enthalpy, hDexit	kJ/kg	2.274,60	2.274,60	
Steam turbine-generator efficiency (elec x mech)	%	97,00	97,00	
Loss of electric power (approx), Dpel	MWel	1,26	2,06	3,32

Dekeleia Power Station, Plants 3, 4 – Heat Load Generation and Consequences

Extraction No	-	3	2	Total
Extracted steam pressure, pD	bar	3,86	1,74	
Extracted steam enthalpy, hD	kJ/kg	2.958,00	2.619,90	
Extracted steam saturation temp, ts	oC	142,34	115,89	
Condensate enhtalpy (subcooling 10K), hcond	kJ/kg	555,77	440,21	
Extacted steam enthalpy drop, DhD	kJ/kg	2.402,23	2.179,69	
Extracted steam flow, mD	t/h	8,39	13,87	
Thermal power, Qth	MWth	5,60	8,40	14,00
Calculation of elecric power loss				
Steam turbine exhaust enthalpy, hDexit	kJ/kg	2.205,50	2.205,50	
Steam turbine-generator efficiency (elec x mech)	%	97,00	97,00	
Loss of electric power (approx), Dpel	MWel	1,70	1,55	3,25

Dekeleia Power Station, Plants 5,6 – Heat Load Generation and Consequences

Extraction No	-	3	2	Total
Extracted steam pressure, pD	bar	3,56	1,74	
Extracted steam enthalpy, hD	kJ/kg	2.967,30	2.611,94	
Extracted steam saturation temp, ts	oC	139,50	118,00	
Condensate enhtalpy (subcooling 10K), hcond	kJ/kg	544,23	452,89	
Extacted steam enthalpy drop, DhD	kJ/kg	2.423,07	2.159,05	
Extracted steam flow, mD	t/h	8,32	14,01	
Thermal power, Qth	MWth	5,60	8,40	14,00
Calculation of elecric power loss				
Steam turbine exhaust enthalpy, hDexit	kJ/kg	2.246,60	2.246,60	
Steam turbine-generator efficiency (elec x mech)	%	97,00	97,00	
Loss of electric power (approx), Dpel	MWel	1,62	1,38	2,99

4.4 Technical Potential for CHP from Biomass

Available biomass can be used in cogeneration plants as follows:

- Solid biomass can be burned and the heat generated used for processes on site, thus meeting the thermal needs of manufacturing industries, buildings or small heating networks;
- Electricity and heat can be cogenerated at organic waste processing plants and the biogas produced can be used in livestock farms and industrial units;
- Electricity and heat can be cogenerated and the biogas produced can be used at urban waste and refuse processing plants.

In order to examine the possibility of developing such investments, the following must also be assessed:

- Biogas quantities available
- Heat loads that can be attained through the operation of CHP plants (thermal energy demand)
- Cost-efficiency of such investments.

Heat load demands that can be met by biomass CHP plants include:

- Heat for processes at small and large industrial plants producing biomass products. Wood industry in operation on the island belongs to this category;
- Heat for processes at small and large industrial plants that has up to now been generated using imported petroleum. Ceramics factories in operation belong to this category;
- Interior heating at large facilities with small heating networks. Industrial zones and industrial parks belong to this category;
- Heating for livestock farming units.

4.4.1 CHP plants burning solid biomass

CHP applications examined here, that use biomass products as a fuel, are based on the utilisation of industrial by-products obtained through forest product processing and on applications that make use of agricultural residues. The calculations made aim to evaluate biomass potential for CHP applications, and to determine installable power while taking into account key technical and economic limitations. Special calculation tools and databases developed by the CRES for assessing biomass potential have been used for these calculations.

This method has been implemented as follows:
<u>Stage One</u>: Determination of prospective sites for the installation of potential power stations, while taking into consideration heat load demand and biomass availability.
Research on the loads at different sites was conducted with the use of questionnaires. Table 4.4.1.1 below shows the estimated annual energy demand of industries that completed the questionnaires. The calculations performed were based on the quantities (biomass supply, biomass burned, fossil fuels used) and parameters (heating value, moisture content) obtained from the research conducted.

Table 4.4.1.1: Estimated annual energy demand at plants

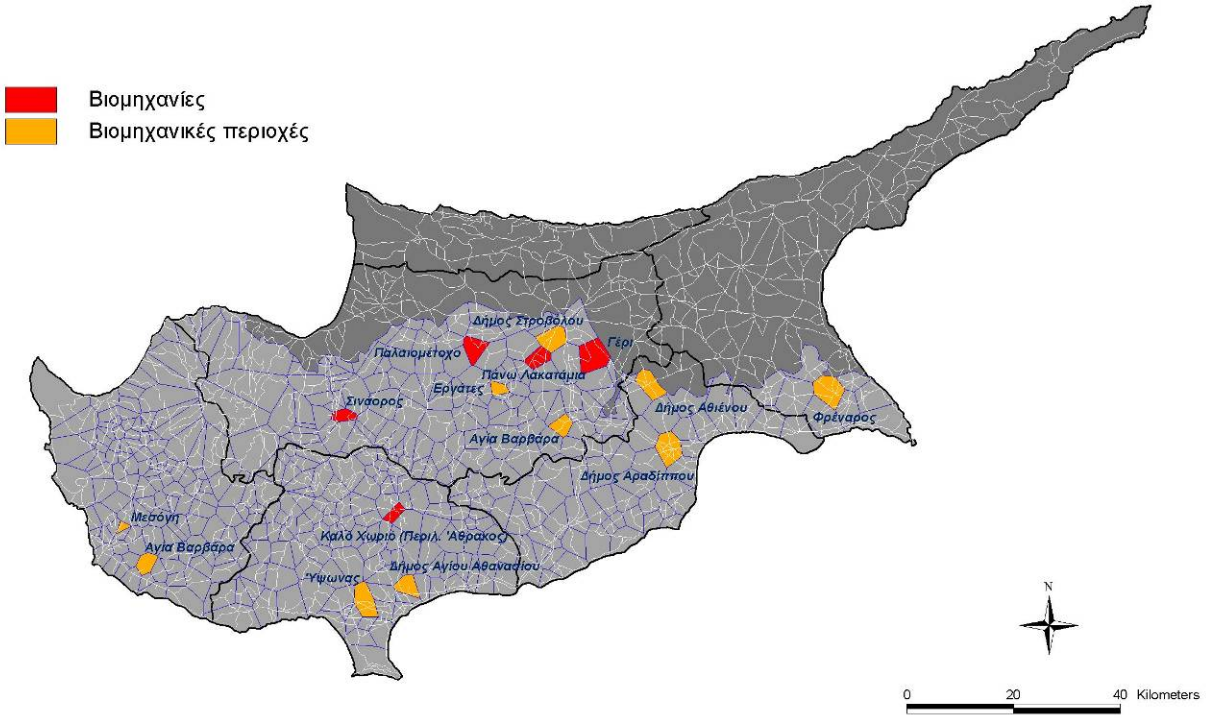
TYPE*	AREA	MUNICIPALITY	LOAD_MWh
Ceramics	Lakatamia	Lakatamia	31,350
Ceramics	Geri Industrial Zone	Geri	45,120
Ceramics	Kalo Horio	Kalo Horio	36,000
Wood**	Palaiometoho	Palaiometoho	15,387
Food Products	Agios Athanasios Ind. Zone	Agios Athanasios	12,000
Food Products	Larnaca Industrial Zone	Aradippou	11,150
Food Products	Lakatamia	Lakatamia	3,700
Food Products	Agios Athanasios Ind. Zone	Agios Athanasios	5,200
Food Products	Lakatamia	Lakatamia	11,035
Food Products	Hypson Industrial Zone	Hypson	4,625
Metals	Sinaoros	Sinaoros	18,000

* *The cement industry was not taken into account.*

The total load was calculated as follows:

Total heat load = Heat generated from own consumption of biomass products** + Heat generated from conventional fuels.

*** Only applicable for the wood industry which burns about 600 tons of residue*



Map 4.4.1.1: Prospective sites for CHP plants and industrial heat demand

Map 4.4.1.1 above shows potential sites for CHP plants, having taken into account the data in Table 4.4.1.1 and existing industrial zones that have plants demanding thermal energy.

<u>Stage Two</u>: Calculation of available biomass produced from industrial processes
This stage involved calculating the quantities of residue (wood, food processing residues, etc.) available at plants with a demand for heat loads to be used in heating processes. **The aim of the task was to determine the availability of fuels on the same sites as the loads.** This task was carried out by means of questionnaires completed on site.

Given that, based on questionnaires completed, there is only one such site (the wood industry plant in Palaiometoho district), the other plants will use biomass to be transported from production sites, in this way adding transportation costs to the overall operating cost.

<u>Stage Three</u>
The feasibility of building the CHP plants was determined during this stage with the use of CRES computational models for assessing biomass potential.
Technically and economically exploitable biomass potential can be defined as *the maximum quantity of biomass that can be utilised to generate energy in each area, so that its sale results in a profit*.
The model, which is used in the software developed by the CRES, is based on an optimisation method and takes into account the conclusions and calculations of the two previous stages as well as the estimated available potential.
The aim of the objective function determining the collection, preprocessing, transport, storage, energy conversion and energy distribution processes is to minimise the cost of all these processes.

The factors included are:
G: Gains from the sale of energy
CP: Cost of setting up and operating the plant
CT: Cost of transporting biomass
CC: Cost of collecting and preprocessing or cost of purchasing biomass
CD: Cost of thermal energy distribution network

The overall cost equation can be written as follows:

$$C = -G+CP+CT+CC+CD$$

When fully expanded, the equation above comprises, along with its associated constraints, both continuous and discrete variables. A mixed integer programming solver is, therefore, needed and the GAMS model solver has been chosen for this purpose.

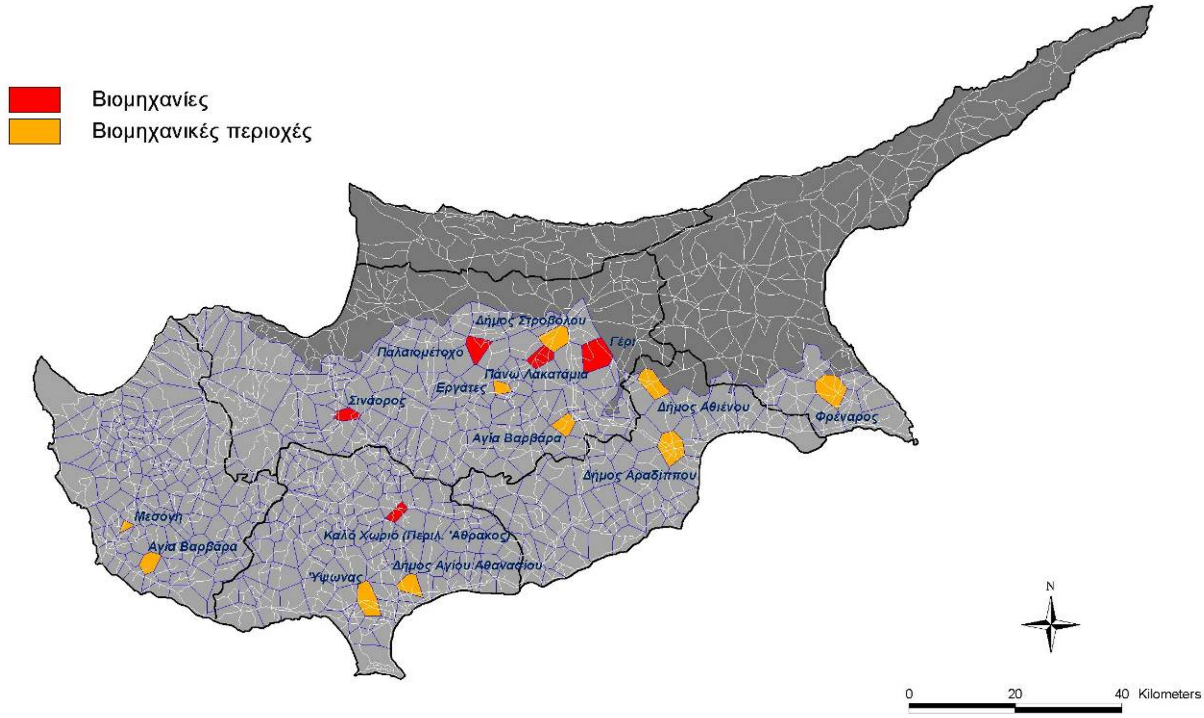
By solving the model we can determine the power that can be installed in each region while taking into account biomass availability (at the plant or in neighbouring areas), the plant's own heat load demands •• be met as well as key economic parameters pertaining to each power station.
Table 4.4.1.2 below shows the model's results for the entire country, given the following basic economic figures:
Selling price of electricity: 94 €/MWh
Selling price of thermal energy: 30 €/MWh (indicative price in Greece, given that Cyprus does not have such a market)
Biomass acquisition and preprocessing cost: 0.3 k€/GJ
Biomass transport cost: 0.066 k€/(TJ/km)
Deflators for all economic figures: 3%; survey period: 20 years.

Table 4.4.1.2 Model results for basic cogeneration scenario

Community – Site	Power (• We)	Power (• Wth)	Biomass (TJ)
Kalo Horio	3.74	8.22	235.68
Agios Athanasios Municipality	1.79	3.93	112.62
Sinaoros	1.84	4.05	117.02
Lakatamia Municipality	2.15	4.73	180.98
Palaiometoho	1.79	3.93	112.62

It is clear from the model described and the parameters used that the resulting thermal and electric power determines the maximum power that can be installed, as long as *the expenditure calculated in each case does not exceed the revenue expected*. To this effect, and given that factors such as financial support measures, borrowing costs and profitability indicators (return on investment) have not been incorporated in the calculations, these estimates determine the *technical potential of agricultural and industrial biomass that can be used in CHP plants*.

In each case and having taken into account the total available potential, whether this is derived from industrial products or agricultural activities, the quantity of usable biomass has been maximised.
Based on the results of the basic scenario presented in Table 4.4.1.2, the total electric power that can be installed given the above assumptions is 11.3 MWe and the corresponding thermal power 24.8 MWth. Map 4.4.1.2 outlines potential CHP plant sites.



Map 4.4.1.2: Prospective cogeneration sites using biomass as a fuel – Model results

The following observations can be made based on the results of the basic scenario presented in the previous table and map:

- The prospective sites/potential plants are in the island's central regions, where most industrial activities are located, whereas the largest quantity of available biomass is found in western regions (see maps 4.4.1.1 and 4.4.1.2). This leads to higher transport costs in large areas with available biomass, which is, consequently, not recommended for cogeneration by the model. Characteristically, of the total 1880 TJ or so of biomass available from estimated agricultural residues (Table 4.4.1.2), only 758 TJ (corresponding to 40,000 tons annually) is recommended for use at CHP plants in a financially viable manner. Encouragement should be provided for the remaining quantities to be used as fuel for thermal purposes.
- The cost of acquiring biomass (removal from field, preprocessing) was set at 0.3 k€/GJ. According to the sensitivity analysis conducted for this parameter, potential plants cease to be cost-efficient at prices exceeding 1 k€/GJ. This cost will, consequently, have to be subsidised if it proves to be higher in practice.
- Transportation cost is the most important factor where the cost-efficiency of the plants described is concerned, since, according to the sensitivity analysis conducted, if the cost should exceed 0.066 k€/(TJ/km) it would make the application in question impossible. The price quoted above corresponds to 0.6 €/t/km[1].

4.4.2 Centralised co-digestion plants

The Danish model of centralised biogas plants seems to have good prospects for Cyprus. In Denmark, approximately 1,325,000 tons of organic waste is managed annually at 20 centralised plants with an annual production of 50,000,000 m^3 of biogas, which contributes approximately 1 PJ of total energy to Denmark's energy system.

Centralised co-digestion plants rely on biogas production through the process of anaerobic digestion (AD), using a wide range of organic waste comprising livestock manure (80%) and agro-industrial waste, urban organic refuse and biologically treated sewage. Centralised plants are set up in areas with a high waste potential so as to reduce waste transportation costs. Care should be taken so that the end product is of

[1] Institut für Technikfolgenabschätzung und Systemanalyse Forschungszentrum Karlsruhe (ITAS)

high quality and safe when recycled as fertiliser. **For this reason, information must be gathered on each type of waste before it is transferred to the tanks**. Such information includes:

- waste origin (details of the company that produced it, raw materials and processing methods, quantities available, etc.),
- waste macro- and micro-nutrient content, heavy metal content, pH, dry matter content, etc.,
- waste organoleptic properties, such as colour, texture, odour, etc. and
- potential pathogens when waste is processed or finally used as fertiliser.

Livestock manure is collected from different livestock farms and stored in pre-collection tanks at selected points. It is then transported in suitable tanker trucks to the centralised plant, where it is mixed with other organic waste, homogenised and pumped to the digesters so that the AD process may begin. AD takes place at a temperature of 30-40ºC (mesophilic) or 50-55ºC (thermophilic), under controlled hygienic conditions, so as to reduce pathogenic odours and environmental pollution.
The products of anaerobic digestion are:

- biogas, which is channelled to a suitable gas holder and, after being cleaned and dehumidified, is used to feed internal combustion engines or gas turbines for heat and power generation, and
- digested residue, which can be converted to solid and liquid fertilisers after undergoing appropriate separation and evaporation.

A centralised co-digestion plant is an integrated livestock manure and organic waste management system generating renewable energy (biogas) and providing substantial environmental and economic benefits, such as:

- Energy production from RES
- Less organic waste
- Fewer greenhouse gas emissions
- Fewer pathogens
- Higher fertiliser performance
- Fewer odours and less visual pollution
- Money saved by farmers

Following this line of thought and given that Cyprus annually produces approximately 750,000 tons of livestock manure and 65,000 tons of industrial waste according to existing surveys[2], four plants could be established on sites that have a high organic waste potential and severe environmental problems from uncontrolled waste disposal.
More specifically:

1 centralised co-digestion plant in Aradippou area, **550 tons/day)**
2 centralised co-digestion plants in Orounta area, from **550 tons/day**
1 centralised co-digestion plant in Athienou area, **300 tons/day**

Table 4.2.2.1 Estimated potential in the three concentration areas

	Athienou	Aradippou	Orounta
CH_4 Production	1,984,000 m^3/year	3,648,000 m^3/year	(2) 3,648,000 m^3/year
CH_4 Energy Content (9.94kWh/m^3)	19,720,960 kWh/year	36,261,120 kWh/year	(2) 36,261,120 kWh/year
Plant Capacity	2,251 kW	4,139 kW	(2) 4,139 kW
Electricity Generation*	7,213 • Wh	13,263 • Wh	(2) 13,263 • Wh
Heat Generation**	8,677 • Wh	15,955 • Wh	(2) 15,955 • Wh

**38.5% output, 5% maintenance **44% output*

In order to determine the technical and economic figures for centralised biogas plants in Cyprus, four scenarios have been examined based on Danish models: 100 tons/day, 300 tons/day, 550 tons/day and 800 tons/day (Table 4.2.2.2).

Biomass potential for Gas Production in Cyprus-22/05/2006[2]

Table 4.2.2.2

	100 tons/day	300 tons/day	550 tons/day	800 tons/day
Biogas Produced	1.6 mil Nm^3/year	3.1 mil.Nm^3/year	5.7 mil Nm^3/year	8.3 mil Nm^3/year
Digester	(3×1000) 3000 m^3	(2×2500) 5000 m^3	(3×2400) 7200 m^3	(4×2500) 1000 m^3
Vehicles (vacuum tankers)	1×20 m^3	2×20 m^3	3×20 m^3	4×20 m^3
Cost of Vehicles	0.2 mil €	0.4 mil €	0.6 mil €	1.0 mil €
Cost of Biogas Plant	2.8 mil €	5.5 mil €	7.9 mil €	9.6 mil €
Investment costs per m^3/year for processed biomass	82€/m^3	55 €/m^3	44 €/m^3	37 €/m^3
Total Cost	3.0 mil €	5.9 mil €	8.5 mil €	10.6 mil €

5 ECONOMIC POTENTIAL FOR CHP IN CYPRUS

5.1 Economic Potential for CHP in Industry and the Tertiary Sector

5.1.1 Methodology

Preliminary feasibility studies were conducted within the scope of the project with regard to setting up cogeneration systems in more than 60 undertakings in the country's industrial and tertiary sectors.

The studies were based on data collected from the undertakings by means of questionnaires. The studies were analytical and conducted with the help of the computational model developed by taking into consideration all economic and technical data describing the investment. We can, therefore, claim that, on the basis, of course, of the information provided by the undertakings, the results of the study reflect the actual technical and economic potential for cogeneration in our sample. The financial viability of such an investment was evaluated from the perspective of a private investor.

The financial viability of cogeneration investments was studied with regard to:
- the annual operational benefits derived from saving fuel from thermal energy generated using a conventional boiler, from replacing electric energy and power market and from the revenue gained from the sale of surplus electricity;
- the cost of constructing and operating the cogeneration system.

Cogeneration systems were selected on the basis of:
- the types of process and the quality of thermal energy required by each undertaking;
- the ratio of electricity to heat;
- the time distribution of loads;
- the fuel available;
- the size and cost of the system.

The dimensioning of the proposed cogeneration systems was based strictly on the heat loads of each undertaking (so as to fully meet demand) and, following that, on electrical loads. The possibility of meeting part of or the entire cooling load demand was also examined in a number of cases. All cases examined in the industrial and tertiary sectors were autoproducers.

Economic indicators usually employed to study the feasibility of a cogeneration system are net present value (*NPV*), internal rate of return (*IRR*) and payback period (discounted *[DPB]* or simple *[SPB]*).

The basic data and results of the study are presented in the table below.

Table 5.1.1: Data and Results of Preliminary Feasibility Studies

<table>
<tr>
<td>

<u>Economic Data</u>

Economic life of investment
Desired rate of return
Depreciations
Book value
Investor’s tax rate
Subsidies
Loans – loan terms
Construction duration
Equipment, operating and maintenance costs of cogeneration system
Fuel costs
Data on purchase and sale of electricity
Economic life, desired rate of return

</td>
<td>

<u>Results (for private investors)</u>

Benefits from proposed system’s production (thermal, cooling and electrical load demands met, electricity sold)
Operating and maintenance costs
Benefit-cost table
Capital structure table
Investment cash flow table
Basic financial viability indicators (Net present value, internal rate of return, benefit/cost ratio, dynamic payback period)

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<tr>
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<u>Technical Data</u>

Heat, cooling and electrical loads
Data on operation of current system
Data on operation of cogeneration system
Data on operation of absorption cooling cycle

</td>
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</table>

Assumptions

The most important assumptions made during the preliminary feasibility studies on the installation of cogeneration systems at undertakings in the sample were that:

1. The studies were based on heat and electricity consumption data provided by the undertakings. It is not the purpose of this paper to explore energy-saving possibilities in the undertakings before installing a cogeneration system.
2. The studies were based on monthly heat and electrical loads.
3. Cogeneration system costs were not based on specific offers but, rather, obtained from published data and a limited survey of the Greek market. Some systems may be found at much lower prices. In any event, a parametric analysis of the cogeneration system investment’s sustainability in relation to its capital subsidy, which is part of this study, will help us draw conclusions on the economic potential for cogeneration.

Study results

The economic potential for cogeneration in the industrial and tertiary sectors was determined by processing all results obtained from the preliminary feasibility studies conducted on the installation of cogeneration systems at undertakings of the sample. The cogeneration potential of undertakings in the sample was extrapolated to include their entire sectors with the use of thermal energy consumption figures (data available from energy balances). The results are given in the form of a parametric analysis of installed cogeneration capacity in the industrial sectors in relation to the investment’s subsidy rate, cost of fuel, cost of purchasing electricity and dynamic payback period. The reasoning behind the tables and diagrams below is as follows:

There are three parametric analyses: the first deals with the investment’s subsidy rate, the second with fuel price variations and the third with variations in the selling price of electricity. The fuel price controls and fuel cost adjustments for the year 2007 have not been taken into consideration in the calculations. More specifically:

1. A separate parametric analysis for each sector of economic activity included in the sample and one for all the sectors together, **with the investment’s subsidy rate as a variable (**0% - 15% -

25% - 35%- 40% - 50% - 60%**).** In the analysis, reference values were used for FIT (11 eurocents/kWh) and the cost of fuel (2007 prices as shown below).

2. A separate parametric analysis for each sector of economic activity included in the sample and one for all the sectors together, **with fuel cost as a variable (**-50% to +50% of the reference scenario price in 10% increments**).** In the analysis, reference values were used for FIT (11 eurocents/kWh) and the investment subsidy rate (0%).
3. A separate parametric analysis for each sector of economic activity included in the sample and one for all the sectors together, **with FIT as a variable (**7 eurocents/kWh – 20 eurocent/kWh in 1 eurocent increments**).** In the analysis, reference values were used for the cost of fuel (2007 prices as shown below) and the investment subsidy rate (0%).

Parametric Analysis Input Data

Investor tax rate: **10%**

Subsidy rate: **0%**

Average selling price of electricity to the grid – FIT **0.11€ per kWh**

Fuel Prices

Fuel	Unit	Average 2007 Price
Heating diesel	€ / 1000 litres	787
LPG	€ / 1000 kilos	887.75
LFO, sulphur <1%	€ / 1000 kilos	450.83
HFO	€ / 1000 kilos	315.19
Agricultural oil	€ / 1000 litres	585.50
Olive cake	€ / 1000 kilos	34.17
Petroleum-coke	€ / 1000 kilos	69.6

Purchase price of electricity from the grid

Rates	Average electricity price in 2007 (€/kWh) – VAT and RES duty (0.22 eurocent/kWh) included
Household	0.14878
Commercial	0.15546
Industrial	0.13404
Agricultural	0.13640
Street Lighting	0.13129

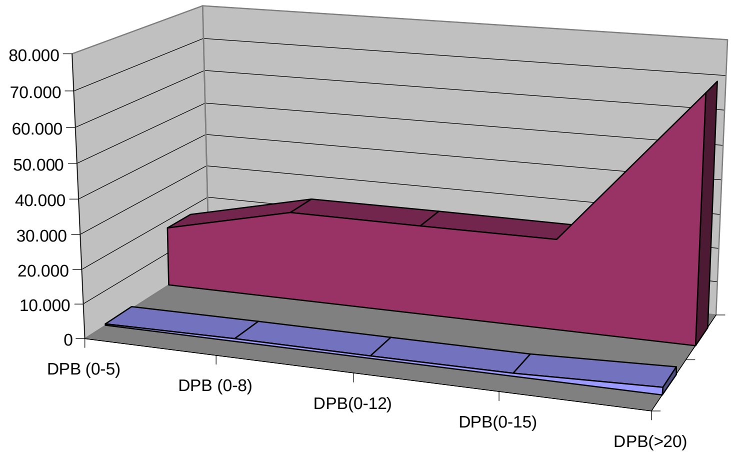
5.1.2 Parametric Analysis of Economic Potential for Cogeneration in Industrial Sectors

5.1.2.1 Agriculture – Animal Production

kWe					
Subsidisation	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
0%	17757	26294	26294	26294	70686
15%	17757	26294	70686	70686	70686
25%	17757	26294	70686	70686	70686
35%	26294	70686	70686	70686	70686
40%	26294	70686	70686	70686	70686
50%	50197	70686	70686	70686	70686
60%	70686	70686	70686	70686	70686

kWe					
Fuel cost variations	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
-50%	26294	26294	50197	70686	70686
-40%	26294	26294	50197	50197	70686
-30%	26294	26294	50197	50197	70686
-20%	26294	26294	26294	50197	70686
-10%	17757	26294	26294	50197	70686
0% (Ref)	17757	26294	26294	26294	70686
10%	17757	17757	17757	26294	70686
20%	0	17757	17757	17757	70686
30%	0	17757	17757	17757	70686
40%	0	17757	17757	17757	70686
50%	0	17757	17757	17757	70686

kWe					
Electricity selling price variations (€/kWh)	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
0.07	0	17757	17757	17757	70686
0.08	0	17757	17757	17757	70686
0.09	17757	17757	17757	17757	70686
0.10	17757	17757	17757	26294	70686
0.11	17757	26294	26294	26294	70686
0.12	17757	26294	26294	46783	70686
0.13	26294	26294	46783	70686	70686
0.14	26294	26294	46783	70686	70686
0.15	26294	26294	46783	70686	70686
0.16	26294	46783	46783	70686	70686
0.17	26294	46783	46783	70686	70686
0.18	26294	46783	46783	70686	70686
0.19	26294	46783	46783	70686	70686
0.20	26294	46783	46783	70686	70686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DPB (0-5)
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DPB(>20)

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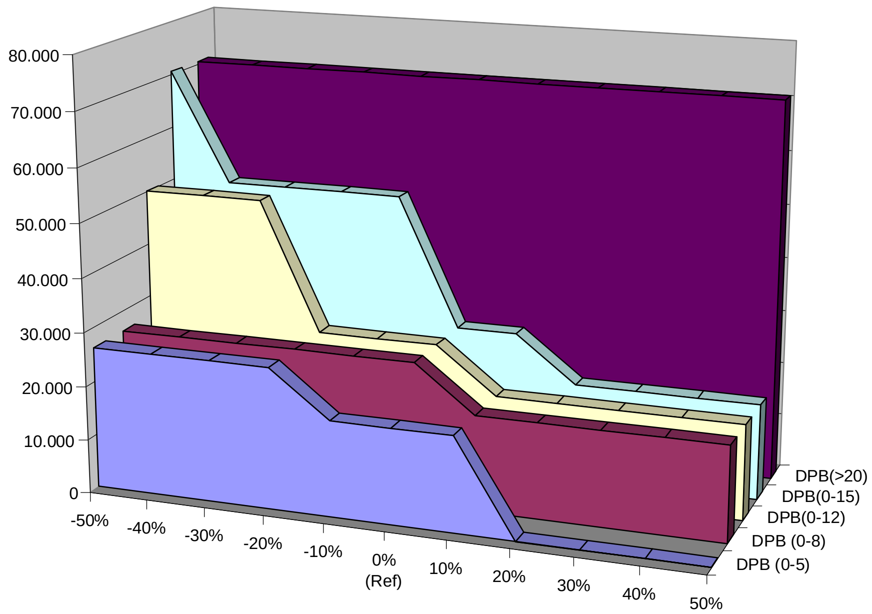
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-50%
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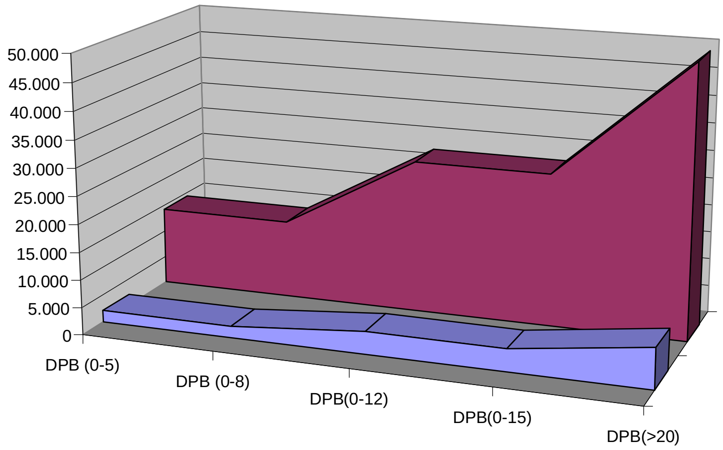
20%
30%
40%
50%
DPB(>20)
DPB(0-15)
DPB(0-12)
DPB (0-8)
DPB (0-5)

5.1.2.2 Food Products – Beverages

kWe					
Subsidisation	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
0%	14203	14203	27731	27731	49374
15%	14203	27731	33141	41934	49374
25%	14203	27731	41934	41934	49374
35%	27731	33141	41934	41934	49374
40%	27731	41934	41934	41934	49374
50%	29760	41934	41934	41934	49374
60%	41934	41934	49374	49374	49374

kWe					
Fuel cost variations	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
-50%	14203	29760	49374	49374	49374
-40%	14203	29760	49374	49374	49374
-30%	14203	29760	33141	41934	49374
-20%	14203	27731	29760	41934	49374
-10%	14203	14203	29760	33141	49374
0% (Ref)	14203	14203	27731	27731	49374
10%	9807	14203	27731	27731	49374
20%	9807	14203	27731	27731	49374
30%	9807	14203	14203	27731	49374
40%	3382	14203	14203	14203	49374
50%	3382	9807	14203	14203	49374

kWe					
Electricity selling price variations (€/kWh)	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
0.07	14203	14203	27731	27731	49374
0.08	14203	14203	27731	27731	49374
0.09	14203	14203	27731	27731	49374
0.10	14203	14203	27731	27731	49374
0.11	14203	14203	27731	27731	49374
0.12	14203	14203	27731	27731	49374
0.13	14203	14203	27731	31112	49374
0.14	14203	14203	27731	31112	49374
0.15	14203	14203	27731	31112	49374
0.16	14203	14203	31112	38552	49374
0.17	14203	14203	38552	38552	49374
0.18	14203	14203	38552	47345	49374
0.19	14203	14203	38552	47345	49374
0.20	14203	21643	38552	47345	49374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DPB (0-5)
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DPB(0-15)
DPB(>20)

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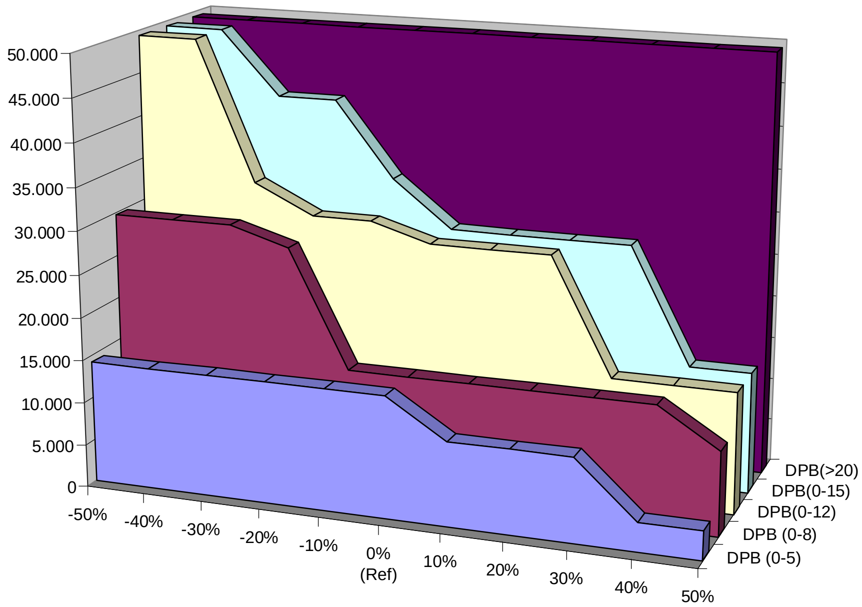
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-30%
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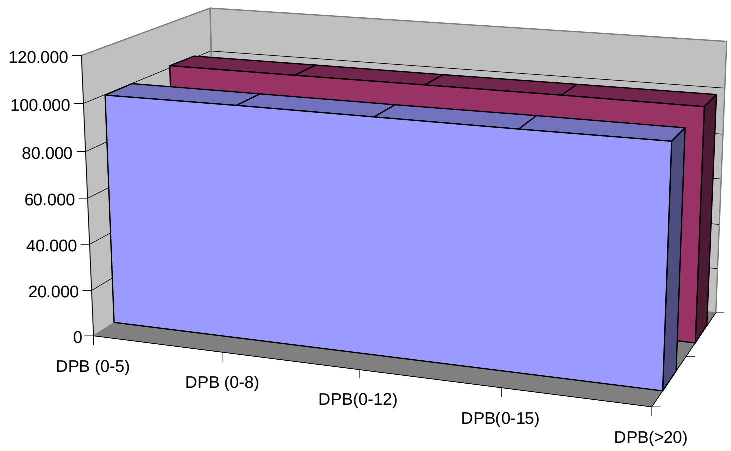
-10%
0% (Ref)
10%
20%
30%
40%
50%
DPB(>20)
DPB(0-15)
DPB(0-12)
DPB (0-8)
DPB (0-5)

5.1.2.3 Non-metallic mineral products

kWe					
Subsidisation	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
0%	100882	100882	100882	100882	100882
15%	100882	100882	100882	100882	100882
25%	100882	100882	100882	100882	100882
35%	100882	100882	100882	100882	100882
40%	100882	100882	100882	100882	100882
50%	100882	100882	100882	100882	100882
60%	100882	100882	100882	100882	100882

kWe					
Fuel cost variations	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
-50%	100882	100882	100882	100882	100882
-40%	100882	100882	100882	100882	100882
-30%	100882	100882	100882	100882	100882
-20%	100882	100882	100882	100882	100882
-10%	100882	100882	100882	100882	100882
0% (Ref)	100882	100882	100882	100882	100882
10%	100882	100882	100882	100882	100882
20%	100882	100882	100882	100882	100882
30%	100882	100882	100882	100882	100882
40%	100882	100882	100882	100882	100882
50%	100882	100882	100882	100882	100882

kWe					
Electricity selling price variations (€/kWh)	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
0.07	95838	100882	100882	100882	100882
0.08	98360	100882	100882	100882	100882
0.09	100882	100882	100882	100882	100882
0.10	100882	100882	100882	100882	100882
0.11	100882	100882	100882	100882	100882
0.12	100882	100882	100882	100882	100882
0.13	100882	100882	100882	100882	100882
0.14	100882	100882	100882	100882	100882
0.15	100882	100882	100882	100882	100882
0.16	100882	100882	100882	100882	100882
0.17	100882	100882	100882	100882	100882
0.18	100882	100882	100882	100882	100882
0.19	100882	100882	100882	100882	100882
0.20	100882	100882	100882	100882	100882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100.000
80.000
60.000
40.000
20.000
0
DPB (0-5)
DPB (0-8)
DPB(0-12)
DPB(0-15)
DPB(>20)

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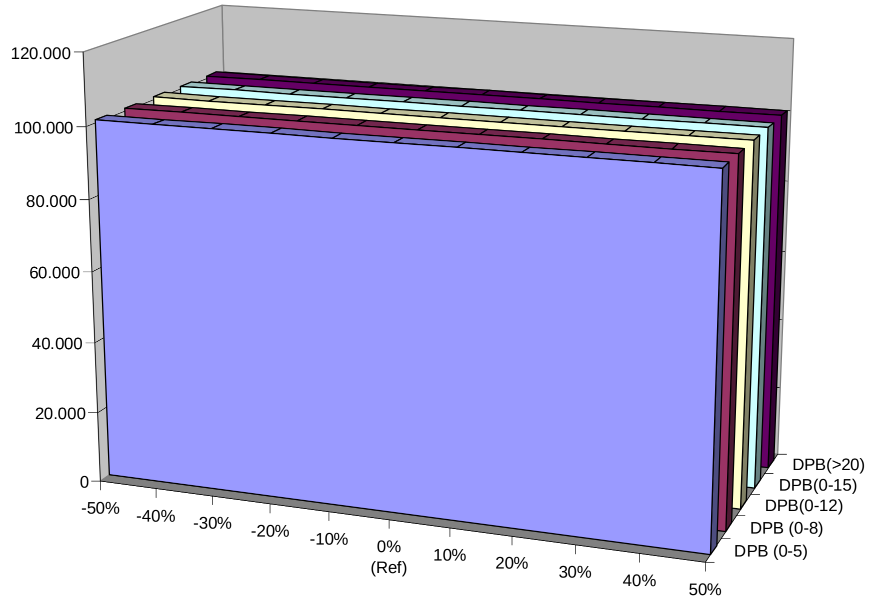
120.000
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-50%
-40%
-30%
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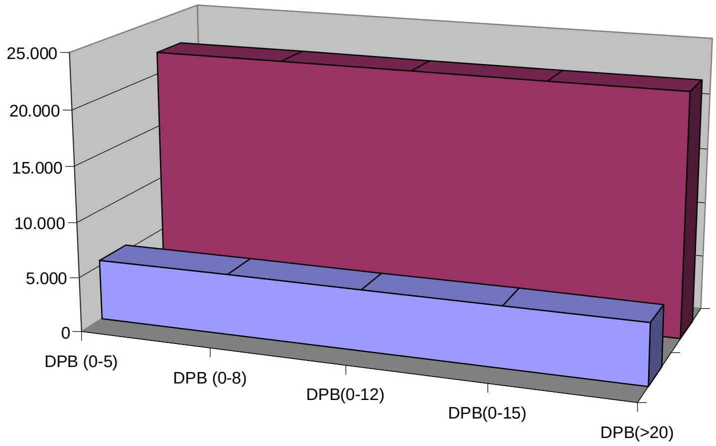
0%
(Ref)
10%
20%
30%
40%
50%
DPB(>20)
DPB(0-15)
DPB(0-12)
DPB (0-8)
DPB (0-5)

5.1.2.4 Non-ferrous metal ores

kWe					
Subsidisation	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
0%	22000	22000	22000	22000	22000
15%	22000	22000	22000	22000	22000
25%	22000	22000	22000	22000	22000
35%	22000	22000	22000	22000	22000
40%	22000	22000	22000	22000	22000
50%	22000	22000	22000	22000	22000
60%	22000	22000	22000	22000	22000

kWe					
Fuel cost variations	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
-50%	22000	22000	22000	22000	22000
-40%	22000	22000	22000	22000	22000
-30%	22000	22000	22000	22000	22000
-20%	22000	22000	22000	22000	22000
-10%	22000	22000	22000	22000	22000
0% (Ref)	22000	22000	22000	22000	22000
10%	22000	22000	22000	22000	22000
20%	22000	22000	22000	22000	22000
30%	22000	22000	22000	22000	22000
40%	22000	22000	22000	22000	22000
50%	22000	22000	22000	22000	22000

kWe					
Electricity selling price variations (€/kWh)	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
0.07	22000	22000	22000	22000	22000
0.08	22000	22000	22000	22000	22000
0.09	22000	22000	22000	22000	22000
0.10	22000	22000	22000	22000	22000
0.11	22000	22000	22000	22000	22000
0.12	22000	22000	22000	22000	22000
0.13	22000	22000	22000	22000	22000
0.14	22000	22000	22000	22000	22000
0.15	22000	22000	22000	22000	22000
0.16	22000	22000	22000	22000	22000
0.17	22000	22000	22000	22000	22000
0.18	22000	22000	22000	22000	22000
0.19	22000	22000	22000	22000	22000
0.20	22000	22000	22000	22000	22000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DPB (0-5)
DPB (0-8)
DPB(0-12)
DPB(0-15)
DPB(>20)

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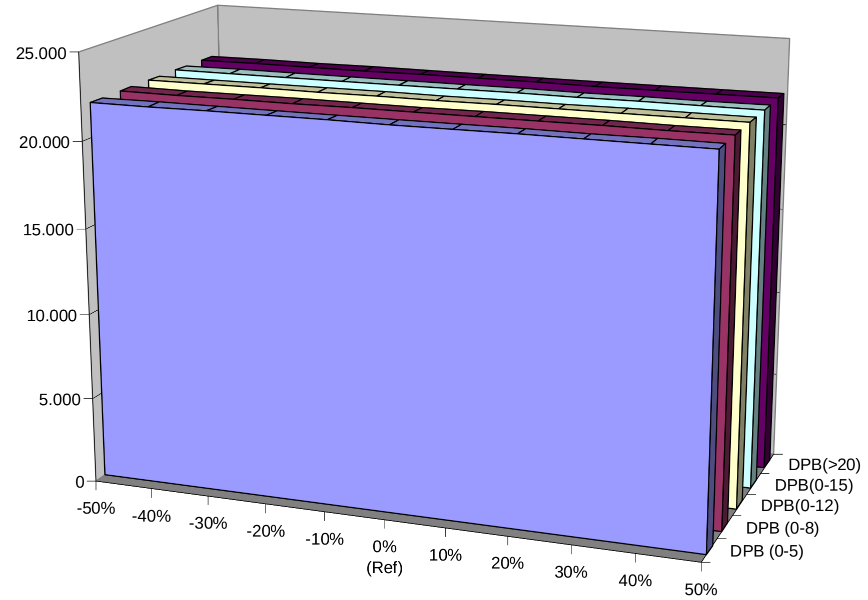
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20.000
15.000
10.000
5.000
0
-50%
-40%
-30%
-20%
-10%
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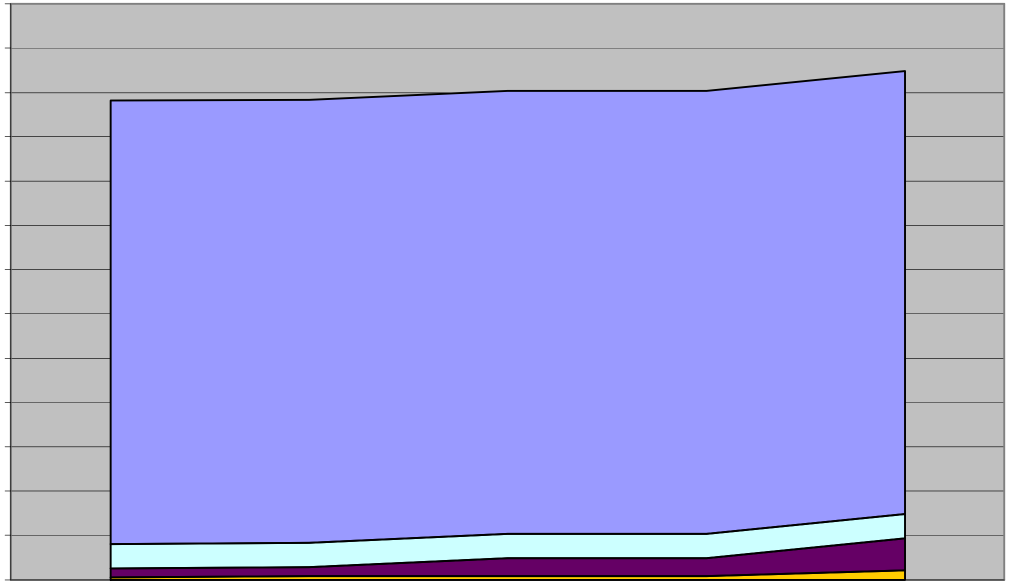
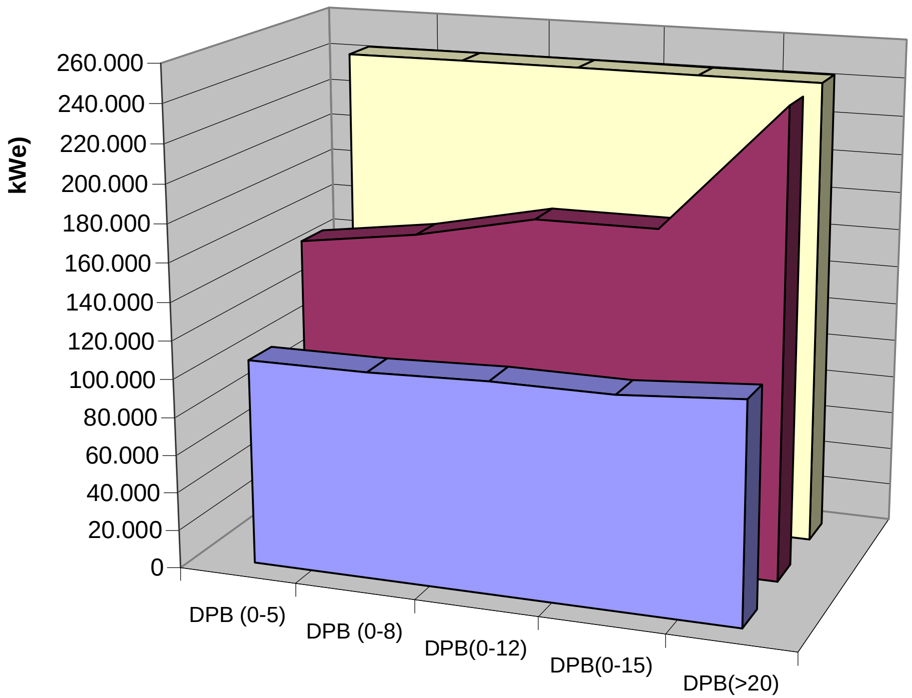
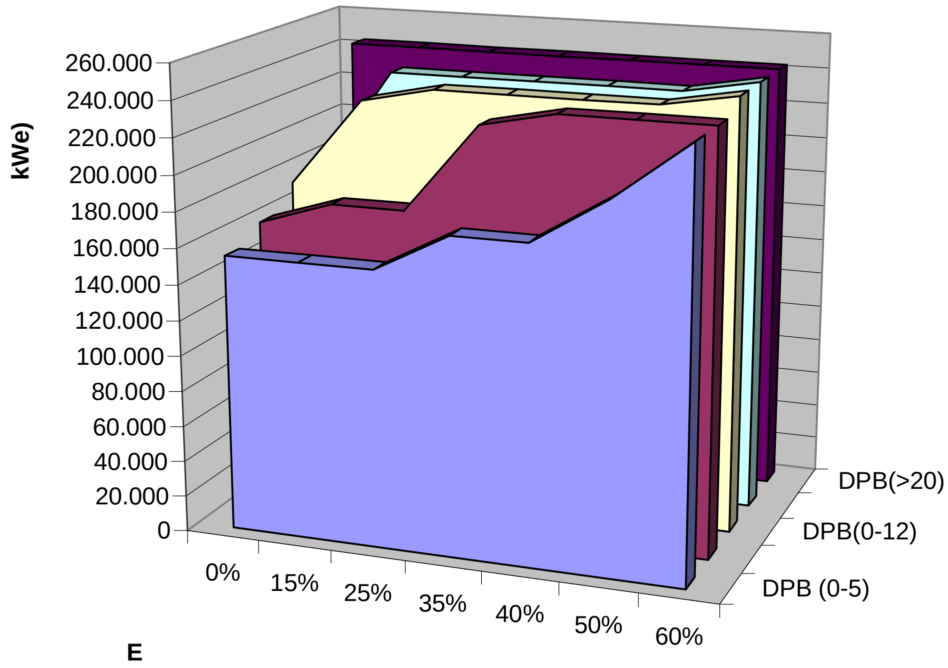
(Ref)
10%
20%
30%
40%
50%
DPB(>20)
DPB(0-15)
DPB(0-12)
DPB (0-8)
DPB (0-5)

5.1.2.5 Total Industry




kWe)
260.000
240.000
220.000
200.000
180.000
160.000
140.000
120.000
100.000
80.000
60.000
40.000
20.000
0
DPB (0-5)
DPB (0-8)
DPB(0-12)
DPB(0-15)
DPB(>20)


kWe)
260.000
240.000
220.000
200.000
180.000
160.000
140.000
120.000
100.000
80.000
60.000
40.000
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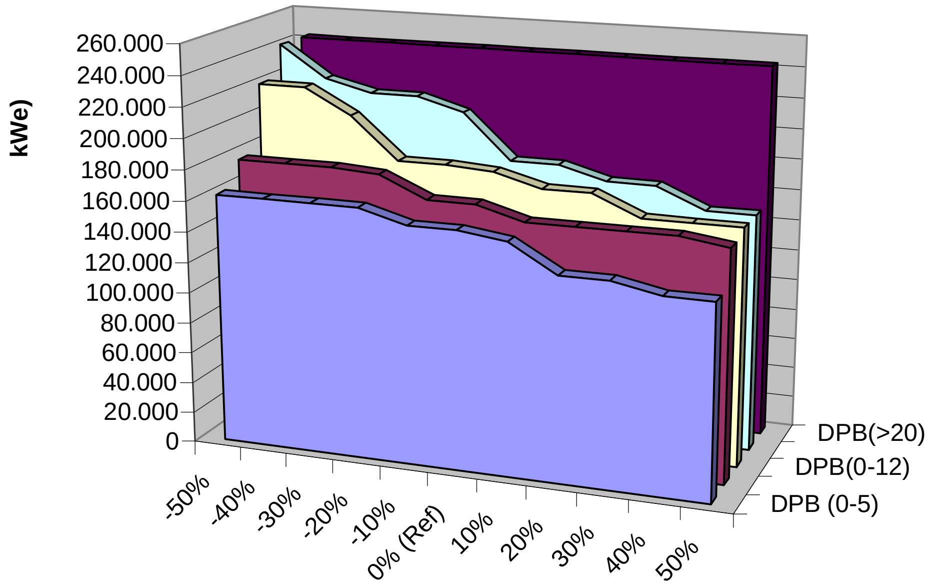
0
0%
15%
25%
35%
40%
50%
60%
E
DPB(>20)
DPB(0-12)
DPB (0-5)


kWe)
260.000
240.000
220.000
200.000
180.000
160.000
140.000
120.000
100.000
80.000
60.000
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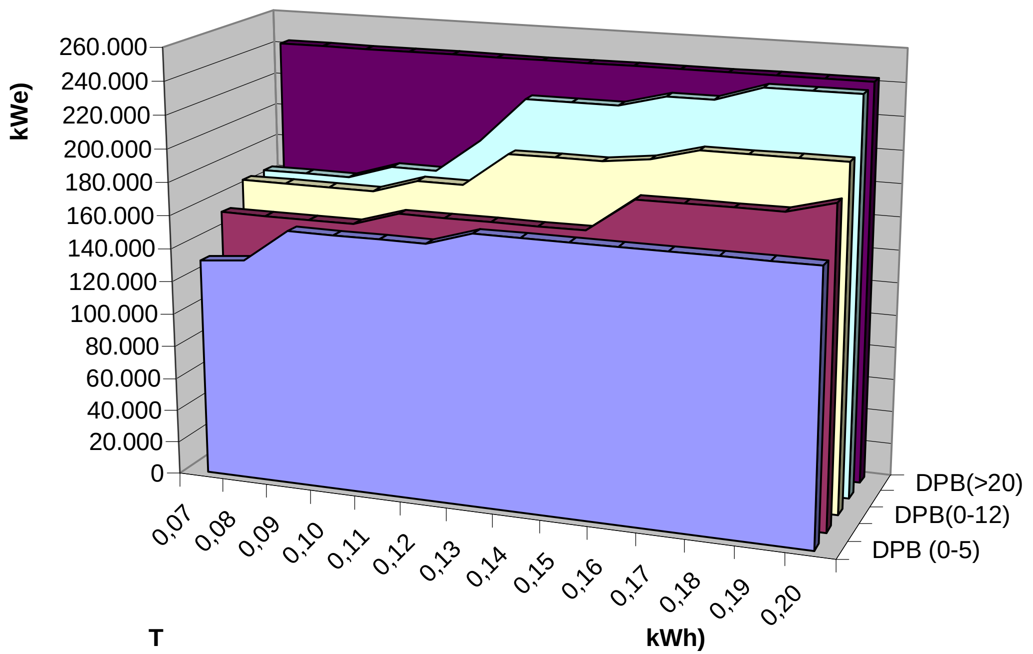
-50%
-40%
-30%
-20%
-10%
0% (Ref)
10%
20%
30%
40%
50%
DPB(>20)
DPB(0-12)
DPB (0-5)



	0,070	0,080	0,090	0,100	0,110	0,120	0,130	0,140	0,150	0,160	0,170	0,180	0,190	0,200
DPB (0-5)	132041	134563	154842	154842	154842	154842	163379	163379	163379	163379	163379	163379	163379	163379
DPB (0-8)	154842	154842	154842	154842	163379	163379	163379	163379	163379	183868	183868	183868	183868	191308
DPB(0-12)	168369	168369	168369	168369	176906	176906	197395	197395	197395	200777	208217	208217	208217	208217
DPB(0-15)	168369	168369	168369	176906	176906	197395	224680	224680	224680	232120	232120	240913	240913	240913
DPB(>20)	242942	242942	242942	242942	242942	242942	242942	242942	242942	242942	242942	242942	242942	242942

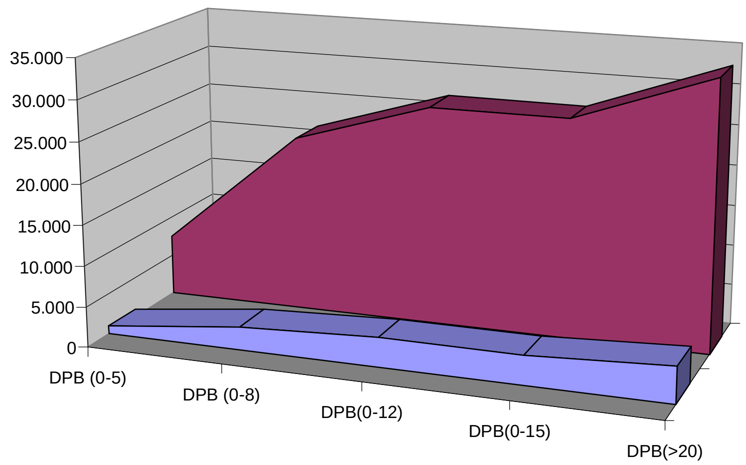
5.1.3 Parametric Analysis of CHP Potential in the Tertiary Sector

5.1.3.1 Parametric Analysis of CHP Economic Potential of Hotels

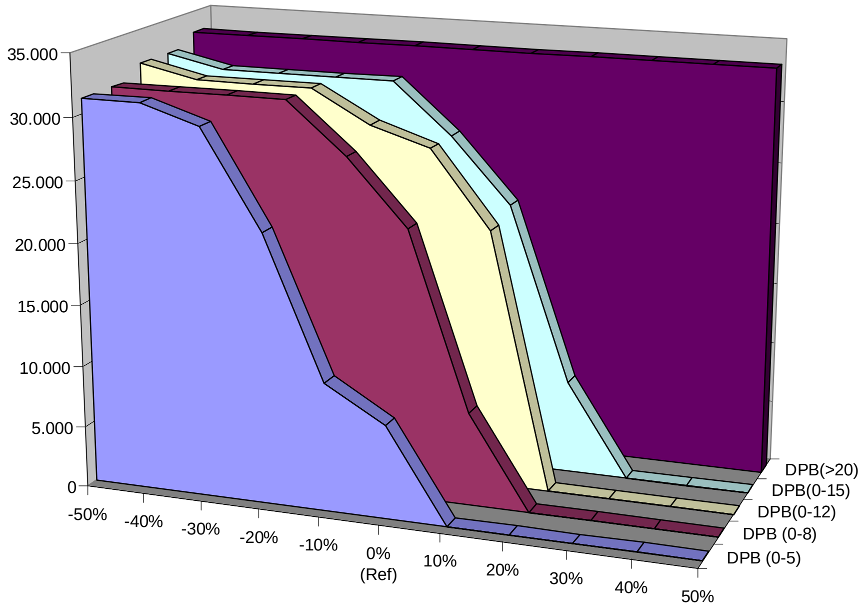
	kWe				
Subsidisation	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
0%	7516	21797	27059	27059	33222
15%	9320	21797	27059	27059	33222
25%	20895	27059	27059	28562	33222
35%	21797	27059	28562	28562	33222
40%	21797	27059	28562	28562	33222
50%	27059	28562	28562	28562	33222
60%	28562	28562	31193	31193	33222

	kWe				
Fuel cost variations	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
-50%	31193	31193	32245	32245	33222
-40%	31193	31193	31193	31193	33222
-30%	29689	31193	31193	31193	33222
-20%	21797	31193	31193	31193	33222
-10%	10372	27059	28562	31193	33222
0% (Ref)	7516	21797	27059	27059	33222
10%	0	7516	20895	21797	33222
20%	0	0	0	7516	33222
30%	0	0	0	0	33222
40%	0	0	0	0	33222
50%	0	0	0	0	33222

	kWe				
Electricity selling price variations (€/kWh)	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
0.07	0	10372	20895	21797	33222
0.08	7516	10372	21797	21797	33222
0.09	7516	20895	21797	27059	33222
0.10	7516	20895	21797	27059	33222
0.11	7516	21797	27059	27059	33222
0.12	7516	21797	27059	27059	33222
0.13	7516	21797	27059	27059	33222
0.14	7516	21797	27059	27059	33222
0.15	7516	21797	27059	27059	33222
0.16	7516	21797	27059	27059	33222
0.17	7516	21797	27059	29689	33222
0.18	18941	27059	27059	29689	33222
0.19	18941	27059	29689	29689	33222
0.20	18941	27059	29689	29689	33222


35.000
30.000
25.000
20.000
15.000
10.000
5.000
0
DPB (0-5)
DPB (0-8)
DPB(0-12)
DPB(0-15)
DPB(>20)

……

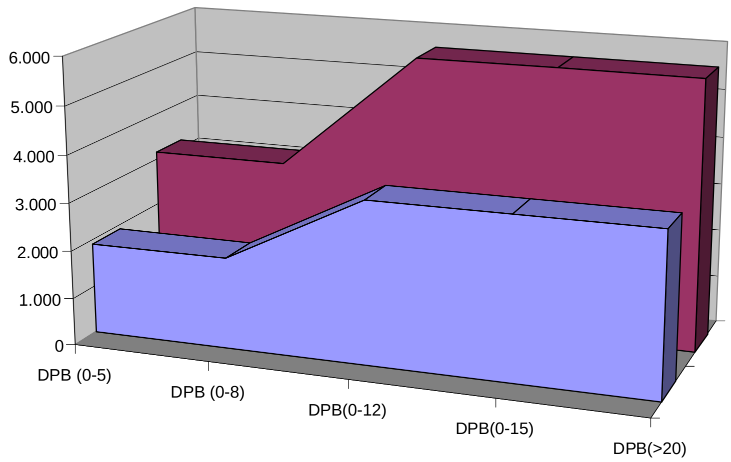

35.000
30.000
25.000
20.000
15.000
10.000
5.000
0
-50%
-40%
-30%
-20%
-10%
0%
(Ref)
10%
20%
30%
40%
50%
DPB(>20)
DPB(0-15)
DPB(0-12)
DPB (0-8)
DPB (0-5)

5.1.3.2 Parametric Analysis of CHP Economic Potential of Hospitals

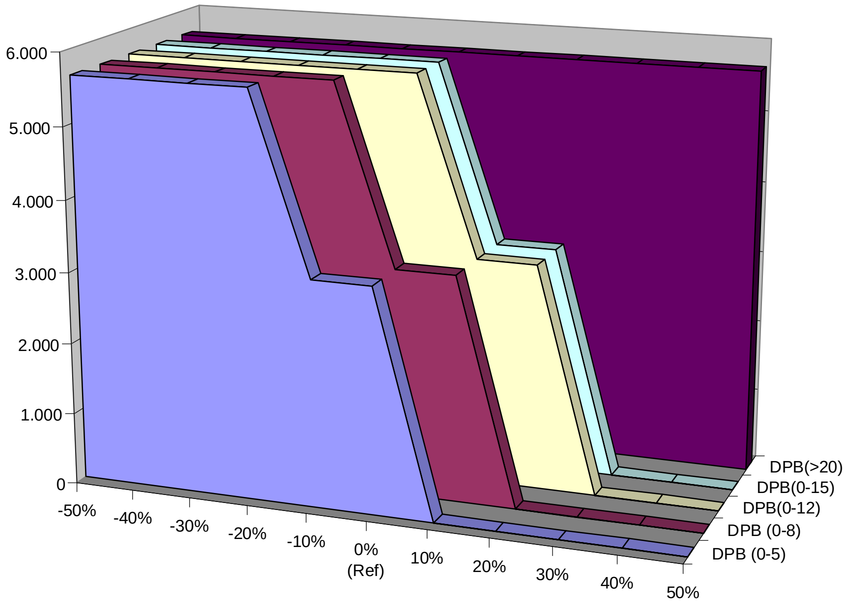
kWe					
Subsidisation	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
0%	3158	3158	5651	5651	5651
15%	3158	5651	5651	5651	5651
25%	3158	5651	5651	5651	5651
35%	5651	5651	5651	5651	5651
40%	5651	5651	5651	5651	5651
50%	5651	5651	5651	5651	5651
60%	5651	5651	5651	5651	5651

kWe					
Fuel cost variations	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
-50%	5651	5651	5651	5651	5651
-40%	5651	5651	5651	5651	5651
-30%	5651	5651	5651	5651	5651
-20%	5651	5651	5651	5651	5651
-10%	3158	5651	5651	5651	5651
0% (Ref)	3158	3158	5651	5651	5651
10%	0	3158	3158	3158	5651
20%	0	0	3158	3158	5651
30%	0	0	0	0	5651
40%	0	0	0	0	5651
50%	0	0	0	0	5651

kWe					
Electricity selling price variations (€/kWh)	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
0.07	3158	3158	5651	5651	5651
0.08	3158	3158	5651	5651	5651
0.09	3158	3158	5651	5651	5651
0.10	3158	3158	5651	5651	5651
0.11	3158	3158	5651	5651	5651
0.12	3158	3158	5651	5651	5651
0.13	3158	3158	5651	5651	5651
0.14	3158	3158	5651	5651	5651
0.15	3158	3158	5651	5651	5651
0.16	3158	3158	5651	5651	5651
0.17	3158	3158	5651	5651	5651
0.18	3158	3158	5651	5651	5651
0.19	3158	3158	5651	5651	5651
0.20	3158	3158	5651	5651	5651


6.000
5.000
4.000
3.000
2.000
1.000
0
DPB (0-5)
DPB (0-8)
DPB(0-12)
DPB(0-15)
DPB(>20)

……

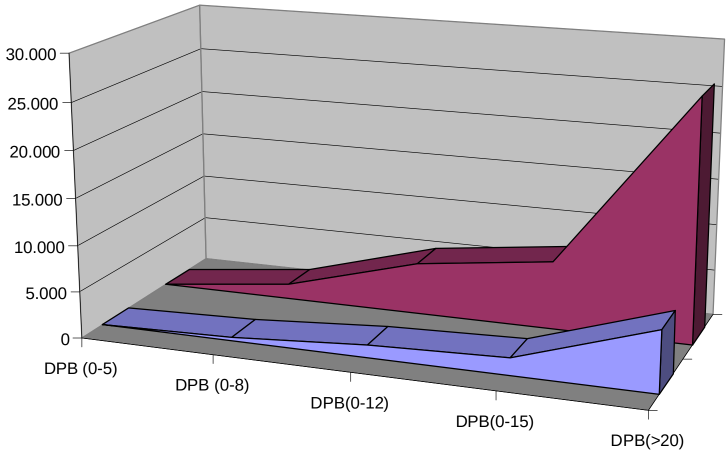

6.000
5.000
4.000
3.000
2.000
1.000
0
-50%
-40%
-30%
-20%
-10%
0%
(Ref)
10%
20%
30%
40%
50%
DPB(>20)
DPB(0-15)
DPB(0-12)
DPB (0-8)
DPB (0-5)

5.1.3.3 Parametric Analysis of CHP Economic Potential of Commercial Buildings

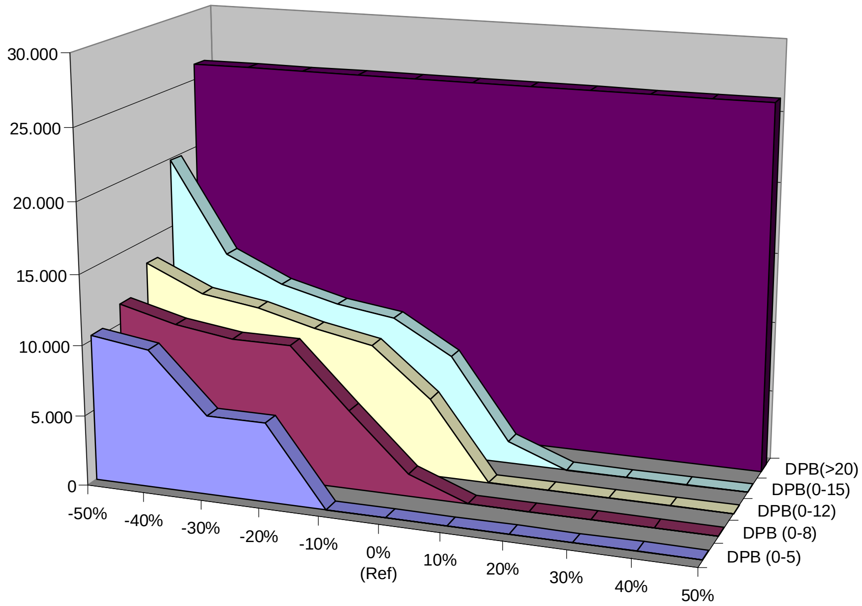
	kWe				
Subsidisation	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
0%	0	1594	5579	7372	26142
15%	0	5579	7372	7372	26142
25%	0	5579	7372	9205	26142
35%	5579	7372	10002	10002	26142
40%	5579	7372	10002	10002	26142
50%	7372	10002	10002	15263	26142
60%	9205	10002	15860	17455	26142

	kWe				
Fuel cost variations	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
-50%	10361	11437	13270	19846	26142
-40%	9763	10361	11437	13270	26142
-30%	5579	9763	10839	11437	26142
-20%	5579	9763	9763	10361	26142
-10%	0	5579	8966	9763	26142
0% (Ref)	0	1594	5579	7372	26142
10%	0	0	0	1594	26142
20%	0	0	0	0	26142
30%	0	0	0	0	26142
40%	0	0	0	0	26142
50%	0	0	0	0	26142

	kWe				
Electricity selling price variations (€/kWh)	DPB (0-5)	DPB (0-8)	DPB(0-12)	DPB(0-15)	DPB(>20)
0.07	0	1594	5579	7372	26142
0.08	0	1594	5579	7372	26142
0.09	0	1594	5579	7372	26142
0.10	0	1594	5579	7372	26142
0.11	0	1594	5579	7372	26142
0.12	0	1594	5579	7372	26142
0.13	0	5579	5579	7372	26142
0.14	0	5579	5579	7372	26142
0.15	0	5579	5579	12154	26142
0.16	0	5579	10361	12154	26142
0.17	0	5579	10361	12154	26142
0.18	0	5579	10361	12154	26142
0.19	0	10361	10361	12154	26142
0.20	0	10361	10361	12154	26142


30.000
25.000
20.000
15.000
10.000
5.000
0
DPB (0-5)
DPB (0-8)
DPB(0-12)
DPB(0-15)
DPB(>20)

……


30.000
25.000
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15.000
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0
-50%
-40%
-30%
-20%
-10%
0%
(Ref)
10%
20%
30%
40%
50%
DPB(>20)
DPB(0-15)
DPB(0-12)
DPB (0-8)
DPB (0-5)

5.1.4 Prefeasibility Studies on CHP Potential in Industry and the Tertiary Sector

Introduction
This section includes four preliminary viability studies on the installation of CHP systems in the following undertakings:

1. **FOUR SEASONS HOTEL, trigeneration**
2. **CENTRAL BANK BUILDING, trigeneration**
3. **LIMASSOL GENERAL HOSPITAL, trigeneration**
4. **LEDRA BRICK FACTORY LTD, trigeneration**

These studies were conducted by EXERGIA S.A. in cooperation with the Centre for Renewable Energy Sources as part of the "Analysis of the National Potential for Cogeneration" Project financed by the Energy Service of the Ministry of Commerce, Industry and Tourism in Cyprus.

The studies comprised the following steps:
§ Data were collected with the assistance of each undertaking's executive officers.
§ The data was then analysed using a computational programme developed specifically for this purpose by EXERGIA.
§ A report was compiled and the competent bodies informed accordingly.

Method of Analysis
Use was made of the evaluation method described in the following book:

HEAT AND ELECTRICITY COGENERATION
C. A. FRANGOPOULOS, I. P. KARYDOGIANNIS, G. K. KARALIS
GREEK PRODUCTIVITY CENTRE (ELKEPA), ATHENS 1994

Based on this method, a computer programme was developed to perform economic evaluation of the data. The computer programme is briefly described in the paragraph below.

Description of programme
The programme was developed using EXCEL and calculates the basic financial viability indicators of the investment, i.e. net present value (NPV), internal rate of return (IRR), benefit/cost ratio (B/C), dynamic payback period (DPB), as well as a Cash Flow Chart for the investment. The investment's annual net gains, which depend on annual operating gains, loan instalments and equipment depreciation, have been taken into account when calculating the figures above.

Data and results
The study data can be grouped in three categories:
1. General economic data concerning capital structure (own capital, subsidies, loans), economic life of investment, desired rate of return, etc.
2. Energy data of undertaking (operating hours, electrical and thermal needs, fluctuations in available heat and electrical loads, energy costs, etc.)
3. Data on proposed cogeneration system (investment and operating costs, rate of return, fuels, etc.)

The cogeneration system was selected according to the quality of the required thermal energy and the ratio of heat loads to electrical loads. The system's dimensioning was based, mainly, on the undertaking's heat loads and, then, on its electrical loads.

The investment's financial viability depends on:
- the annual operational benefits derived from saving fuel from the generation of thermal energy using a conventional boiler, the replacement of the electricity and electrical power market and the revenue generated from the sale of surplus electricity.
- the cost of constructing and operating the cogeneration system.

The following have been taken into account when calculating CHP potential:
§ Capital subsidy obtained by each undertaking: 0%
§ Electricity generated by the cogeneration system and not consumed by the undertaking can be sold to the EAC at 11 eurocents/kWh
§ Fuel prices and electricity purchase prices are based on Table 1 and Table 2 below.

Table 1: Average fuel price for 2007

Fuel	Average price for 2007
Heating diesel	787.00 €/1000 litres
LPG	887.75 €/ton
LFO	450.83 €/ton
HFO	315.19 €/ton
Agricultural oil	585.50 €/1000 litres
Olive cake	34.17 €/ton
Pet-coke	69.6 €/ton

Table 2: Average electricity price for 2007 (VAT and RES duty [0.22 €cent/kWh] included)

Rates	Average electricity price 2007 (€cent/kWh)
Household	14.878
Commercial	15.546
Industrial	13.404
Agricultural	13.640
Street Lighting	13.129

Survey data and results for each application are presented below.

5.1.5.1 FOUR SEASONS HOTEL

Energy needs of undertaking

This study pertains to the FOUR SEASONS HOTEL. The hotel consumes approximately 7.9 GWh a year mainly for lighting, air conditioning, elevators, catering, etc. Electricity consumption increases during the summer months when cooling equipment is used.

Thermal energy is mainly used for heating the hotel's interior spaces and pool, for producing hot service water and for generating steam (10 bar) for the washing machines. Fuels used are diesel and liquefied petroleum gas.

The following have been taken into consideration for this study:

- The additional energy demand in the summer months is due to air conditioners.
- Thermal power demand in the summer months is considered to be the base heat load that remains constant throughout the year, while the additional demand during the winter season meets space heating needs.

The hotel is in operation 24 hours a day, 365 days a year.

Description of cogeneration system

1. System selection

The cogeneration system was selected based on:

- the types of process and the quality of thermal energy required
- the ratio of electricity to heat
- the time distribution of loads
- the fuel available
- the size and cost of the system.

Given the size and type of energy consumption at the undertaking, the cogeneration system selected is the reciprocating internal combustion engine (RICE). The thermal energy generated will be used to meet the hotel's thermal needs in the winter months. During the summer months there is surplus thermal energy, which will be used in cooling equipment operating on an absorption cycle to meet the hotel's air conditioning needs.

2. System dimensioning

The system's dimensioning was based on the hotel's heat and cooling loads. The installation of a 1000 kWe RICE cogeneration system and a 586 kWc absorption chiller is being examined. The absorption chiller will be operating in the summer months on the surplus thermal energy generated. There is no thermal energy surplus in the winter given the higher demand due to the hotel's heating requirements. The operation of the system will meet the hotel's heat load demands in full and its cooling load demands in part, while 100% of the electricity generated will be used by the hotel in the summer, and 82% in the winter.

3. Cost of system

The proposed system consists of a reciprocating internal combustion engine, an electric generator and an absorption chiller. The system's estimated total cost is 1.1 million euros.

4. Fuel cost and quality

The fuel used will be diesel. Its cost has been assumed as 0.787 €/l.

5. Maintenance and operating costs

The system's maintenance and operating costs are estimated to be approximately €58,000 a year, which includes spare parts and man hours spent on system maintenance work and operation.

6. Numerical results

The study's data and results are shown in detail in the tables that follow:

Table 1: General Financial Data

GENERAL FINANCIAL DATA					
Economic life of investment		15	years		
Desirable rate of return (d)		10%			
Inflators					
	Fuel	0%			
	Labour and maintenance	0%			
Investor tax rate		10%			
Construction duration		1	years		
Investment cost distribution over construction years					
	year -3	0%			
	year -2				
	year -1	50%			
	start 0	50%			
DEPRECIATION				**RATE**	
	% of capital	100%	in	10	years
BOOK VALUE					
	% of capital	0%			
CAPITAL STRUCTURE					
Subsidies					
	year -3	0%	of investment cost		
	year -2	0%	of investment cost		
	year -1	0%	of investment cost		
Subsidised loans					
	year -3	0%	of investment cost		
	year -2	0%	of investment cost		
	year -1	0%	of investment cost		
Bank loans					
	year -3	0%	of investment cost		
	year -2	0%	of investment cost		
	year -1	0%	of investment cost		
LOAN TERMS					
Subsidised					
Duration		0	years		
Grace period		0	years		
Interest		0%			
Bank					
Duration		0	years		
Grace period		0	years		
Interest		0%			
ACCOUNTING PERIOD		15	years		

Table 2: Heat and electrical loads of undertaking

DATA - LOADS

Operating hours of undertaking – Heat and electricity needs

Month	Hours of operation	Heat required from fuel • (• J/h)	Heat required from fuel B (• J/h)	Electricity required for cooling (kWh/month)	Overall electricity required (kWh/month)
January	732	4,012	395	0	488,000
February	732	4,012	395	0	488,000
March	732	4,012	395	0	488,000
April	732	2,006	197	143,019	832,650
May	732	2,006	197	143,019	832,650
June	732	2,006	197	143,019	832,650
July	732	2,006	197	143,019	832,650
August	732	2,006	197	143,019	832,650
September	732	2,006	197	143,019	832,650
October	732	4,012	395	0	488,000
November	732	4,012	395	0	488,000
December	732	4,012	395	0	488,000
TOTAL	8,784			858,112	7,923,900

Table 3:Data on conventional system

DATA: CONVENTIONAL SYSTEM

	FUEL A		FUEL B	
Fuel	Diesel		LPG	
Boiler fuel unit cost	0.79	€/l	0.89	€/l
Lower heating value	44.80	• J/l	46.00	• J/l
Energy efficiency of conventional system (%)	80%		80%	

Table 4: Data on cogeneration system

Cogeneration technology	Reciprocating internal combustion engine	
Electrical power	1,000	kWe
Total efficiency	80%	
Electrical efficiency	32%	
Fuel type	Diesel	
Fuel unit cost	0.79	€/l
Lower heating value of fuel	44.80	• J/l
CHP system cost	1,000	€/ kWe
CHP system operating and maintenance cost	8	€/ • Wh
Absorption chiller capacity	586	kW cooling capacity
Absorption chiller cost	200	€/kW cooling capacity
Coefficient of performance (COP) of absorption chiller (%)	70%	
COP of conventional cooling equipment	3	

CHP SYSTEM OPERATION

Month	Load % (Assumption: heat/electricity ratio and efficiency remain constant when load decreases)	Hours of operation (system availability must be taken into account)
January	96%	622.2
February	96%	622.2
March	96%	622.2
April	100%	622.2
May	100%	622.2
June	100%	622.2
July	100%	622.2
August	100%	622.2
September	100%	622.2
October	96%	622.2
November	96%	622.2
December	96%	622.2

Table 5: Value of generated thermal energy

	Heat generated by CHP system per month (• J)	**Thermal energy required exclusively for heat loads per month (• J) (Fuel A)**	**Thermal energy required exclusively for heat loads per month (• J) (Fuel B)**	Thermal energy required for cooling per month (• J)	Maximum thermal energy absorbed by absorption chiller per month (MJ) (operation concurrent with CHP system)	Useful thermal energy absorbed by absorption chiller per month (MJ) (operation concurrent with CHP system)	Monthly thermal energy surplus after heat load demand (Fuel A) has been met by CHP system (MJ)
Jan.	**3,225,667**	**2,936,889**	**288,778**	0	0	0	288,778
Feb.	**3,225,667**	**2,936,889**	**288,778**	0	0	0	288,778
Mar.	**3,225,667**	**2,936,889**	**288,778**	0	0	0	288,778
Apr.	**3,359,880**	**1,468,444**	**144,389**	2,206,574	1,875,588	1,875,588	1,891,436
May	**3,359,880**	**1,468,444**	**144,389**	2,206,574	1,875,588	1,875,588	1,891,436
Jun.	**3,359,880**	**1,468,444**	**144,389**	2,206,574	1,875,588	1,875,588	1,891,436
Jul.	**3,359,880**	**1,468,444**	**144,389**	2,206,574	1,875,588	1,875,588	1,891,436
Aug.	**3,359,880**	**1,468,444**	**144,389**	2,206,574	1,875,588	1,875,588	1,891,436
Sept.	**3,359,880**	**1,468,444**	**144,389**	2,206,574	1,875,588	1,875,588	1,891,436
Oct.	**3,225,667**	**2,936,889**	**288,778**	0	0	0	288,778
Nov.	**3,225,667**	**2,936,889**	**288,778**	0	0	0	288,778
Dec.	**3,225,667**	**2,936,889**	**288,778**	0	0	0	288,778
TOTAL	**39,513,280**	**26,432,000**	**2,599,000**	13,239,445	11,253,528	11,253,528	13,081,280
Annual quantity of heat generated by CHP system for heating and cooling	**39,513,280**	**• J/year**					

Monthly thermal energy surplus after heat load demand (Fuel B) has been met by CHP system (MJ)	Monthly thermal energy surplus after heat and cooling load demand (Fuel A) has been met by CHP system (MJ)	Useful thermal energy generated per month by CHP system to meet heat load demand (Fuel A) (MJ)	Useful thermal energy generated per month by CHP system to meet heat load demand (Fuel B) (MJ)	Useful thermal energy generated per month by CHP system to meet cooling load demand (MJ)	Monthly gains from heat load demand (Fuel A) met with CHP system (€)	Monthly gains from heat load demand (Fuel B) met with CHP system (€)	Monthly gains from cooling load demand met with CHP system (€)	Percentage of total heat and cooling load needs met (%)
0	0	2,936,889	288,778	0	64,490	6,966	0	100%
0	0	2,936,889	288,778	0	64,490	6,966	0	100%
0	0	2,936,889	288,778	0	64,490	6,966	0	100%
1,747,047	0	1,468,444	144,389	1,747,047	32,245	3,483	17,603	88%
1,747,047	0	1,468,444	144,389	1,747,047	32,245	3,483	17,603	88%
1,747,047	0	1,468,444	144,389	1,747,047	32,245	3,483	17,603	88%
1,747,047	0	1,468,444	144,389	1,747,047	32,245	3,483	17,603	88%
1,747,047	0	1,468,444	144,389	1,747,047	32,245	3,483	17,603	88%
1,747,047	0	1,468,444	144,389	1,747,047	32,245	3,483	17,603	88%
0	0	2,936,889	288,778	0	64,490	6,966	0	100%
0	0	2,936,889	288,778	0	64,490	6,966	0	100%
0	0	2,936,889	288,778	0	64,490	6,966	0	100%
10,482,280	0	26,432,000	2,599,000	10,482,280	580,413	62,697	105,621	

Table 6: Calculation of Value of electricity generated

	Electricity generated by CHP system per month (kWh/month)	Electricity used for own consumption per month (kWh/month)	% of electricity generated by CHP system that is used for own consumption	Electricity sold per month (kWh/month)	Monthly savings on electricity costs thanks to CHP system (€/month)	Monthly income from sale of surplus electricity (€/month)
Jan.	597,346	488,000	82%	109,346	75,864	12,028
Feb.	597,346	488,000	82%	109,346	75,864	12,028
Mar.	597,346	488,000	82%	109,346	75,864	12,028
Apr.	622,200	622,200	100%	0	96,727	0
May	622,200	622,200	100%	0	96,727	0
Jun.	622,200	622,200	100%	0	96,727	0
Jul.	622,200	622,200	100%	0	96,727	0
Aug.	622,200	622,200	100%	0	96,727	0
Sept.	622,200	622,200	100%	0	96,727	0
Oct.	597,346	488,000	82%	109,346	75,864	12,028
Nov.	597,346	488,000	82%	109,346	75,864	12,028
Dec.	597,346	488,000	82%	109,346	75,864	12,028
	7,317,274			656,074		

ELECTRICITY GENERATED ANNUALLY BY THE CHP SYSTEM (kWh/year)	7,317,274
ANNUAL SAVINGS ON ELECTRICITY COSTS THANKS TO CHP SYSTEM (€/year)	1,035,550
ANNUAL INCOME FROM SALE OF SURPLUS ELECTRICITY(€/year)	72,168

Table 7: Cost of cogeneration system

Cost of cogeneration system and absorption chiller	1,117,228	€
Operating cost of CHP system	58,538	€/year
Annual fuel costs for CHP system	1,446,101	€/year

Table 8: Cost-benefit table

YEAR	TOTAL COST	BOOK VALUE	INVESTMENT COST	BENEFITS FROM CHP SYSTEM GENERATION	OPERATING COST	DEPRECIATION	BENEFITS MINUS OPERATING COST
0	1,173,090		-1,173,090				
1	0		0	410,348	-58,538	111,723	351,810
2	0		0	410,348	-58,538	111,723	351,810
3	0		0	410,348	-58,538	111,723	351,810
4	0		0	410,348	-58,538	111,723	351,810
5	0		0	410,348	-58,538	111,723	351,810
6	0		0	410,348	-58,538	111,723	351,810
7	0		0	410,348	-58,538	111,723	351,810
8	0		0	410,348	-58,538	111,723	351,810
9	0		0	410,348	-58,538	111,723	351,810
10	0		0	410,348	-58,538	111,723	351,810
11	0		0	410,348	-58,538		351,810
12	0		0	410,348	-58,538		351,810
13	0		0	410,348	-58,538		351,810
14	0		0	410,348	-58,538		351,810
15	0	0.00	0	410,348	-58,538		351,810
	0		0				0
	0		0				0
	0		0				0
	0		0				0
	0		0				0

Table 9: Cash flow table

YEAR	TOTAL INTEREST	BENEFITS FROM CHP SYSTEM GENERATION	OPERATING COST	LOAN INSTALMENTS	DEPRECIATION	TAXES	NET BENEFITS
-3	0			0			
-2	0			0			
-1	0			0			
0	0			0			
1	0	410,348	-58,538	0	111,723	-24,009	327,801
2	0	410,348	-58,538	0	111,723	-24,009	327,801
3	0	410,348	-58,538	0	111,723	-24,009	327,801
4	0	410,348	-58,538	0	111,723	-24,009	327,801
5	0	410,348	-58,538	0	111,723	-24,009	327,801
6	0	410,348	-58,538	0	111,723	-24,009	327,801
7	0	410,348	-58,538	0	111,723	-24,009	327,801
8	0	410,348	-58,538	0	111,723	-24,009	327,801
9	0	410,348	-58,538	0	111,723	-24,009	327,801
10	0	410,348	-58,538	0	111,723	-24,009	327,801
11	0	410,348	-58,538	0		-35,181	316,629
12	0	410,348	-58,538	0		-35,181	316,629
13	0	410,348	-58,538	0		-35,181	316,629
14	0	410,348	-58,538	0		-35,181	316,629
15	0	410,348	-58,538	0		-35,181	316,629
	0			0		0	0
	0			0		0	0
	0			0		0	0
	0			0		0	0
	0			0		0	0

Table 10: Investment viability indicators

NPV	**1,303,863**	**€**
IRR	**27.12%**	
Benefit/Cost	**2.1**	
Discounted payback period (DPB)	**5.00**	**years**

The tables above are based on the optimum technical solution studied.

7. Conclusions

The preliminary viability study conducted indicates that the installation of a cogeneration system in the FOUR SEASONS Hotel is **financially viable**.

The table that follows shows the results of the energy behaviour analysis conducted on the proposed cogeneration system.

Minimum CHP efficiency (•min)	0.75	
Power loss coefficient (•CHP)	0	TJ
Useful heat from cogeneration (qCHP)	39.51	TJ
Total efficiency (electricity + useful heat) (•)	0.80	
CHP efficiency (nCHP) (the greater of • and •min)	0.80	
Non-CHP electrical efficiency (•non-CHP,p)	0.32	
Ratio of electric and/or mechanical energy to heat (•CHP)	0.67	
CHP electric and/or mechanical energy (pCHP)	26.34	TJ
Non-CHP electric and/or mechanical energy (pnon-CHP)	0.000	TJ
Fuel consumption for generation of non-CHP electric and/or mechanical energy (fnon-CHP,p)	0.00	TJ
Fuel consumption for generation of CHP electric and/or mechanical energy (fCHP)	82.32	TJ
CHP electrical efficiency (CHP E•)	0.32	
CHP thermal efficiency (CHP ••)	0.48	
CHP primary energy saving ratio (PESRCHP)	0.21	21%
Check: CHP En + CHP •• = nCHP (CHP En + CHP •• - nCHP=0)	0	
PES	21.298	TJ

5.1.5.2 CENTRAL BANK BUILDING

Energy needs of undertaking

This study pertains to the building of the Central Bank of Cyprus. The bank consumes approximately 3.3 GWh a year mainly for lighting, air conditioning, etc. Electricity consumption increases during the summer months when cooling equipment is used for air conditioning purposes. Part of this cooling load demand can be met by an absorption chiller.

Approximately 120,000 litres of diesel are consumed each year to meet the bank's thermal needs. Seventy-five percent of the fuel is used to heat bank spaces and 25% to heat water.

For the purposes of this study, electricity consumption during the winter months is understood to meet all bank operating needs, except for air conditioning. The additional energy demand in the summer months is due to air conditioners. From an energy perspective, the bank is in operation 365 days a year (security lighting, air-conditioning conditions, etc. even during non-service hours).

Description of cogeneration system

1. System selection

The cogeneration system was selected based on:

- the types of process and the quality of thermal energy required
- the ratio of electricity to heat
- the time distribution of loads
- the fuel available
- the size and cost of the system.

Given the size and type of energy consumption in the undertaking, the cogeneration system selected is the reciprocating internal combustion engine (RICE). The thermal energy generated will be used to meet the bank's thermal needs in the winter months. During the summer months there is surplus thermal energy, which will be used for the cooling equipment operating on an absorption cycle to meet the bank's air conditioning needs.

2. System dimensioning

The system's dimensioning was based on the bank's heat and cooling loads. The installation of a 450 kWe RICE cogeneration system and a 400 kW absorption chiller is being examined. The absorption chiller will be operating in the summer months and will meet approximately 30-50% of load demands. There is no thermal energy surplus in the winter given the higher demand due to the bank's heating requirements. The operation of the system will meet the bank's heat load demands in full and its cooling load demands in part, while 100% of the electricity generated will be used by the bank.

3. Cost of system

The proposed system consists of a reciprocating internal combustion engine, an electric generator and an absorption chiller. The system's estimated total cost is €530,000.

4. Fuel cost and quality

The fuel used will be diesel. Its cost has been assumed as 0.787 €/l.

5. Maintenance and operating costs

The system's maintenance and operating costs are estimated to be approximately €15,000 a year, which includes spare parts and man hours spent on system maintenance work and operation.

6. Numerical results

The study's data and results are shown in detail in the tables that follow:

Table 1: General Financial Data

GENERAL FINANCIAL DATA				
Economic life of investment	15	years		
Desirable rate of return (d)	10%			
Inflators				
Fuel	0%			
Labour and maintenance	0%			
Investor tax rate	10%			
Construction duration	1	years		
Investment cost distribution over construction years				
year -3	0%			
year -2				
year -1	50%			
start 0	50%			
DEPRECIATION			**RATE**	
% of capital	100%	in	10	years
BOOK VALUE				
% of capital	0%			
CAPITAL STRUCTURE				
Subsidies				
year -3	0%	of investment cost		
year -2	0%	of investment cost		
year -1	0%	of investment cost		
Subsidised loans				
year -3	0%	of investment cost		
year -2	0%	of investment cost		
year -1	0%	of investment cost		
Bank loans				

year -3	0%	of investment cost
year -2	0%	of investment cost
year -1	0%	of investment cost

LOAN TERMS
Subsidised

Duration	0	years
Grace period	0	years
Interest	0%	

Bank

Duration	0	years
Grace period	0	years
Interest	0%	

ACCOUNTING PERIOD	15	years

Table 2: Heat and electrical loads of undertaking

DATA - LOADS

Operating hours of undertaking – Heat and electricity needs

Month	Hours of operation	Heat required from fuel • (• J/h)	Heat required from fuel B (• J/h)	Electricity required for cooling (kWh/month)	Total electricity required (kWh/month)
January	450	1,280		0	234,080
February	450	1,280		0	234,080
March	450	1,280		0	234,080
April	450	1,280		0	234,080
May	450	597		86,613	328,100
June	450	597		86,613	328,100
July	450	597		86,613	328,100
August	450	597		86,613	328,100
September	450	597		86,613	328,100
October	450	1,280		0	234,080
November	450	1,280		0	234,080
December	450	1,280		0	234,080
TOTAL	5,400			433,067	3,279,060

Table 3: Data on conventional system

DATA: CONVENTIONAL SYSTEM

	FUEL •		FUEL •	
Fuel	Diesel			
Boiler fuel unit cost	0.79	€/l		€/ • m3
Lower heating value	44.80	• J/l		• J/Nm3
Energy efficiency of conventional system (%)	80%			

Table 4: Data of cogeneration system

Cogeneration technology	Reciprocating internal combustion engine	
Electrical power	450	kWe
Total efficiency	75%	
Electrical efficiency	35%	
Fuel type	Diesel	
Fuel unit cost	0.79	€/l
Lower heating value of fuel	44.80	• J/l
CHP system cost	1,000	€/ kWe
CHP system operating and maintenance cost	8	€/ • Wh
Absorption chiller capacity	400	kW cooling capacity
Absorption chiller cost	200	€/kW cooling capacity
Coefficient of performance (COP) of absorption chiller (%)	70%	
COP of conventional cooling equipment	3	

CHP SYSTEM OPERATION

Month	Load % (Assumption: heat/electricity ratio and efficiency remain constant when load decreases)	Hours of operation (system availability must be taken into account)
January	81%	382.5
February	81%	382.5
March	81%	382.5
April	81%	382.5
May	100%	382.5
June	100%	382.5
July	100%	382.5
August	100%	382.5
September	100%	382.5
October	81%	382.5
November	81%	382.5
December	81%	382.5

Table 5: Calculation of value of thermal energy generated

	Heat generated by CHP system per month (• J)	Thermal energy required exclusively for heat loads per month (• J) (Fuel A)	Thermal energy required exclusively for heat loads per month (• J) (Fuel B)	Thermal energy required for cooling per month (• J)	Maximum thermal energy absorbed by absorption **chiller** per month (MJ) (operation concurrent with CHP system)	Useful thermal energy absorbed by absorption **chiller** per month (MJ) (operation concurrent with CHP system)	Monthly thermal energy surplus after heat load demand (Fuel A) has been met by CHP system (MJ)
Jan.	**576,000**	**576,000**	**0**	0	0	0	0
Feb.	**576,000**	**576,000**	**0**	0	0	0	0
Mar.	**576,000**	**576,000**	**0**	0	0	0	0
Apr.	**576,000**	**576,000**	**0**	0	0	0	0
May	**708,171**	**268,800**	**0**	1,336,320	786,857	786,857	439,371
Jun.	**708,171**	**268,800**	**0**	1,336,320	786,857	786,857	439,371
Jul.	**708,171**	**268,800**	**0**	1,336,320	786,857	786,857	439,371
Aug.	**708,171**	**268,800**	**0**	1,336,320	786,857	786,857	439,371
Sept.	**708,171**	**268,800**	**0**	1,336,320	786,857	786,857	439,371
Oct.	**576,000**	**576,000**	**0**	0	0	0	0
Nov.	**576,000**	**576,000**	**0**	0	0	0	0
Dec.	**576,000**	**576,000**	**0**	0	0	0	0
TOTAL	**7,572,857**	**5,376,000**	**0**	6,681,600	3,934,286	3,934,286	2,196,857
Annual quantity of heat generated by CHP system for heating and cooling	**7,572,857**	**• J/year**					

Monthly thermal energy surplus after heat load demand (Fuel B) has been met by CHP system (MJ)	Monthly thermal energy surplus after heat and cooling load demand (Fuel A) has been met by CHP system (MJ)	Useful thermal energy generated per month by CHP system to meet heat load demand (Fuel A) (MJ)	Useful thermal energy generated per month by CHP system to meet heat load demand (Fuel B) (MJ)	Useful thermal energy generated per month by CHP system to meet cooling load demand (MJ)	Monthly gains from heat load demand (Fuel A) met with CHP system (€)	Monthly gains from heat load demand (Fuel B) met with CHP system (€)	Monthly gains from cooling load demand met with CHP system (€)	Percentage of total heat and cooling load needs met (%)
0	0	576,000	0	0	12,648	0	0	100%
0	0	576,000	0	0	12,648	0	0	100%
0	0	576,000	0	0	12,648	0	0	100%
0	0	576,000	0	0	12,648	0	0	100%
439,371	0	268,800	0	439,371	5,903	0	4,427	44%
439,371	0	268,800	0	439,371	5,903	0	4,427	44%
439,371	0	268,800	0	439,371	5,903	0	4,427	44%
439,371	0	268,800	0	439,371	5,903	0	4,427	44%
439,371	0	268,800	0	439,371	5,903	0	4,427	44%
0	0	576,000	0	0	12,648	0	0	100%
0	0	576,000	0	0	12,648	0	0	100%
0	0	576,000	0	0	12,648	0	0	100%
2,196,857	0	5,376,000	0	2,196,857	118,050	0	22,136	

Table 6: Calculation of value of electricity generated

	Electricity generated by CHP system per month (kWh/month)	Electricity used for own consumption per month (kWh/month)	% of electricity generated by CHP system that is used for own consumption	Electricity sold per month (kWh/month)	Monthly savings on electricity costs thanks to CHP system (€/month)	Monthly income from sale of surplus electricity (€/month)
Jan.	140,000	140,000	100%	0	21,764	0
Feb.	140,000	140,000	100%	0	21,764	0
Mar.	140,000	140,000	100%	0	21,764	0
Apr.	140,000	140,000	100%	0	21,764	0
May	172,125	172,125	100%	0	26,759	0
Jun.	172,125	172,125	100%	0	26,759	0
Jul.	172,125	172,125	100%	0	26,759	0
Aug.	172,125	172,125	100%	0	26,759	0
Sept.	172,125	172,125	100%	0	26,759	0
Oct.	140,000	140,000	100%	0	21,764	0
Nov.	140,000	140,000	100%	0	21,764	0
Dec.	140,000	140,000	100%	0	21,764	0
	1,840,625			0		

ELECTRICITY GENERATED ANNUALLY BY THE CHP SYSTEM (kWh/year)	1,840,625
ANNUAL SAVINGS ON ELECTRICITY COSTS THANKS TO CHP SYSTEM (€/year)	286,144
ANNUAL INCOME FROM SALE OF SURPLUS ELECTRICITY(€/year)	0

Table 7: Cost of cogeneration system

Cost of cogeneration system and absorption chiller	530,000	€
Operating cost of CHP system	14,725	€/year
Annual fuel costs for CHP system	332,580	€/year

Table 8: Cost-benefit table

YEAR	TOTAL COST	BOOK VALUE	INVESTMENT COST	BENEFITS FROM CHP SYSTEM GENERATION	OPERATING COST	DEPRECIATION	BENEFITS MINUS OPERATING COST
0	556,500		-556,500				
1	0		0	93,749	-14,725	53,000	79,024
2	0		0	93,749	-14,725	53,000	79,024
3	0		0	93,749	-14,725	53,000	79,024
4	0		0	93,749	-14,725	53,000	79,024
5	0		0	93,749	-14,725	53,000	79,024
6	0		0	93,749	-14,725	53,000	79,024
7	0		0	93,749	-14,725	53,000	79,024
8	0		0	93,749	-14,725	53,000	79,024
9	0		0	93,749	-14,725	53,000	79,024
10	0		0	93,749	-14,725	53,000	79,024
11	0		0	93,749	-14,725		79,024
12	0		0	93,749	-14,725		79,024
13	0		0	93,749	-14,725		79,024
14	0		0	93,749	-14,725		79,024
15	0	0.00	0	93,749	-14,725		79,024
	0		0				0
	0		0				0
	0		0				0
	0		0				0
	0		0				0

Table 9: Cash flow table

YEAR	TOTAL INTEREST	BENEFITS FROM CHP SYSTEM GENERATION	OPERATING COST	LOAN INSTALMENTS	DEPRECIATION	TAXES	NET BENEFITS
-3	0			0			
-2	0			0			
-1	0			0			
0	0			0			
1	0	93,749	-14,725	0	53,000	-2,602	76,422
2	0	93,749	-14,725	0	53,000	-2,602	76,422
3	0	93,749	-14,725	0	53,000	-2,602	76,422
4	0	93,749	-14,725	0	53,000	-2,602	76,422
5	0	93,749	-14,725	0	53,000	-2,602	76,422
6	0	93,749	-14,725	0	53,000	-2,602	76,422
7	0	93,749	-14,725	0	53,000	-2,602	76,422
8	0	93,749	-14,725	0	53,000	-2,602	76,422
9	0	93,749	-14,725	0	53,000	-2,602	76,422
10	0	93,749	-14,725	0	53,000	-2,602	76,422
11	0	93,749	-14,725	0		-7,902	71,122
12	0	93,749	-14,725	0		-7,902	71,122
13	0	93,749	-14,725	0		-7,902	71,122
14	0	93,749	-14,725	0		-7,902	71,122
15	0	93,749	-14,725	0		-7,902	71,122
	0			0		0	0
	0			0		0	0
	0			0		0	0
	0			0		0	0
	0			0		0	0

Table 10: Investment viability indicators

NPV	**17,023**	**€**
IRR	**10.54%**	
Benefit/Cost	**1.0**	
Discounted payback period (DPB)	**15.00**	**years**

The tables above are based on the optimum technical solution studied.

7. Conclusions

The preliminary viability study conducted indicates that the installation of a cogeneration system at the Central Bank building is not financially viable.
In the event that the investment is granted a 30% subsidy, the financial viability indicators will be as follows, leading us to conclude that the investment is not particularly advantageous.

NPV	**182,153**	**€**
IRR	**17.83%**	
Benefit/Cost	**1.5**	
Discounted payback period (DPB)	**8.00**	**years**

Lastly, the table that follows shows the results of the energy behaviour analysis conducted on the cogeneration system proposed.

Minimum CHP efficiency (•min)	0.75	
Power loss coefficient (•CHP)	0	TJ
Useful heat from cogeneration (qCHP)	7.57	TJ
Total efficiency (electricity + useful heat) (•)	0.75	
CHP efficiency (nCHP) (the greater of • and •min)	0.75	
Non-CHP electrical efficiency (•non-CHP,p)	0.35	
Ratio of electric and/or mechanical energy to heat (•CHP)	0.88	
CHP electric and/or mechanical energy (pCHP)	6.63	TJ
Non-CHP electric and/or mechanical energy (pnon-CHP)	0.000	TJ
Fuel consumption for generation of non-CHP electric and/or mechanical energy (fnon-CHP,p)	0.00	TJ
Fuel consumption for generation of CHP electric and/or mechanical energy (fCHP)	18.93	TJ
CHP electrical efficiency (CHP E•)	0.35	
CHP thermal efficiency (CHP ••)	0.40	
CHP primary energy savings ratio (PESRCHP)	0.19	19%
Check: CHP En + CHP •• = nCHP (CHP En + CHP •• - nCHP=0)	0	
PES	4.467	TJ

5.1.2.3 LIMASSOL GENERAL HOSPITAL

Energy needs of undertaking

This study pertains to Limassol General Hospital. The hospital consumes approximately 11.8 GWh annually, mainly for lighting, air conditioning, elevators, etc. Electricity consumption increases during the summer months when cooling equipment is used.

Thermal energy is mainly used for heating hospital interior spaces, for producing hot service water (10 t/day at 75˚C) and for generating steam (1 t/h, 160˚C, 9 bar – 250 days/year). Approximately 870,000 litres of diesel are consumed each year to meet hospital thermal needs.

The following have been taken into consideration for this study:

- The additional energy demand in the summer months is due to air conditioners.
- Thermal power demand in the summer months is considered to be the base heat load that remains constant throughout the year, while the additional demand during the winter season meets space heating needs.

The hospital is in operation 24 hours a day, 365 days a year.

Description of cogeneration system

1. System selection

The cogeneration system was selected on the basis of:

- the types of process and the quality of thermal energy required
- the ratio of electricity to heat
- the time distribution of loads
- the fuel available
- the size and cost of the system.

Given the size and type of energy consumption in the undertaking, the cogeneration system selected is the reciprocating internal combustion engine (RICE). The thermal energy generated will be used to meet the hospital's thermal needs in the winter months. During the summer months there is surplus thermal energy, which will be used for cooling equipment operating on an absorption cycle to meet the hospital's air conditioning needs.

2. System dimensioning

The system's dimensioning was based on the hospital's heat and cooling loads. The installation of a 1300 kWe RICE cogeneration system and a 926 kW absorption chiller is being examined. The absorption chiller will be operating in the summer months using the surplus thermal energy. There is no thermal energy surplus in the winter given the higher demand due to hospital heating requirements. The operation of the system will meet the hospital's heat load demands in full and 50% of its cooling load demands, while 90-100% of the electricity generated will be used by the hospital.

3. Cost of system

The proposed system consists of a recipr•cating internal combustion engine, an electric generator and an absorption chiller. The system's estimated total cost is 1.5 million euros.

4. Fuel cost and quality

The fuel used will be diesel. Its estimated cost is 0.787 €/l.

5. Maintenance and operating costs

The system's maintenance and operating costs are estimated to be approximately €77,000 a year and include spare parts and man hours spent on system maintenance work and operation.

6. Numerical results

The study's data and results are shown in detail in the tables that follow:

Table 1: General Financial Data

GENERAL FINANCIAL DATA				
Economic life of investment	15	years		
Desirable rate of return (d)	10%			
Inflators				
Fuel	0%			
Labour and maintenance	0%			
Investor tax rate	10%			
Construction duration	1	years		
Investment cost distribution over construction years				
year -3	0%			
year -2				
year -1	50%			
start 0	50%			
DEPRECIATION			**RATE**	
% of capital	100%	in	10	years
BOOK VALUE				
% of capital	0%			
CAPITAL STRUCTURE				
Subsidies				
year -3	0%	of investment cost		
year -2	0%	of investment cost		
year -1	0%	of investment cost		
Subsidised loans				
year -3	0%	of investment cost		
year -2	0%	of investment cost		
year -1	0%	of investment cost		
Bank loans				
year -3	0%	of investment cost		
year -2	0%	of investment cost		
year -1	0%	of investment cost		
LOAN TERMS				
Subsidised				
Duration	0	years		
Grace period	0	years		
Interest	0%			
Bank				
Duration	0	years		
Grace period	0	years		
Interest	0%			
ACCOUNTING PERIOD	15	years		

Table 2: Heat and electrical loads of undertaking

DATA - LOADS

Operating hours of undertaking – Heat and electricity needs

Month	Hours of operation	Heat required from fuel • (• J/h)	Heat required from fuel B (• J/h)	Electricity required for cooling (kWh/month)	Total electricity required (kWh/month)
January	732	5,916		0	732,000
February	732	5,916		0	732,000
March	732	5,916		0	732,000
April	732	2,958		376,509	1,229,150
May	732	2,958		376,509	1,229,150
June	732	2,958		376,509	1,229,150
July	732	2,958		376,509	1,229,150
August	732	2,958		376,509	1,229,150
September	732	2,958		376,509	1,229,150
October	732	5,916		0	732,000
November	732	5,916		0	732,000
December	732	5,916		0	732,000
TOTAL	8,784			2,259,056	11,766,900

Table 3: Data on conventional system

DATA: CONVENTIONAL SYSTEM

	FUEL A		FUEL B	
Fuel	Diesel			
Boiler fuel unit cost	0.79	€/l		€/ • m3
Lower heating value	44.80	• J/l		• J/Nm3
Energy efficiency of conventional system (%)	80%			

Table 4: Data on cogeneration system

Cogeneration technology	Reciprocating internal combustion engine	
Electrical power	1,300	kWe
Total efficiency	80%	
Electrical efficiency	32%	
Fuel type	Diesel	
Fuel unit cost	0.79	€/l
Lower heating value of fuel	44.80	• J/l
CHP system cost	1,000	€/kWe
CHP system operating and maintenance cost	8	€/ • Wh
Absorption chiller capacity	926	kW cooling capacity
Absorption chiller cost	200	€/kW cooling capacity
Coefficient of performance (COP) of absorption chiller (%)	70%	
COP of conventional cooling equipment	3	

CHP SYSTEM OPERATION

Month	Load % (Assumption: heat/electricity ratio and efficiency remain constant when load decreases)	Hours of operation (system availability must be taken into account)
January	99%	622.2
February	99%	622.2
March	99%	622.2
April	100%	622.2
May	100%	622.2
June	100%	622.2
July	100%	622.2
August	100%	622.2
September	100%	622.2
October	99%	622.2
November	99%	622.2
December	99%	622.2

Table 5: Calculation of value of generated thermal energy

	Heat generated by CHP system per month (• J)	**Thermal energy required exclusively for heat loads per month (• J) (Fuel A)**	**Thermal energy required exclusively for heat loads per month (• J) (Fuel B)**	Thermal energy required for cooling per month (• J)	Maximum thermal energy absorbed by absorption chiller per month (MJ) (operation concurrent with CHP system)	Useful thermal energy absorbed by absorption chiller per month (MJ) (operation concurrent with CHP system)	Monthly thermal energy surplus after heat load demand (Fuel A) has been met by CHP system (MJ)
Jan.	**4,324,166**	**4,330,667**	**0**	0	0	0	0
Feb.	**4,324,166**	**4,330,667**	**0**	0	0	0	0
Mar.	**4,324,166**	**4,330,667**	**0**	0	0	0	0
Apr.	**4,367,844**	**2,165,333**	**0**	5,809,001	2,962,591	2,962,591	2,202,511
May	**4,367,844**	**2,165,333**	**0**	5,809,001	2,962,591	2,962,591	2,202,511
Jun.	**4,367,844**	**2,165,333**	**0**	5,809,001	2,962,591	2,962,591	2,202,511
Jul.	**4,367,844**	**2,165,333**	**0**	5,809,001	2,962,591	2,962,591	2,202,511
Aug.	**4,367,844**	**2,165,333**	**0**	5,809,001	2,962,591	2,962,591	2,202,511
Sept.	**4,367,844**	**2,165,333**	**0**	5,809,001	2,962,591	2,962,591	2,202,511
Oct.	**4,324,166**	**4,330,667**	**0**	0	0	0	0
Nov.	**4,324,166**	**4,330,667**	**0**	0	0	0	0
Dec.	**4,324,166**	**4,330,667**	**0**	0	0	0	0
TOTAL	**52,152,057**	**38,976,000**	**0**	34,854,008	17,775,544	17,775,544	13,215,064
Annual quantity of heat generated by CHP system for heating and cooling	**52,152,057**	**• J/year**					

Monthly thermal energy surplus after heat load demand (Fuel B) has been met by CHP system (MJ)	Monthly thermal energy surplus after heat and cooling load demand (Fuel A) has been met by CHP system (MJ)	Useful thermal energy generated per month by CHP system to meet heat load demand (Fuel A) (MJ)	Useful thermal energy generated per month by CHP system to meet heat load demand (Fuel B) (MJ)	Useful thermal energy generated per month by CHP system to meet cooling load demand (MJ)	Monthly gains from heat load demand (Fuel A) met with CHP system (€)	Monthly gains from heat load demand (Fuel B) met with CHP system (€)	Monthly gains from cooling load demand met with CHP system (€)	Percentage of total heat and cooling load needs met (%)
0	0	4,324,166	0	0	94,953	0	0	100%
0	0	4,324,166	0	0	94,953	0	0	100%
0	0	4,324,166	0	0	94,953	0	0	100%
2,202,511	0	2,165,333	0	2,202,511	47,548	0	22,193	55%
2,202,511	0	2,165,333	0	2,202,511	47,548	0	22,193	55%
2,202,511	0	2,165,333	0	2,202,511	47,548	0	22,193	55%
2,202,511	0	2,165,333	0	2,202,511	47,548	0	22,193	55%
2,202,511	0	2,165,333	0	2,202,511	47,548	0	22,193	55%
2,202,511	0	2,165,333	0	2,202,511	47,548	0	22,193	55%
0	0	4,324,166	0	0	94,953	0	0	100%
0	0	4,324,166	0	0	94,953	0	0	100%
0	0	4,324,166	0	0	94,953	0	0	100%
13,215,064	0	38,936,993	0	13,215,064	855,006	0	133,156	

Table 6: Calculation of value of electricity generated

	Electricity generated by CHP system per month (kWh/month)	Electricity used for own consumption per month (kWh/month)	% of electricity generated by CHP system that is used for own consumption	Electricity sold per month (kWh/month)	Monthly savings on electricity costs thanks to CHP system (€/month)	Monthly income from sale of surplus electricity (€/month)
Jan.	800,771	732,000	91%	68,771	113,797	7,565
Feb.	800,771	732,000	91%	68,771	113,797	7,565
Mar.	800,771	732,000	91%	68,771	113,797	7,565
Apr.	808,860	808,860	100%	0	125,745	0
May	808,860	808,860	100%	0	125,745	0
Jun.	808,860	808,860	100%	0	125,745	0
Jul.	808,860	808,860	100%	0	125,745	0
Aug.	808,860	808,860	100%	0	125,745	0
Sept.	808,860	808,860	100%	0	125,745	0
Oct.	800,771	732,000	91%	68,771	113,797	7,565
Nov.	800,771	732,000	91%	68,771	113,797	7,565
Dec.	800,771	732,000	91%	68,771	113,797	7,565
	9,657,788			412,628		

ELECTRICITY GENERATED ANNUALLY BY THE CHP SYSTEM (kWh/year)	9,657,788
ANNUAL SAVINGS ON ELECTRICITY COSTS THANKS TO CHP SYSTEM (€/year)	1,437,253
ANNUAL INCOME FROM SALE OF SURPLUS ELECTRICITY(€/year)	45,389

Table 7: Cost of cogeneration system

Cost of cogeneration system and absorption chiller	1,485,169	€
Operating cost of CHP system	77,262	€/year
Annual fuel costs for CHP system	1,908,653	€/year

Table 8: Cost-benefit table

YEAR	TOTAL COST	BOOK VALUE	INVESTMENT COST	BENEFITS FROM CHP SYSTEM GENERATION	OPERATING COST	DEPRECIATION	BENEFITS MINUS OPERATING COST
0	1,559,427		-1,559,427				
1	0		0	562,151	-77,262	148,517	484,889
2	0		0	562,151	-77,262	148,517	484,889
3	0		0	562,151	-77,262	148,517	484,889
4	0		0	562,151	-77,262	148,517	484,889
5	0		0	562,151	-77,262	148,517	484,889
6	0		0	562,151	-77,262	148,517	484,889
7	0		0	562,151	-77,262	148,517	484,889
8	0		0	562,151	-77,262	148,517	484,889
9	0		0	562,151	-77,262	148,517	484,889
10	0		0	562,151	-77,262	148,517	484,889
11	0		0	562,151	-77,262		484,889
12	0		0	562,151	-77,262		484,889
13	0		0	562,151	-77,262		484,889
14	0		0	562,151	-77,262		484,889
15	0	0.00	0	562,151	-77,262		484,889
	0		0				0
	0		0				0
	0		0				0
	0		0				0
	0		0				0

Table 9: Cash flow table

YEAR	TOTAL INTEREST	BENEFITS FROM CHP SYSTEM GENERATION	OPERATING COST	LOAN INSTALMENTS	DEPRECIATION	TAXES	NET BENEFITS
-3	0			0			
-2	0			0			
-1	0			0			
0	0			0			
1	0	562,151	-77,262	0	148,517	-33,637	451,252
2	0	562,151	-77,262	0	148,517	-33,637	451,252
3	0	562,151	-77,262	0	148,517	-33,637	451,252
4	0	562,151	-77,262	0	148,517	-33,637	451,252
5	0	562,151	-77,262	0	148,517	-33,637	451,252
6	0	562,151	-77,262	0	148,517	-33,637	451,252
7	0	562,151	-77,262	0	148,517	-33,637	451,252
8	0	562,151	-77,262	0	148,517	-33,637	451,252
9	0	562,151	-77,262	0	148,517	-33,637	451,252
10	0	562,151	-77,262	0	148,517	-33,637	451,252
11	0	562,151	-77,262	0		-48,489	436,400
12	0	562,151	-77,262	0		-48,489	436,400
13	0	562,151	-77,262	0		-48,489	436,400
14	0	562,151	-77,262	0		-48,489	436,400
15	0	562,151	-77,262	0		-48,489	436,400
	0			0		0	0
	0			0		0	0
	0			0		0	0
	0			0		0	0
	0			0		0	0

Table 10: Investment viability indicators

NPV	**1,851,124**	**€**
IRR	**28.18%**	
Benefit/Cost	**2.2**	
Discounted payback period (DPB)	**5.00**	**years**

The tables above are based on the optimum technical solution studied.

7. Conclusions

The preliminary viability study conducted indicates that the installation of a cogeneration system at Limassol General Hospital is **financially viable**.

Lastly, the table that follows shows the results of the energy behaviour analysis conducted on the cogeneration system proposed.

Minimum CHP efficiency (•min)	0.75	
Power loss coefficient (•CHP)	0	TJ
Useful heat from cogeneration (qCHP)	52.15	TJ
Total efficiency (electricity + useful heat) (•)	0.80	
CHP efficiency (nCHP) (the greater of • and •min)	0.80	
Non-CHP electrical efficiency (•non-CHP,p)	0.32	
Ratio of electrical and/or mechanical energy to heat (•CHP)	0.67	
CHP electrical and/or mechanical energy (pCHP)	34.77	TJ
Non-CHP electrical and/or mechanical energy (pnon-CHP)	0.000	TJ
Fuel consumption for generation of non-CHP electrical and/or mechanical energy (fnon-CHP,p)	0.00	TJ
Fuel consumption for generation of CHP electrical and/or mechanical energy (fCHP)	108.65	TJ
CHP electrical efficiency (CHP E•)	0.32	
CHP thermal efficiency (CHP ••)	0.48	
CHP primary energy savings ratio (PESRCHP)	0.21	21%
Check: CHP En + CHP •• = nCHP (CHP En + CHP •• - nCHP=0)	0	
PES	28.111	TJ

5.1.2.4 LEDRA BRICK FACTORY LTD

Energy needs of undertaking

This study pertains to LEDRA Brick Factory Ltd. The factory is connected to the EAC's grid at medium voltage and it is charged according to schedule of rates No. 73. It consumes approximately 3.2 GWh a year. Its average monthly electricity consumption reaches 275,000 kWh, at a corresponding monthly cost of approximately €36,000.

The factory's thermal processes require hot air for the kilns (at temperatures of 160–180^{0}C) and dryers (at temperatures of 75–80^{0}C) on a twenty-four hour basis. Factory thermal needs are met by consuming 1,650 tons of HFO and 950 tons of LFO each year.

The factory is in operation 24 hours a day, 6 days a week.

Daily, weekly and monthly load distribution is stable. It is assumed that the factory operates 12 months a year, although it was understood from the information provided in the questionnaire that August is the maintenance period.

Description of cogeneration system

1. System selection

The cogeneration system was selected on the basis of:

- the types of process and the quality of thermal energy required
- the ratio of electricity to heat
- the time distribution of loads
- the fuel available
- the size and cost of the system.

Given the size and type of energy consumption in the undertaking, the cogeneration system selected is the extraction condensing steam turbine. The thermal energy generated will be used to meet in full the factory's thermal needs as well as its air conditioning needs using an absorption chiller.

2. System dimensioning

The system's dimensioning was based on the factory's heat loads. The installation of a 2MWe HFO-fired extraction condensing steam turbine cogeneration system and an approximately 31 kWc absorption chiller is being examined. The operation of the system will meet the factory's heat and cooling load demands, while 23% of the electricity generated will be used by the factory and the surplus sold to the EAC.

3. Cost of system

The system proposed consists of an extraction condensing steam turbine, an electric generator and an absorption chiller. The system's estimated total cost is 2.4 million euros.

4. Fuel cost and quality

The fuel used will be HFO. Its cost has been set at 0.316 €/kg.

5. Maintenance and operating costs

The system's maintenance and operating costs are estimated at approximately €85,000 a year and include spare parts and man hours spent on system maintenance work and operation.

6. Numerical results

The study's data and results are shown in detail in the tables that follow:

Table 1: General Financial Data

GENERAL FINANCIAL DATA					
Economic life of investment	15	years			
Desirable rate of return (d)	10%				
Inflators					
Fuel	0%				
Labour and maintenance	0%				
Investor tax rate	10%				
Construction duration	1	years			
Investment cost distribution over construction years					
year -3	0%				
year -2					
year -1	50%				
start 0	50%				
DEPRECIATION				**RATE**	
% of capital	100%		in	10	years
BOOK VALUE					
% of capital	0%				
CAPITAL STRUCTURE					
Subsidies					
year -3	0%	of investment cost			
year -2	0%	of investment cost			
year -1	0%	of investment cost			
Subsidised loans					
year -3	0%	of investment cost			
year -2	0%	of investment cost			
year -1	0%	of investment cost			
Bank loans					
year -3	0%	of investment cost			
year -2	0%	of investment cost			
year -1	0%	of investment cost			
LOAN TERMS					
Subsidised					
Duration	0	years			
Grace period	0	years			
Interest	0%				
Bank					
Duration	0	years			
Grace period	0	years			
Interest	0%				
ACCOUNTING PERIOD	15	years			

Table 2: Heat and electrical loads of undertaking

DATA - LOADS

Operating hours of undertaking – Heat and electricity needs

Month	Hours of operation	Heat required from fuel • (• J/h)	Heat required from fuel B (• J/h)	Electricity required for cooling (kWh/month)	Total electricity required (kWh/month)
January	636	9,243	5,552	0	274,988
February	636	9,243	5,552	0	274,988
March	636	9,243	5,552	0	274,988
April	636	9,243	5,552	0	274,988
May	636	9,243	5,552	5,627	274,988
June	636	9,243	5,552	5,627	274,988
July	636	9,243	5,552	5,627	274,988
August	636	9,243	5,552	5,627	274,988
September	636	9,243	5,552	0	274,988
October	636	9,243	5,552	0	274,988
November	636	9,243	5,552	0	274,988
December	636	9,243	5,552	0	274,988
TOTAL	7.632			22,508	3,299,850

Table 3: Data on conventional system

DATA: CONVENTIONAL SYSTEM

	FUEL A		FUEL B	
Fuel	HFO		LFO	
Boiler fuel unit cost	0.32	€/kg	0.45	€/kg
Lower heating value	43.12	• J/kg	44.00	• J/kg
Energy efficiency of conventional system (%)	80%		80%	

Table 4: Data on cogeneration system

Cogeneration technology	Extraction condensing steam turbine	
Electrical power	2,000	kWe
Total efficiency	80%	
Electrical efficiency	25%	
Fuel type	HFO	
Fuel unit cost	0.32	€/kg
Lower heating value of fuel	43.12	• J/kg
CHP system cost	1,200	€/kWe
CHP system operating and maintenance cost	6	€/ • Wh
Absorption chiller capacity	31	kW cooling capacity
Absorption chiller cost	200	€/kW cooling capacity
Coefficient of performance (COP) of absorption chiller (%)	70%	
COP of conventional cooling equipment	3	

CHP SYSTEM OPERATION

Month	Load % (Assumption: heat/electricity ratio and efficiency remain constant when load decreases)	Hours of operation (system availability must be taken into account)
January	98%	604.2
February	98%	604.2
March	98%	604.2
April	98%	604.2
May	99%	604.2
June	99%	604.2
July	99%	604.2
August	99%	604.2
September	98%	604.2
October	98%	604.2
November	98%	604.2
December	98%	604.2

Table 5: Value of generated thermal energy

	Heat generated by CHP system per month (• J)	**Thermal energy required exclusively for heat loads per month (• J) (Fuel A)**	**Thermal energy required exclusively for heat loads per month (• J) (Fuel B)**	Thermal energy required for cooling per month (• J)	Maximum thermal energy absorbed by absorption **chiller** per month (MJ) (operation concurrent with CHP system)	Useful thermal energy absorbed by absorption **chiller** per month (MJ) (operation concurrent with CHP system)	Monthly thermal energy surplus after heat load demand (Fuel A) has been met by CHP system (MJ)
Jan.	**9,409,693**	**5,878,693**	**3,531,000**	0	0	0	3,531,000
Feb.	**9,409,693**	**5,878,693**	**3,531,000**	0	0	0	3,531,000
Mar.	**9,409,693**	**5,878,693**	**3,531,000**	0	0	0	3,531,000
Apr.	**9,409,693**	**5,878,693**	**3,531,000**	0	0	0	3,531,000
May	**9,474,823**	**5,878,693**	**3,531,000**	86,816	97,137	86,816	3,596,129
Jun.	**9,474,823**	**5,878,693**	**3,531,000**	86,816	97,137	86,816	3,596,129
Jul.	**9,474,823**	**5,878,693**	**3,531,000**	86,816	97,137	86,816	3,596,129
Aug.	**9,474,823**	**5,878,693**	**3,531,000**	86,816	97,137	86,816	3,596,129
Sept.	**9,409,693**	**5,878,693**	**3,531,000**	0	0	0	3,531,000
Oct.	**9,409,693**	**5,878,693**	**3,531,000**	0	0	0	3,531,000
Nov.	**9,409,693**	**5,878,693**	**3,531,000**	0	0	0	3,531,000
Dec.	**9,409,693**	**5,878,693**	**3,531,000**	0	0	0	3,531,000
TOTAL	**113,176,838**	**70,544,320**	**42,372,000**	347,264	388,550	347,264	42,632,518
Annual quantity of heat generated by CHP system for heating and cooling	**113,176,838**	**• J/year**					

Monthly thermal energy surplus after heat load demand (Fuel B) has been met by CHP system (MJ)	Monthly thermal energy surplus after heat and cooling load demand (Fuel A) has been met by CHP system (MJ)	Useful thermal energy generated per month by CHP system to meet heat load demand (Fuel A) (MJ)	Useful thermal energy generated per month by CHP system to meet heat load demand (Fuel B) (MJ)	Useful thermal energy generated per month by CHP system to meet cooling load demand (MJ)	Monthly gains from heat load demand (Fuel A) met with CHP system (€)	Monthly gains from heat load demand (Fuel B) met with CHP system (€)	Monthly gains from cooling load demand met with CHP system (€)	Percentage of total heat and cooling load needs met (%)
0	0	5,878,693	3,531,000	0	53,714	45,224	0	100%
0	0	5,878,693	3,531,000	0	53,714	45,224	0	100%
0	0	5,878,693	3,531,000	0	53,714	45,224	0	100%
0	0	5,878,693	3,531,000	0	53,714	45,224	0	100%
65,129	0	5,878,693	3,531,000	65,129	53,714	45,224	566	100%
65,129	0	5,878,693	3,531,000	65,129	53,714	45,224	566	100%
65,129	0	5,878,693	3,531,000	65,129	53,714	45,224	566	100%
65,129	0	5,878,693	3,531,000	65,129	53,714	45,224	566	100%
0	0	5,878,693	3,531,000	0	53,714	45,224	0	100%
0	0	5,878,693	3,531,000	0	53,714	45,224	0	100%
0	0	5,878,693	3,531,000	0	53,714	45,224	0	100%
0	0	5,878,693	3,531,000	0	53,714	45,224	0	100%
260,518	0	70,544,320	42,372,000	260,518	644,564	542,687	2,263	

Table 6: Calculation of Value of electricity generated

	Electricity generated by CHP system per month (kWh/month)	Electricity used for own consumption per month (kWh/month)	% of electricity generated by CHP system that is used for own consumption	Electricity sold per month (kWh/month)	Monthly savings on electricity costs thanks to CHP system (€/month)	Monthly income from sale of surplus electricity (€/month)
Jan.	1,188,093	274,988	23%	913,105	36,859	100,442
Feb.	1,188,093	274,988	23%	913,105	36,859	100,442
Mar.	1,188,093	274,988	23%	913,105	36,859	100,442
Apr.	1,188,093	274,988	23%	913,105	36,859	100,442
May	1,196,316	274,988	23%	921,329	36,859	101,346
Jun.	1,196,316	274,988	23%	921,329	36,859	101,346
Jul.	1,196,316	274,988	23%	921,329	36,859	101,346
Aug.	1,196,316	274,988	23%	921,329	36,859	101,346
Sept.	1,188,093	274,988	23%	913,105	36,859	100,442
Oct.	1,188,093	274,988	23%	913,105	36,859	100,442
Nov.	1,188,093	274,988	23%	913,105	36,859	100,442
Dec.	1,188,093	274,988	23%	913,105	36,859	100,442
	14,290,005			10,990,155		

ELECTRICITY GENERATED ANNUALLY BY THE CHP SYSTEM (kWh/year)	14,290,005
ANNUAL SAVINGS ON ELECTRICITY COSTS THANKS TO CHP SYSTEM (€/year)	442,312
ANNUAL INCOME FROM SALE OF SURPLUS ELECTRICITY(€/year)	1,208,917

Table 7: Cost of cogeneration system

Cost of cogeneration system and absorption chiller	2,406,252	€
Operating cost of CHP system	85,740	€/year
Annual fuel costs for CHP system	1,504,141	€/year

Table 8: Cost-benefit table

YEAR	TOTAL COST	BOOK VALUE	INVESTMENT COST	BENEFITS FROM CHP SYSTEM GENERATION	OPERATING COST	DEPRECIATION	BENEFITS MINUS OPERATING COST
0	2,526,565		-2,526,565				
1	0		0	1,336,601	-85,740	240,625	1,250,861
2	0		0	1,336,601	-85,740	240,625	1,250,861
3	0		0	1,336,601	-85,740	240,625	1,250,861
4	0		0	1,336,601	-85,740	240,625	1,250,861
5	0		0	1,336,601	-85,740	240,625	1,250,861
6	0		0	1,336,601	-85,740	240,625	1,250,861
7	0		0	1,336,601	-85,740	240,625	1,250,861
8	0		0	1,336,601	-85,740	240,625	1,250,861
9	0		0	1,336,601	-85,740	240,625	1,250,861
10	0		0	1,336,601	-85,740	240,625	1,250,861
11	0		0	1,336,601	-85,740		1,250,861
12	0		0	1,336,601	-85,740		1,250,861
13	0		0	1,336,601	-85,740		1,250,861
14	0		0	1,336,601	-85,740		1,250,861
15	0	0.00	0	1,336,601	-85,740		1,250,861
	0		0				0
	0		0				0
	0		0				0
	0		0				0
	0		0				0

Table 9: Cash flow table

YEAR	TOTAL INTEREST	BENEFITS FROM CHP SYSTEM GENERATION	OPERATING COST	LOAN INSTALMENTS	DEPRECIATION	TAXES	NET BENEFITS
-3	0			0			
-2	0			0			
-1	0			0			
0	0			0			
1	0	1,336,601	-85,740	0	240,625	-101,024	1,149,838
2	0	1,336,601	-85,740	0	240,625	-101,024	1,149,838
3	0	1,336,601	-85,740	0	240,625	-101,024	1,149,838
4	0	1,336,601	-85,740	0	240,625	-101,024	1,149,838
5	0	1,336,601	-85,740	0	240,625	-101,024	1,149,838
6	0	1,336,601	-85,740	0	240,625	-101,024	1,149,838
7	0	1,336,601	-85,740	0	240,625	-101,024	1,149,838
8	0	1,336,601	-85,740	0	240,625	-101,024	1,149,838
9	0	1,336,601	-85,740	0	240,625	-101,024	1,149,838
10	0	1,336,601	-85,740	0	240,625	-101,024	1,149,838
11	0	1,336,601	-85,740	0		-125,086	1,125,775
12	0	1,336,601	-85,740	0		-125,086	1,125,775
13	0	1,336,601	-85,740	0		-125,086	1,125,775
14	0	1,336,601	-85,740	0		-125,086	1,125,775
15	0	1,336,601	-85,740	0		-125,086	1,125,775
	0			0		0	0
	0			0		0	0
	0			0		0	0
	0			0		0	0
	0			0		0	0

Table 10: Investment viability indicators

NPV	**6,184,025**	**€**
IRR	**45.32%**	
Benefit/Cost	**3.4**	
Discounted payback period (DPB)	**3.00**	**years**

The tables above are based on the optimum solution in terms of technical potential.

7. Conclusions

The preliminary viability study conducted indicates that the installation of a cogeneration system at LEDRA Brick Factory is **financially viable**. Lastly, the table that follows shows the results of the energy behaviour analysis conducted on the cogeneration system proposed.

Minimum CHP efficiency (•min)	0.80	
Power loss coefficient (•CHP)	0	TJ
Useful heat from cogeneration (qCHP)	113.18	TJ
Total efficiency (electricity + useful heat) (•)	0.80	
CHP efficiency (nCHP) (the greater of • and •min)	0.80	
Non-CHP electrical efficiency (•non-CHP,p)	0.25	
Ratio of electric and/or mechanical energy to heat (•CHP)	0.45	
CHP electric and/or mechanical energy (pCHP)	51.44	TJ
Non-CHP electric and/or mechanical energy (pnon-CHP)	0.000	TJ
Fuel consumption for generation of non-CHP electric and/or mechanical energy (fnon-CHP,p)	0.00	TJ
Fuel consumption for generation of CHP electric and/or mechanical energy (fCHP)	205.78	TJ
CHP electrical efficiency (CHP E•)	0.25	
CHP thermal efficiency (CHP ••)	0.55	
CHP primary energy savings ratio (PESRCHP)	0.15	15%
Check: CHP En + CHP •• = nCHP (CHP En + CHP •• - nCHP=0)	0	
PES	36.973	TJ

5.2 Economic Potential for CHP near Power Stations

5.2.1 Study on District Heating and District Cooling provided for the city of Limassol by Moni Power Station

a. General

Insufficient data have been obtained for the quantification of heat and cooling load needs. Calculations will, therefore, be based on assumptions described in detail in the study and on experience gained from the development of similar systems in Greece and other countries.

Heat and cooling load data have been obtained on five (5) hotels in Limassol, while no such data are available on the wider Larnaca area.

More specifically, for Limassol, there are data on the annual heat and cooling loads of the following hotels: ALASIA, ATLANTICA BAY, LOUIS APOLLONIA BEACH, LE MERIDIEN SPA & RESORT and ST. RAPHAEL. The last two hotels are among the largest in the city.

These hotel units' total heat load (for hot water and heating) amounts to **66.015 x 10^6 MJ/year** and their cooling load to **19.490 x 10^6 MJ/year** (=5.414 x 10^6 kWh/year). Their annual heat load, mainly due to demand for hot service water, is, thus, 3.3 times higher than their cooling load.

For the purposes of this study, the relevant needs of all hotel units in Limassol that may be met by a district heating and cooling system are estimated in practice to be **three times** the loads above. Estimates are also provided on the household sector heat load for densely inhabited parts of the city where district heating may be an option. Certain assumptions have been made to this effect and are provided in a paragraph below. There are no prospects for district cooling in the household sector.

b. Heat capacity of system

The capacity required by the hotel units under study is determined as follows:

Hotel sector heating/hot water system heat capacity

Boilers at hotels are usually used to produce hot water, whereas in the household sector this need is expected to be met mainly using solar systems.

Capacity is determined on the basis of the length of time the system is in operation to produce hot water, given that this need exists throughout a hotel's operating period.

The following assumptions have been made:

- The hotel operating period is 10 months a year, 30 days a month.
- The hot water production system operates at full load 12 hours a day.

Thus, the running hours of the hot water production system (equivalent full load hours) are:

10 months/year x 30 days/month x 12 hours/day = 3,600 hours/year

For the running hours above, the heat capacity of the hotel units in Limassol area is:

(198,047,002 MJ/year) / (3.6 x 3,600 hours/year) = **15,281 kWth**

Hotel sector cooling system capacity

The following assumption has been made as regards the operating method of air conditioning systems (equivalent full load hours):

- May, in operation for 15 days, 4 hours/day,
- June, in operation for 30 days, 8 hours/day
- July, in operation for 30 days, 14 hours/day
- August, in operation for 30 days, 14 hours/day
- September, in operation for 25 days, 8 hours/day
- October, in operation for 15 days, 4 hours/day

Consequently, annual running hours are:

15 x 4 + 30 x 8 + (30 x 14) x 2 + 25 x 8 + 15 x 4 = 1,400 hours/year

The cooling capacity corresponding to the running hours above is:

(56,470,583 MJ/year) / (3.6 x 1,400 hours/year) = 11,601 **kWcool**

Given that the COP for absorption chillers using hot water at temperatures of 115-120^{o}C is approximately 0.9, the heat capacity required to meet the cooling load demand above is **12,890 kWth**.

A condensing unit in a cooling facility running on electricity has a COP of at least 2.5. Consequently, for preference to be given to absorption units, their thermal energy (kWh-th) costs must be at most ¼ of their electric energy (kWh-e) costs. Given also that such cooling equipment (absorption units) is much more expensive than conventional systems, district cooling will not be evaluated any further before obtaining more precise data on relevant loads.

Household sector heating/hot water system heat capacity

The following assumptions have been made so as to determine the heat capacity required:

- Mean surface area of building: 120 m^2/residence; mean building height: 3.2 m
- Heat loss from building: 25 kcal/m^3
- Building population: 5 people/residence
- Total population of city section being studied: 5,000 individuals

Based on the above, the heat loss load is:

(5000/5) residences x (120x3.2)m^3/residence x 25 kcal/m^3 x 1.163 = **11,165 kWth.**

With a 20% increment added so that hot service water may also be included, the total heat capacity of the household sector is estimated to be:

11,165 x 1.2 = **13,398 kWth.**

In order to determine the system's annual running hours, the following operating assumptions have been made (equivalent full load hours):

- November, in operation for 15 days, 4 hours/day
- December, in operation for 30 days, 6 hours/day
- January, in operation for 30 days, 8 hours/day
- February, in operation for 30 days, 6 hours/day
- March, in operation for 15 days, 4 hours/day

Consequently, the running hours are:

(15 x 5) x 2 + (30 x 8) x 2 + 30 x 10 + = 930 hours/year

And the thermal energy required on an annual basis is:

13.398 x 930 x 3.6 = **44.856 x 10^6 MJ/year**

Based on the above, **24,563 kWth** in heat capacity and an annual thermal energy of **242.633 x 10^6 MJ/year** will be required to meet the total heat load needs for the household and hotel sectors.

For the purposes of the economic evaluation, the district heating project shall be assumed to have a total heat load of **30 MWth** and an annual thermal energy supply of **296.340 x 10^6 MJ/year** (= 242.633 x 30/24.563).

c. System costs

- **Cost of district heating system**

Such an installation usually comprises the steam and condensate lines, the water/steam heat exchangers, the condensate pumps and the district heating water section.

The estimated supply and installation cost of such a system is **€2,600,000.**

- **Cost of heat transmission system**

This cost comprises the main transmission (feed and return) lines, and the pumping station needed to distribute the water.

The hot water supply required for transmission line dimensioning must first be determined, assuming a water-feed temperature of 120°C and return temperature of 70°C, as follows:

30,000 kWth / { (120 – 70)°C x 4.2 kJ/kg °C} = 142.86 kg/s = 0.148 m^3/s

Therefore, assuming a fluid velocity of 3 m/s along the main transmission lines, the resulting cross-section would:

sqrt { (0.148 m^3/s / 3 m/s) x 4 / • } = 250.66 mm = 9.87 in.

Insulated 10-inch pipes are selected, at an estimated supply cost of €70/m and installation cost of €25/m.

For an estimated total length equal to 25 km of feed and return lines, the cost amounts to **€2,375,000.**

The following equation is used to calculate capacity required for the pumping station (in kW):

Pp = 22.49 x q x l x •

Where:

q (m^3/s) is water supply, equal to 0.148m^3/s

l (m) is total length, equal to 25,000 m

• (mmH_2O/m) is the drop in pressure adjusted to pipe length, estimated to be 0.003

Based on the above the total capacity is estimated at 249.7 kW. Consequently, for every thermal MWh transmitted, <u>8.32 kWh</u> in pipe consumption is needed.

Given 3 pumps (3 x 50%) at a specific cost of 600 €/kW, the relevant cost is estimated to be:

3 x (249.7 kW / 2) x 600 €/kW = **€224,700.**

- **Cost of heat distribution system**

The distribution system comprises all primary, secondary and tertiary pipes comprising the distribution network to reach all consumers (hotel units, blocks of flats, large detached houses). The water/water heat exchanger, the cost of which is usually borne by the consumer, has not been included in the system's cost.

For this cost to be estimated, the layout of the network must first be estimated, which is particularly difficult at this stage. Based on the experience gained from similar projects, this cost is 1.5 to 3.5 times the cost of the transmission lines, depending on the transmission distance and on the total capacity of the plant. For the purposes of this study, the cost of the heat distribution system is assumed to be 2.5 times this cost, that is:

2.5 x €2,375,000 = **€5,937,500.**

- **Total investment cost**

Based on the above, the total investment cost is:

5,937.5 + 224.7 + 2,375 + 2,600 = **€11,137,200.**

This investment cost does not include an oil-fired boiler room (with an approximate capacity of 10 MWth), which may have to be installed in the district heating system as a backup and in order to meet peak load demands that cannot be met by the thermal energy provided by the power plants.

- **Annual operating cost of district heating system**

This cost comprises the operating cost of the pumping station and the maintenance cost of the entire system.

<u>Maintenance cost</u>

This is estimated to be 2.5% of the annual investment cost, i.e.

2.5% x €9,949,700 = **248.7 k€/year**

Operating cost

The thermal energy transmitted annually by the system is estimated to be:

296.340 x10^6 / 3,600 = 82,317 MWh/year

Consequently, the electricity consumed to operate the system is:

82,317 MWh-th x 8.32 kWh-el/MWh-th = 683,228 kWh-el

Assuming an electricity cost of 0.07 €/kWh-el, the system's annual operating cost would be:

683,228 x 0.07 = **47.825 k€/year**

Note that the operating cost of the power plant's condensate pumps will most likely be included in the selling cost of thermal energy.

Based on the above, the annual operating cost of the district heating system amounts to:

248.7 + 47.825 = **296.53 k€/year**

- **Total annual cost of district heating system**

Based on the above, the total annual operating and maintenance cost (excluding depreciations) comes to:

296,530.0 €/year

This results in the following annual cost of generated thermal energy:

296,530. 0€/year / 82,317 MWh-th = **3.60 €/MWh-th**.

This cost does not yet include the cost of purchasing the thermal energy from the EAC. Assuming that the EAC's pricing policy on the thermal energy supplied would be to recover the money lost from the corresponding drop in electricity sales, and also assuming that the average selling price of electricity at household rates is approximately 0.15 €/kWh-el, the resultant purchasing cost of thermal energy would be:

(3.4 MWel/14 MWth) x 0.17* €/kWh-el = 41.28 €/MWh-th

* The price was set slightly higher than the selling price of electricity so as to incorporate a likely fixed charge.

Based on the above, the annual cost of the district heating system, including the purchasing cost of thermal energy, amounts to:

- 44.88 €/ • Wh-th, without taking into consideration the annual depreciation cost,

or on an annual basis:

- 3,694,386.9 €/year, without taking into consideration the annual depreciation cost.

- **Economic evaluation of investment**

Note that to generate 1MWh-th of thermal energy using a conventional boiler that is 83% efficient and which uses light fuel oil costing 1.09 €/year, the fuel alone will cost 112.56 €/ • Wh-th.

We can, therefore, conclude that any thermal energy selling price that does not exceed 80% of the energy generation cost above will be considered as worthwhile for the consumer to invest the required small sum in order to get connected to the district heating network.

a) Non-subsidised project

Given the data above, the net present value (NPV) of the investment over 20 years at an 8% interest rate is presented in the table below.

Thermal Energy Selling Price €/MWh-th	Discounted Payback Period Years	NPV over 20 years
50.00	>20	€-6,999,213.0
60.00	16.35	€1,082,792.2
70.00	7.33	€9,164,795.6
80.00	4.78	€17,246,800.0
90.00	3.56	€25,328,804.4

These data indicate that the investment is **worthwhile** even without being subsidised. Therefore, more extensive and accurate research needs to be conducted on district heating for the city of Limassol.

5.2.2 Study on District Heating and District Cooling provided for the city of Larnaca and Agia Napa area by Dekeleia Power Station

a. General

There are almost no data available for the quantification of heat and cooling load needs in the hotel and household sectors.

However, given that Dekeleia plants are able to provide a high heat load (twice that of Moni plants) and also given the fact that Dekeleia is situated near the tourist area of Larnaca and is not very far from the tourist area of Agia Napa, district heating is expected to be an interesting prospect in the case of Dekeleia Power Station, too. More specifically, its estimated distance from Larnaca is 10-15 km, and from Agia Napa, 35-40 km.

Based on the above, there could be a common hot water generation system and two distinct heat load distribution networks for Larnaca and Agia Napa areas.

Calculations have been based on assumptions described in detail in the study and on experience gained from the development of similar systems in Greece and other countries.

For the purposes of this study, relevant heating and cooling needs of all hotel units in Larnaca that are on the same side as Dekeleia Power Station and can be served by a district heating and cooling system are estimated in practice to represent **85%** of Limassol's needs, i.e. 168,339,952 MJ/year in thermal energy and 47,999,996 MJ/year in cooling energy.

The same heat and cooling loads are believed to apply to Agia Napa area as well. Heat and cooling load demand in these areas is expected to be simultaneous.

Estimates have only been provided on the household sector heat load of Larnaca, and this only for densely inhabited parts of the city where district heating may be an option. Certain assumptions have been made to this effect and are provided in a paragraph below. There are no prospects for district cooling in the household sector.

b. Heat capacity of the system

The required capacity of hotel units under study is determined as follows:

<u>Hotel sector heating/hot water system heat capacity</u>

Boilers at hotels are usually used to produce hot water, whereas in the household sector this need is expected to be met mainly using solar systems.

Capacity is determined on the basis of the length of time the system is in operation to produce hot water, given that this need exists throughout a hotel's operating period.

The following assumptions have been made:

- The hotel operating period is 10 months a year, 30 days a month.
- The hot water production system operates at full load 12 hours a day.

Thus, the running hours of the hot water production system (equivalent full load hours) are:

10 months/year x 30 days/month x 12 hours/day = 3,600 hours/year

For these running hours, the heat capacity of hotel units in the city of Larnaca is:

(168,339,952 MJ/year) / (3.6 x 3,600 hours/year) = **12,989 kWth**

An equivalent heat capacity is also believed to be needed for Agia Napa area.

<u>Hotel sector cooling system capacity</u>

The following assumption has been made as regards the operating method of air conditioning systems (equivalent full load hours):

- May, in operation for 15 days, 4 hours/day,
- June, in operation for 30 days, 8 hours/day
- July, in operation for 30 days, 14 hours/day
- August, in operation for 30 days, 14 hours/day
- September, in operation for 25 days, 8 hours/day
- October, in operation for 15 days, 4 hours/day

Consequently, the annual running hours are:

15 x 4 + 30 x 8 + (30 x 14) x 2 + 25 x 8 + 15 x 4 = 1,400 hours/year

The cooling capacity corresponding to these running hours is:

(56,470,583 MJ/year) / (3.6 x 1,400 hours/year) = **9,524 kWcool**

Given that the COP for absorption chillers using hot water at temperatures of 115-120^{o}C is approximately 0.9, the heat capacity required to meet the above cooling load demand is **10,582 kWth**.

District cooling will not be evaluated any further for the reasons provided in an earlier paragraph.

<u>*Household sector heating/hot water system heat capacity*</u>

The following assumptions have been made so as to determine the heat capacity required:

- Mean surface area of building: 120 m^2/residence; mean building height: 3.2 m
- Heat loss from building: 25 kcal/m^3
- Building population: 5 people/residence
- Total population of city section being studied: 5,000 individuals

Based on the above, the heat loss load is:

(5000 / 5) residences x (120 x 3.2)m^3/residence x 25 kcal/m^3 x 1.163 = **11,165 kWth.**

With a 20% increment added so that hot service water may also be included, the total heat capacity of the household sector is estimated to be:

11,165 x 1.2 = **13,398 kWth.**

In order to determine the system's annual running hours, the following operating assumptions have been made (equivalent full load hours):

- November, in operation for 15 days, 4 hours/day
- December, in operation for 30 days, 6 hours/day
- January, in operation for 30 days, 8 hours/day
- February, in operation for 30 days, 6 hours/day
- March, in operation for 15 days, 4 hours/day

Consequently, the running hours are:

(15 x 5) x 2 + (30 x 8) x 2 + 30 x 10 + = 930 hours/year

And the thermal energy required on an annual basis is:

13.398 x 930 x 3.6 = **44.856 x 10^6 MJ/year**

Based on the above, **39,376 kWth** in heat capacity and an annual thermal energy of **381,535,904 MJ/year** would be required to meet the overall heat load needs for the household and hotel sectors.

For the purposes of the economic evaluation, the district heating project shall be assumed to have a total heat load of **45 MWth** and an annual thermal energy supply of **436,029,959 MJ/year** (= 381,535,904 x 45/39.376). Of this heat capacity, 15 MWth is estimated to be for Agia Napa area and the rest for Larnaca.

c. System costs

- **<u>Cost of district heating system</u>**

Such an installation usually comprises the steam and condensate lines, the water/steam heat exchangers, the condensate pumps and the district heating water section.

The total supply and installation cost estimated for such a system is **€3,500,000**, of which €2,350,000 applies to Larnaca and €1,150,000 to Agia Napa.

- **<u>Cost of heat transmission system</u>**

This cost comprises the main transmission (feed and return) lines, and the pumping station needed to distribute the water.

The hot water supply required for transmission line dimensioning must first be determined, assuming a water-feed temperature of 120˚C and return temperature of 70^{o}C, as follows:

a) <u>Transmission to Larnaca</u>

30,000 kWth / { (120 – 70)^{o}C x 4.2 kJ/kg ^{o}C} = 142.86 kg/s = 0.148 m^3/s

Assuming, then, that the fluid velocity is 3 m/s along the main transmission lines, the resulting cross-section would be:

sqrt { (0.148 m^3/s / 3 m/s) x 4 / • } = 250.66 mm = 9.87 in.

Insulated 10-inch pipes are selected, at an estimated supply cost of €70/m and an installation cost of €25/m.

For an estimated total length of 25 km of feed and return lines, the corresponding cost amounts to **€2,375,000.**

The following equation is used to calculate the capacity required for the pumping station (in kW):

Pp = 22.49 x q x l x •

Where:

q (m^3/s) is water supply, equal to 0.148m^3/s

l (m) is total length, equal to 25,000 m

• (mmH_2O/m) is the drop in pressure adjusted to pipe length, estimated to be 0.003

Based on the above the total capacity is estimated at 249.7 kW. Consequently, for every thermal MWh transmitted, <u>8.32 kWh</u> in pipe consumption is needed.

Given 3 pumps (3 x 50%) at a specificl cost of 600 €/kW, the relevant cost is estimated to be:

3 x (249.7 kW / 2) x 600 €/kW = **€224,700.**

b) <u>Transmission to Agia Napa</u>

15,000 kWth / {(120 – 70)^{o}C x 4.2 kJ/kg ^{o}C} = 71.43 kg/s = 0.074m^3/s

Therefore, assuming a fluid velocity of 3 m/s along the main transmission lines, the resulting cross-section would be:

sqrt { (0.074 m^3/s / 3 m/s) x 4 / • } = 177.22 mm = 6.98 in.

Insulated 7-inch pipes are selected, at an estimated supply cost of €50/m and an installation cost of €20/m.

For an estimated total length of 75 km of feed and return lines, the corresponding cost amounts to **€5,250,000.**

The following equation is used to calculate the pumping station's required capacity (in kW):

Pp = 22.49 x q x l x •

Where:

q (m^3/s) is water supply, equal to 0.074 m^3/s

l (m) is total length, equal to 75,000 m

• (mmH_2O/m) is the drop in pressure adjusted to pipe length, estimated to be 0.003

Based on the above the total capacity is estimated at 374.5 kW. Consequently, for every thermal MWh transmitted, 25.97 kWh in pipe consumption is needed.

Given 3 pumps (3 x 50%) at a special cost of 600 €/kW, the relevant cost is estimated to be:

3 x (374.5 kW / 2) x 600 €/kW = **€337,000.**

- **Cost of heat distribution system**

The distribution system comprises all primary, secondary and tertiary pipes comprising the distribution network to reach all consumers (hotel units, blocks of flats, large detached houses). The water/water heat exchanger, the cost of which is usually borne by the consumer, has not been included in the cost of the system.

For this cost to be estimated, the layout of the network must first be assessed, which is particularly difficult at this stage. Based on the experience gained from similar projects, this cost is 1.5 to 3.5 times the cost of the transmission lines, depending on the transmission distance and on the total capacity of the plant. For the purposes of this study, the cost of the heat distribution system is assumed to be 2.5 times this cost for Larnaca area and 1.5 times for Agia Napa area. The resultant distribution costs are therefore:

a) for Larnaca area

2.5 x €2,375,000 = **€5,937,500**

b) for Agia Napa area

1.5 x €5,250,000 = **€7,875,000**

- **Total investment cost**

Based on the above, the total investment cost is:

a) for Larnaca area

5,937.5 + 224.7 + 2,375 + 2,350 = **€10,887,200**

b) for Agia Napa area

7,875 + 337 + 5,250 + 1,150 = **€14,612,000**

The above investment cost does not include an oil-fired boiler room (of an approximate capacity of 10 MWth for the Larnaca system and 5 MWth for the Agia Napa system), which may have to be installed in the district heating system as a backup and in order to meet peak load demands that cannot be met by the thermal energy provided by the power plants.

- **Annual operating cost of district heating system**

This cost comprises the operating cost of the pumping station and the maintenance cost of the entire system.

Maintenance cost

This is estimated to be 2.5% of the annual investment cost, i.e.

a) for Larnaca system

2.5% x €10,887,200 = **272.2 k€/year**

b) for Agia Napa system

2.5% x €14,612,000 = **365.3 k€/year**

Pump operating cost

a) for Larnaca system

The thermal energy transmitted annually by the system is estimated to be:

290.6866393 $x10^6$ / 3,600 = 80,746.3 MWh/year

Consequently, the electricity consumed to operate the system is:

80,746.3 MWh-th x 8.32 kWh-el/MWh-th = 671,809,1 kWh-el

Assuming an electricity cost of 0.07 €/kWh-el, the system's annual operating cost would come to:

671,809.1 x 0.07 = **47.026 k€/year**

Note that the operating cost of the power plant's condensate pumps will most likely be included in the selling cost of thermal energy.

b) for Agia Napa system

Thermal energy transmitted annually by the system is estimated to be:

145.343196 x 10^6 / 3,600 = 40,373.1 MWh/year

Consequently, the electricity consumed to operate the system is:

40,373,1MWh-th x 25.97 kWh-el/MWh-th = 1,049,489.7 kWh-el

Assuming an electricity cost of 0.07 €/kWh-el, the system's annual operating cost would come to:

1,049,489.7 x 0.07 = **73.394 k€/year**

<u>Annual operating cost of system</u>

Based on the above, the district heating system's annual operating cost (including maintenance and electricity for pumps only) amounts to:

a) for Larnaca system

272.2 + 47.026 = **319.226 k€/year**

b) for Agia Napa system

365.3 + 73.394 = **438.694 k€/year**

- <u>**Total annual cost of district heating system**</u>

Based on the above, the total annual operating and maintenance cost (excluding depreciation) is:

a) for Larnaca system

319,226.0 €/year

This results in the following annual cost of thermal energy generated:

319,226.0 €/year / 80,746.3 MWh-th = **3.95 €/MWh-th**

This cost does not yet include the cost of purchasing the thermal energy from the EAC. Assuming that all EAC stations will have the same selling price for thermal energy, the cost will, once again, be equal to 41.28 €/MWh-th.

Based on the above, the annual cost of the district heating system, including the purchasing cost of thermal energy, amounts to:

- 45.23 €/ • Wh-th, without taking into consideration the annual depreciation cost,

or on an annual basis:

- 3,652,155.1 €/year, without taking into consideration the annual depreciation cost,

b) for Agia Napa system

438,694.0 €/year

This results in the following annual cost of generated thermal energy:

438,694.0 €/year / 40,373.1 MWh-th = **10.86 €/MWh**.

Based on the above, the annual cost of the district heating system, including the purchasing cost of thermal energy, amounts to:

- 52.14 €/ • Wh-th, without taking into consideration the annual depreciation cost,

or on an annual basis:

- 2,105,053.4 €/year, without taking into consideration the annual depreciation cost,

- **Economic evaluation of investment**

a) for Larnaca system

Given the data above, the net present value (NPV) of the non-subsidised investment over 20 years at an 8% interest rate is presented in the table below.

Thermal Energy Selling Price €/MWh-th	Discounted Payback Period Years	NPV over 20 years
50.00	>20	€-7,105,643.3
60.00	17.05	€822,147.4
70.00	7.43	€8,749,938.2
80.00	4.83	€16,677,728.9
90.00	3.58	€24,605,519.7

These data indicate that the investment is **worthwhile** even without being subsidised. Therefore, more extensive and accurate research needs to be conducted on district heating for the city of Larnaca.

b) for Agia Napa system

Given the data above, the net present value (NPV) of the non-subsidised investment over 20 years at an 8% interest rate is presented in the table below.

Thermal Energy Selling Price €/MWh-th	Discounted Payback Period Years	NPV over 20 years
60.00	>20	€-11,496,381.7
70.00	>20	€-7,532,491.3
80.00	>20	€-3,568,600.8
90.00	18.82	€395,289.6

The initial impression is that district heating for Agia Napa area is **not a worthwhile** investment without any subsidisation, mainly due to the long transmission distance and the relatively small heat load. The investment could perhaps become more attractive were the heat load to increase significantly, given that Dekeleia Power Station has a substantial thermal energy potential for district heating.

Note: With a 30% subsidy, the net present value over a 20-year period is zero when the selling price for thermal energy is 77.94 €/MWh-th.

5.3 Biomass CHP Plants

5.3.1 CHP plants burning solid biomass

Community - Location	Power (• We)	Power (• Wth)	Biomass (TJ)
Kalo Horio	3.74	8.22	235.68
Agios Athanasios Municipality	1.79	3.93	112.62
Sinaoros	1.84	4.05	117.02
Lakatamia Municipality	2.15	4.73	180.98
Palaiometoho	1.79	3.93	112.62

5.3.2 Biogas Plants

	Athienou	Aradippou	Orounta
CH_4 Production	1,984,000 m^3/year	3,648,000 m^3/year	(2) 3,648,000 m^3/year
CH_4 Energy Content (9.94kWh/m^3)	19,720,960 kWh/year	36,261,120 kWh/year	(2) 36,261,120 kWh/year
Plant Capacity	2251 kW	4,139 kW	(2) 4,139 kW
Electricity Generation*	7,213 • Wh	13,263 • Wh	(2) 13,263 • Wh
Heat Generation**	8,677 • Wh	15,955 • Wh	(2) 15,955 • Wh

5.4 Economic Potential for CHP in the Household Sector

5.4.1 Assessment of CHP Potential in Detached Houses

A. Introduction

The prospect of implementing a small heating/cooling and electricity cogeneration system in order to meet all or part of such needs in detached houses in Cyprus shall be investigated in this study from a technical and economic perspective.

More specifically, this system is expected to operate during periods when there is a demand for thermal or cooling energy, at which times it will be functioning as a cogeneration system with a high total efficiency rate (over 80%). For this to occur, cooling load demands must be met using thermal rather than electric energy (conventional air conditioning units), in other words, using absorption chillers to convert thermal energy to cooling energy. In addition, the cogeneration unit must be in operation for as many hours as possible so that the cost of the system may be recovered. It is not advisable to operate the cogeneration unit only for electricity generation purposes, as its estimated operating cost is particularly high – higher than the cost of purchasing electricity from the grid.

Given that for such cogeneration systems thermal efficiency is usually “significantly” higher than electrical efficiency, the system’s operating load should be based on heating needs. Any surplus electricity resulting from this operating method will be supplied to the grid.

A cogeneration system is expected to put an end to electric energy supply for meeting electricity needs and cooling/heating needs – when these are met using air conditioning units – and to the consumption of light fuel oil used in hot water heating boilers.

B. Calculation Parameters

The absence of detailed data makes it impossible to precisely determine the heat, cooling and electrical loads required. Furthermore, it is unclear how the necessary heat load demands are met (whether using hot-water boilers or air conditioning units) and also what percentage of electricity consumption corresponds to cooling load demands (operation of air conditioning units).

The figures to be used in relevant calculations are mentioned in this paragraph and have been obtained:

- from available statistics
- through assumptions based on relevant experience or data from Greece, while also taking into consideration the climatic and other characteristics peculiar to Cyprus (higher temperatures both in the winter and in the summer).

Thermal and cooling capacity required is estimated by means of heating and cooling degree days based on the coldest and hottest month, respectively. More specifically, heating is expected to be required when external temperatures drop below the equilibrium temperature of 18^{o}C. Similarly, cooling (air conditioning) is expected to be required when external temperatures rise above 22$^{\bullet}$C. <u>Maximum peak load, whether heat or cooling, is derived from the coldest and hottest day, respectively, and it is directly linked to the running hours of heating and air conditioning systems</u>.

For the purposes of this study the absorption chiller’s COP is assumed to be 1.3, which is a typical value for absorption chillers running on hot water at a temperature of 95^{o}C. The absorption chiller’s cold output is, therefore, 1.3 times the heat input from the cogeneration system. Note that the typical COP value for conventional technology chillers is 3.0.

Calculations are based on a typical detached house in Cyprus, given ‘mean’ environmental data obtained from the weighted averages of values corresponding to the areas of Nicosia, Larnaca (including Famagusta area), Limassol and Paphos (weighting coefficients: 0.35, 0.28, 0.23 and 0.14, respectively).

The following information has been taken into account in these calculations:

a) size of standard detached house: 209 m^2 (1991–2006 average; source: Statistical Service of the Republic of Cyprus),

b) fuel: light fuel oil of a lower heating value of 42,000 kJ/kg

for calculating the installation's heat load

c) total annual heating degree days: 791.5, at an equilibrium temperature of 18^{o}C,

d) total heating degree days during the coldest month (February): 182.6 (at the same equilibrium temperature),

e) minimum temperature during coldest month: 1.9^{o}C, based on data obtained from the Meteorological Service of Cyprus,

f) hours the heating system is in operation each day: 5,

g) months the heating system is in operation each year: 5 (November to March)

h) specific annual heating energy consumption for heating: 55 kWh/m^2/year (given the absence of relevant data and the fact that heat insulation for buildings is most likely not yet compulsory, the value above is based on relevant experience gained in Greece (zone A, 'medium' insulation))

i) ratio of hot-water heat load to heating: 0.1

for calculating the installation's cooling load

j) total annual cooling degree days: 572, at an equilibrium temperature of 22^{o}C

k) total cooling degree days during the hottest month (July): 166.7 (at the same equilibrium temperature),

l) hours the air conditioning system is in operation each day: 9,

m) months the air conditioning system is in operation each year: 6 (May to October)

n) specific annual cooling energy consumption for air conditioning: 20% higher than specific heating energy consumption, in kWh/m^2/year (in Greece, in Zone A areas, the cooling load is approximately equal to the heat load)

o) required absorption chiller heat capacity equal to cooling capacity output.

for calculating the installation's electrical load

p) specific electric energy equal to 28.7 kWh/m^2/year (this value does not include electricity consumed to meet heat and cooling load demands and it is based on data specific to the months of October and November, which is a period without particularly high cooling and heat loads (source: Statistical Service of the Republic of Cyprus) – this value is also typical for a modern residence in Zone A in Greece).

Resultant loads for detached houses, based on the information above, are provided below:

1) Electrical Load

- Total annual electric energy (excluding air conditioners): 6,067.78 kWh
- Peak electrical capacity (4 hours/day): 3.50 kWel
- Average electrical capacity for the rest of the period: 0.50 kWel

2) Heat Load

- Annual thermal energy for heating: 11,500.27 kWh
- Annual thermal energy for hot water: 1,150.03 kWh

- Total annual thermal energy: 12,650.30 kWh
- Peak heat capacity (coldest day): 39.02 kWth
- Average annual heat capacity: 12.78 kWth

3) Cooling Load

- Annual cooling energy: 13,800.32 kWh
- Peak cooling capacity (hottest day): 42.35 kWc
- Average annual cooling capacity: 8.52 kWc

C. Cogeneration system dimensioning

A complete cogeneration system is required, using the equipment necessary to generate electricity and thermal/cooling energy. More specifically, in the case under investigation, the power generation technology needed is a light fuel oil-fired internal combustion engine and a boiler that will recover heat from the engine's cylinder liners and exhaust gases in order to produce hot water. There must also be an indirect-fired absorption chiller that will use hot water from the cogeneration unit, as well as a standby hot-water boiler (provided it has not already been included in the basic equipment of the cogeneration system) if the criterion for dimensioning the cogeneration system is meeting electrical load needs, as described below.

The dimensioning of the household cogeneration unit can be based on one of the following criteria:

i. meeting the house's required heat load in full, with the design heat load being equal to the highest value between the heat load for heating and that for operating the absorption chiller.

ii. Meeting the required electrical load in full and any heat load that may occur.

Note that for a typical detached house, the heat load (for heating and cooling) is expected to be "significantly" higher than the electrical load. Consequently, with design criterion (i) above, the operation of the cogeneration system is expected to yield surplus energy which can be supplied to the grid. In contrast, with design criterion (ii) above, the operation of the cogeneration system is expected to result in a substantial shortage of thermal energy, which must be made up for using a backup conventional boiler.

The above make it obvious that a household's total electricity and thermal/cooling energy needs can be met with design criterion **(i)**. However, the cogeneration unit required in this case is expected to be substantially larger than the system selected under design criterion (ii) and, therefore, entails a higher investment cost.

C.1 CHP system designed to meet heat load demands

In this case, the cogeneration unit must be in operation in both winter and summer in order to meet the household's heat and cooling load demands required. The cogeneration system's operation can take one of the following forms:

- **a)** interrupted operation at full load for a specific number of hours a day (peak load dimensioning). In this case, the cogeneration system's running hours will be significantly fewer than the customary running hours of the heating and air conditioning systems (that is, approximately 2.0 hours instead of 6 and 1.6 hours instead of 9, respectively).
- **b)** "continuous" operation at partial or full load.

In case **a)** (interrupted operation), the electricity required to meet the detached house's needs during periods of cogeneration system inactivity will be supplied by the grid. The household's high electrical loads (e.g. cooker, iron, washing machine, etc.) should, therefore, be planned for times when the cogeneration system will be running so as to minimise the electricity "absorbed" from the grid as much as possible. In this case, the cogeneration system is expected to be big and costly, for a comparatively small number of running hours per year.

In contrast, in case **b)** (continuous operation) the cogeneration system can be dimensioned with respect to the peak heat load and can run mainly at partial load, only running at full heat load during expected peak hours (minimum or maximum environmental temperatures) (scenario **b1)**). The unit will be the same size and will cost the same as in case a) above, but will have many more running hours during which the system can be taken advantage of. Whatever the operational mode (partial or full load), the household's electrical load is expected to be met in full and surplus electricity will once again be supplied to the grid. Note that if the expected partial load is much lower than the system's nominal load, this will significantly reduce the efficiency of the CHP unit, which must be taken into consideration.

Alternatively, for continuous operation, the cogeneration system can be dimensioned in order to meet the 'base' heat load (scenario **b2)**). Any additional thermal or cooling energy required to meet the corresponding peak needs will be supplied by means of a backup hot-water boiler running on light fuel oil and conventional air conditioning units. In this case, the cogeneration system is expected to be relatively small and inexpensive, and to be able to run continuously during periods when heating or cooling (air conditioning) may be required throughout the year.

C.1.1 CHP system designed for peak heat load

The basic features of a household CHP unit running <u>at full load</u> are shown in the table below.

Power output	kWe	24.26
Surplus power	kWe	20.76
Heat output (maximum)	kWth	32.58
Cold output (maximum)	kWc	42.35
Fuel heat input	kWth	69.31
Fuel consumption (light fuel oil)	kg/h	5.94
Electrical efficiency	%	35.0
Thermal efficiency	%	47.0
CHP efficiency	%	82.0

Table 1: Basic Features of CHP Unit

During winter, the CHP unit's maximum required heat output is 39.02 kWth. In this case, the unit will be running at 92% partial load.

The cogeneration system's hours of operation at the maximum thermal and cooling capacity required during the corresponding periods of time (winter and summer) are shown in the table below. This mode of operation is believed to meet the annual thermal and cooling energy demands in full, while also generating significantly higher power during the short operating period than the average power required.

Total running hours (scenario **a)**)	hours/year	594.4
- for heating	hours/year	304.7
- for cooling	hours/year	289.7

Moreover, for the system to be in "continuous" operation (e.g. 16 hours/day), it must run at a very low load, thereby significantly reducing the efficiency of the CHP unit.

A CHP system of this size does not merit further economic evaluation, irrespective of the running hours and mode, given that the investment cost is exceptionally high and cannot be borne by an average household. The investment cost for such a system is estimated to exceed €45,000.

C.1.2 CHP system designed for base heat load

The CHP system's design 'base heat load' is based on the system being in operation 'continuously' throughout the daily running period of the heating and cooling systems, namely 6 hours/day in winter and 9 hours/day in summer.

In this case, the design load, which will also be the full load of the CHP unit, is assumed to be the average annual heat capacity to meet the annual heat load demands, except for the coldest month, and the annual cooling load demands, except for the hottest month, given the above running hours.

Therefore, capacities would be as follows:

- Winter period
  (9,766.82 kWh/year) / {4 months x 30 days x 6 hours} = 13.57 kWth
- Summer period
  (9,778.04 kWh/year) / {5 months x 30 days x 9 hours} = 7.24 kWc
  (7.24 kWc) / 1.3 = 5.57 kWth

More specifically, the heat capacity of the cogeneration system could be the smaller of the two (5.57kWth).

At times in summer when the cooling capacity required to meet a detached house's cooling load is higher than the power generated by the CHP system, use must be made of air conditioners running on electricity. The right size of CHP unit should, therefore, be found, so that enough electricity is generated to cover the electricity required to run the air conditioners, which, together with the CHP system, will meet the cooling load demands of an average day during the hottest month (14.42 kW). Any additional power demand will be met by the grid.

The CHP unit resulting from the above will have a heat capacity of 7.05 kWth. In this case, there is the following surplus electrical power:

	generated:	5.25 kWel
-	consumed (excluding air conditioners):	3.50 kWel
-	surplus (for use by air conditioners):	1.75 kWel

The cooling load resulting from the cooling systems (conventional air conditioners and absorption chiller) is as follows:

- conventional air conditioning units
  (1.75 kWel) x (3.0 kWc/kWel) = 5.25 kWc
- absorption chiller
  (7.05 kWth) x (1.3 kWc/kWth) = 9.17 kWc

Therefore, the total cooling load demand that can be met is:

9.17 kWth (by the CHP unit) + 5.25 kWth (by the air conditioners) = 14.42 kWth

At times in winter, when the heating capacity required to meet a detached house's heat load is higher than the power generated by the CHP system, use must be made of a conventional backup hot-water boiler running on light fuel oil. The boiler's useful heat load must be high enough so that, when operating together with the CHP system, the household's peak heat load can be met (39.02 kWth).

The boiler's maximum heat capacity will, therefore, be:

(39.02 kWth) – (7.05 kWth) = 31.97 kWth

and its efficiency ratio at average operating load equal to 83%.

The cogeneration system resulting from the above information has the following technical features at full load:

Power output	kWel	5.25
Heat output (maximum)	kWth	7.05
Cold output (maximum)	kWc	9.17
Fuel heat input	kW	15.00
Fuel consumption (light fuel oil)	kg/h	1.28
Electrical efficiency	%	35.0
Thermal efficiency	%	47.0
CHP efficiency	%	52.0
Total running hours (scenario **b2)**)	hours/year	2,520.0

Table 2: Basic Features of CHP Unit

In winter the CHP unit above will be operating for a total of 900 hours at an average heat capacity of 7.05 kWth (full load), generating a total of 6,345.0 kWh-th in thermal energy, while in the summer it will be operating for 1350 hours at an average heat capacity of 5.57 kWh (79% load, with 80% efficiency, assuming a 2% drop) and for a period of 270 hours at an average heat capacity of 7.05 kWth (full load), generating a total of 9,423 kWh-c in cooling energy.

For the CHP system to operate in the manner described above, the following is the expected annual fuel consumption:

- Winter period: (900 h) x (1.28 kg/h) = 1,024.0 kg
- Summer period: (1350 h) x (1.28 kg/h) x (79%) x (0.82)/(0.80) = 1,399.2 kg
  (270 h) x (1.28 kg/h) = 345.6 kg

  2,768.8 kg

Similarly, the backup boiler will provide the rest of the thermal energy required by the detached house, its resultant annual useful heat being equal to:

(12,650.3 kWh-th) - (6,345.0 kWh-th) = 6,305.3 kWh-th/year

In order to generate the thermal energy above, the backup boiler will consume the following quantity of fuel:

(6,305.3 kWh/year) x 3600 / {83% x (42,000.0 kJ/kg)} = 651.1 kg

Moreover, the electricity demands of a detached house can be met in full when the above CHP system is in operation, except for some odd moments during summer, when electricity will have to be "absorbed" from the grid in order to meet peak cooling load demands. The home's peak electrical load is expected to occur during the period when the CHP system is in operation; during times when the CHP system is inoperative, electricity will be obtained from the grid at an average capacity of 0.5 kWel.

During the summer period, excluding the hottest month (1350 hours), when the electricity generated will be used in its entirety to run the air conditioners, the CHP system will have an average power output of:

{(5.57 kW) / 46 %*} x 34%* = 4.12 kWel,

(*) Electrical and thermal efficiency has been reduced by 1% in this load.

Therefore resulting in a surplus:

a) for peak electricity hours (4 hours/day)

- electrical capacity: (4.12 kWel) – (3.5 kWel) = 0.62 kWel
- electric energy: (0.62 kWel) x (600 h) = 372.00 kWh

b) for the CHP system's remaining running hours

- electrical capacity: (4.12kWel) – (0.50kWel) = 3.62 kWel
- electric energy: (3.62kWel) x (750h) = 2,747.58 kWh

During the winter period (900 hours), the CHP system's average power output will be 5.25 kWel (full load) at all times, therefore resulting in a surplus:

a) for peak electricity hours (4 hours/day)

- electrical capacity: (5.25kWel) – (3.5kWel) = 1.75 kWel
- electric energy: (1.75kWel) x (600h) = 1,050.00 kWh

b) for the CHP system's remaining running hours

- electrical capacity: (5.25kWel) – (0.50kWel) = 4.75 kWel
- electric energy: (4.75kWel) x (300h) = 1,425.00 kWh

Consequently, assuming the running time expected for the cogeneration system above, the resultant electricity surplus would be equal to 5,594.58 kWh-el/year, which can be sold to the grid. (OKAY)

C.2 CHP system designed to meet electrical load demands

In such a case, the CHP system is chosen so that it may meet peak electricity demands during the period when air conditioners are not in operation, namely 3.5 kWel. The unit will be running at full load throughout the heating and cooling periods, and the surplus electricity generated during non-peak hours will be supplied to the grid.

The basic features of such a CHP unit, running at full load, are shown in the table below.

Power output	kWel	3.50
Heat output (maximum)	kWth	4.70
Cold output (maximum)	kWc	6.11
Fuel heat input	kWth	10.0
Fuel consumption (light fuel oil)	kg/h	0.857
Electrical efficiency	%	35.0
Thermal efficiency	%	47.0
CHP efficiency	%	52.0
Total running hours (scenario **b2)**)	hours/year	2,520.0

Table 3: Basic Features of CHP Unit

The following annual quantities of energy are expected to be generated when the CHP unit is in operation (900 hours in winter and 1620 hours in summer):

- electric energy: (2,520.0 h) x (3.5 kWel) = 8,820.0 kWh
- thermal energy: (900.0 h) x (4.7 kWth) = 4,230.0 kWh
- cooling energy: (1,650.0 h) x (6.11 kWc) =10,081.5 kWh

CHP system operation in the way described above has the following expected annual fuel consumption:

(0.857 kg/h) x (2,520.0 h) = 2,159.64 kg/year

The remaining thermal energy required during the winter period (8,420.3 kWh) will be generated by a backup boiler of an effective rated output of 34.32 kWth (= 39.02 – 4.7), and an average efficiency of 83%. The boiler is expected to consume a total of:

{(8,420.3 kWh) / 83%} x 3600 / 42000 = 869.57 kg/year

Similarly, the remaining cooling energy required during the summer months (3,718.82 kWh) will be generated by means of air conditioning units running on electricity. The electric energy required to meet the above cooling load demand amounts to:

(3,718.82 kWh) / (3.0) = 1,239.60 kWh

Consequently, during the summer, 413.20 kWh of electricity will have to be purchased every two months.

Also, during the cogeneration system's operating period, a total of 3600 kWh-el of electricity will be for sale during non-peak load hours.

D. Economic Evaluation of Investment

D.1.1 General economic data

The following assumptions have been made in order to determine the investment cost of the CHP system in question, including auxiliary equipment necessary (e.g. conventional hot-water boiler):

- The specific cost (equipment + installation) of a small-scale CHP system (under 50 kWel), including a power generator and a heat recovery boiler, is 1,400 €/kWel.
- The specific cost of an integrated absorption chiller system is 150 €/kW.
- Sundry expenses of the CHP system amount to 10% of the cost balance.
- The cost of a conventional boiler with a burner has not been taken into account, as it would be applicable even if there were no cogeneration system and would, in fact, be higher.

Moreover, the following values apply to the cost of fuel and electricity:

- Cost of light fuel oil: 0.95 €/l, or 1.09 €/kg
- Cost of purchasing electricity from the grid (including fuel cost adjustment):
  - under 120 kWh: 0.1423 €/kWh
  - from 120 to 320 kWh: 0.1501 €/kWh
  - from 320 to 500 kWh: 0.1544 €/kWh
  - from 500 to 1000 kWh: 0.1585 €/kWh
  - over 1000 kWh: 0.1602 €/kWh
- Cost of selling electricity to the grid: 0.050 €/kWh

D.2 CHP system designed for base heat load

D.2.1 Annual operating results of cogeneration system

Based on the above, the total investment cost of said CHP system is estimated to be approximately **€9,596.4**, broken down as follows:

Cost of cogeneration system (= 1,400 x 5.25)	€7,350.0
Cost of absorption chiller system (= 150 x 9.16)	€1,374.0
Sundry expenses (= 0.1 x 8,724.0)	€872.4

The ‘operating results’ of the cogeneration system’s operation are determined by comparing the system’s annual running costs (fuel and maintenance costs) against the financial gains from generating part or all of the heat or electricity required.

a) Cost of fuel

If the CHP system under investigation were to be used, the only applicable charges would be those arising from the operation of the system and the backup boiler (fuel cost), the annual amounts of which would be:

- from CHP system: (2,768.8 kg) x (1.09 €/kg) = 3,018.0 €/year
- from boiler: (651.1kg) x (1.09€/kg) = 709.7 €/year

Total: 3,727.7 €/year

b) Maintenance cost

The maintenance cost is assumed to be 2% of the total investment cost, that is:
(€9,596.40) x 2% = 191.9 €/year

c) Financial gains

The CHP system’s operation generates the following quantities of energy, which would otherwise be provided by means of a conventional boiler and by “purchasing” them from the grid:

- electricity (without cooling): 6,109.92 kWh-el
  (for cooling): 3,141.00 kWh-el
- heat: 6,345.00 kWh-th

The corresponding financial gains are:

- for electricity: 1,459.41 €/year
- for heat: 714.22 €/year

Total: 2,173.64 €/year

There are also financial gains to be had from the sale of surplus electricity, which amount to:

(5,594.58 kWh-el) x (0.05 €/kWh-el) = 279.73 €/year

d) Operating results

Based on the above, the “operating results” of the operation of the CHP system are as follows:

- (3,727.7 + 191.9) **+** (2,173.64 + 279.73) = **- 1,466.23 €/year**

D.2.2 Conclusions

Given the data provided in the two previous paragraphs, the CHP system’s operating results are negative. The CHP system in question will, consequently, be operating at a loss and this investment can not, therefore, be justified even given a very high investment ratio (100% subsidisation).

- ***Non-subsidised project***

Indicatively, assuming no subsidy and an interest rate of 8%, the NPV of the project above over 20 years would be **€-23,992.1.**

The NPV over a 20-year period is zero when the cost of fuel oil for cogeneration is only approximately 19.0% of the fuel cost for a conventional boiler, namely 0.207 €/kg.

- ***Subsidised project***

Assuming a 30% subsidy and an interest rate of 8%, the NPV of the project above over 20 years would be **€-21,113.15**, while, with a 60% subsidy, its NPV over 20 years would **€-18,234.23**.

With a 30% subsidy, the net present value over a 20-year period is zero when the cost of fuel oil for cogeneration is approximately 28.75% of the fuel cost for a conventional boiler, namely 0.313 €/kg. Alternatively, the NPV of a project with a 30% subsidy is also zero over 20 years when the average purchasing price of electricity is approximately 147.35% higher than the current price, namely about 0.390 €/kWhel.

D.3 CHP system designed to meet electrical load demands in full

D.3.1 Annual operating results of cogeneration system

Based on the above, the total investment cost of said CHP system is estimated to be approximately **€6,398.1€**, and it is broken down as follows:

Cost of cogeneration system (= 1,400 x 3.50)	€4,900.0
Cost of absorption chiller system (= 150 x 6.11)	€916.5
Sundry expenses (= 0.1 x 5,816.5)	€581.6

The 'operating results' of the cogeneration system's operation are determined by comparing the system's annual running costs (fuel and maintenance costs) against the financial gains from generating part or all of the required heat or electricity.

a) Cost of fuel

If the CHP system under investigation were to be used, the only applicable charges would be those arising from the operation of the system and the backup boiler (fuel cost), the annual amounts of which would be:

- from CHP system: (2,159.6kg) x (1.09€/kg) = 2,353.9 €/year
- from boiler: 869.6kg) x (1.09€/kg) = 947.8 €/year

Total: 3,301.7 €/year

b) Maintenance cost

The maintenance cost is assumed to be 2% of the total investment cost, that is:
(€6,398.10) x 2% = 127.9 €/year

c) Financial gains

The CHP system's operation generates the following quantities of energy, which would otherwise be provided by means of a conventional boiler or by "purchasing" them from the grid:

- electricity (without cooling): 5,220.00 kWh-el
  (for cooling): 3,360.50 kWh-el
- heat: 4,230.00 kWh-th

The corresponding financial gains are:

- for electricity: 2,174.49 €/year
- for heat: 476.15 €/year

Total: 2,650.64 €/year

There are also financial gains to be had from the sale of surplus electricity, which amount to:

(3,600.00 kWh-el) x (0.05 €/kWh-el) = 180.00 €/year

d) Operating results

Based on the above, the "operating results" of the CHP system's operation are as follows:

- (3,301.7 + 127.9) **+** (2,650.64 + 180.00) = **- 598.96 <u>€/year</u>**

D.3.2 Conclusions

Given the data provided in the two previous paragraphs, the CHP system's operating results are negative. The CHP system in question will, consequently, be operating at a loss and this investment can not, therefore, be justified even given a very high investment ratio (100% subsidisation).

- ***Non-subsidised project***

Given no subsidy and an interest rate of 8%, the NPV of the project above over 20 years is **€-12,280.14.**

The NPV over a 20-year period is zero when the cost of fuel oil for cogeneration is only approximately 48.9% of the fuel cost for a conventional boiler, namely 0.51 €/kg.

- ***Subsidised project***

Assuming a <u>30%</u> subsidy and an interest rate of 8%, the NPV of the project above over 20 years would be **€-10,360.71**, while with a <u>60%</u> subsidy its NPV over 20 years would be **€-8,441.28**.

With a 30% subsidy, the net present value over a 20-year period is zero when the cost of fuel oil for cogeneration is approximately 55.2% of the fuel cost for a conventional boiler, namely 0.60 €/kg.

5.4.2 Assessment of CHP Potential in Blocks of Flats

A. Introduction

The prospect of implementing a small heating/cooling and electricity cogeneration system in order to meet all or part of such needs in blocks of flats in Cyprus shall be investigated in this study from a technical and economic perspective.

More specifically, this system is expected to operate during periods when there is a demand for thermal or cooling energy, at which times it will be functioning as a cogeneration system with a high total efficiency rate (over 80%). For this to occur, cooling load demands must be met using thermal rather than electric energy (conventional air conditioning units), in other words using absorption chillers to convert thermal energy to cooling energy. In addition, the cogeneration unit must be in operation for as many hours as possible so that the cost of the system may be recovered. It is not advisable to operate the cogeneration unit for electricity generation purposes alone, as its estimated operating cost is particularly high – higher than the cost of purchasing electricity from the grid.

Given that in such cogeneration systems thermal efficiency is usually "significantly" higher than electrical efficiency, the system's operating load should be based on heating needs. Any surplus electricity resulting from this operating method will be supplied to the grid.

A cogeneration system is expected to partially or totally eliminate a) electric energy supply for meeting electricity needs and cooling/heating needs – when these are met using air conditioning units – and b) the consumption of light fuel oil used in hot water heating boilers.

For the purposes of this study, a typical block of flats is assumed to comprise eight (8) flats, each 113 m^2 (average for the period 1991–2006; source: Statistical Service of the Republic of Cyprus). Therefore, the block of flats under evaluation has a total area of **904 m^2.**

B. Calculation Parameters

The absence of detailed data makes it impossible to precisely determine the heat, cooling and electrical loads required. Furthermore, it is unclear how the heat load demands necessary are met (whether using hot-water boilers or air conditioning units) and also what percentage of electricity consumption corresponds to cooling load demands (operation of air conditioning units).

The figures to be used in the relevant calculations are mentioned in this paragraph and have been obtained:

- from available statistics
- through assumptions based on relevant experience or data from Greece, while also taking into consideration the climatic and other characteristics peculiar to Cyprus (higher temperatures both in the winter and in the summer).

The thermal and cooling capacity required is estimated by means of heating and cooling degree days based on the coldest and hottest month, respectively. More specifically, heating is expected to be required when external temperatures drop below the equilibrium temperature of 18°C. Similarly, cooling (air conditioning) is expected to be required when external temperatures rise above 22°C. <u>Maximum peak load, whether heat or cooling, is derived from the coldest and hottest day, respectively, and it is directly linked to the running hours of heating and air conditioning systems</u>.

For the purposes of this study the COP of the absorption chiller is assumed to be 1.3, which is a typical value for absorption chillers running on hot water at a temperature of 95°C. The absorption chiller's cold output is, therefore, 1.3 times the heat input by the cogeneration system. Note that the typical COP value for conventional technology chillers is 3.0.

Calculations are based on a typical block of flats in Cyprus, given 'mean' environmental data obtained from the weighted averages of the values corresponding to the areas of Nicosia, Larnaca (including Famagusta area), Limassol and Paphos (weighting coefficients: 0.35, 0.28, 0.23 and 0.14, respectively).

The following information has been taken into account in these calculations:

<u>for calculating the installation's heat load</u>

a) total annual heating degree days: 791.5, at an equilibrium temperature of 18°C,

b) total heating degree days during the coldest month (February): 182.6 (at the same equilibrium temperature),

c) minimum temperature during coldest month: 1.9°C, based on data obtained from the Meteorological Service of Cyprus,

d) hours the heating system is in operation each day: 5,

e) months the heating system is in operation each year: 5 (November to March)

f) specific annual heating energy consumption for heating: 50 kWh/m^2/year (it is considered to be lower than that of a detached house because many parts of a block of flats are 'interior spaces').

g) ratio of hot-water heat load to heating: 0.1

<u>for calculating the installation's cooling load</u>

h) total annual cooling degree days: 572, at an equilibrium temperature of 22°C

i) total cooling degree days during the hottest month (July): 166.7 (at the same equilibrium temperature),

j) hours the air conditioning system is in operation each day: 8,

k) months the air conditioning system is in operation each year: 6 (May to October)

l) specific annual cooling energy consumption for air conditioning: 20% higher than specific heating energy consumption, in kWh/m^2/year (in Greece, in Zone A areas, the cooling load is approximately equal to the heat load)

m) absorption chiller heat capacity required equal to cooling capacity output.

<u>for calculating the installation's electrical load</u>

n) specific electric energy equal to 28.7 kWh/m^2/year (this value does not include electricity consumed to meet heat and cooling load demands and it is based on data specific to the months of October and November, which is a period without particularly high cooling and heat loads (source: Statistical Service of the Republic of Cyprus) – the value is also typical of a modern residence in Zone A in Greece).

Moreover, the diversity factor for all loads is equal to 0.85.

Resultant loads for blocks of flats, based on the information above, are provided below:

1) Electrical Load

(given diversity factor = 0.85)

- Total annual electric energy (excluding air conditioners): 22,283.60 kWh
- Peak electrical capacity (4 hours/day): 17.68 kW
- Average electrical capacity for the rest of the period (0.35 per flat): 2.80 kW

2) Heat Load

(given diversity factor = 0.85)

- Annual thermal energy for heating: 38,420.00 kWh
- Annual thermal energy for hot water: 3,842.00 kWh
- Total annual thermal energy: 42,262.00 kWh
- Peak heat capacity (coldest day): 130.34 kWth
- Heat capacity on average day in coldest month: 51.93 kWth
- Average heat capacity of period, excluding coldest month: 45.32 kWth
- Average annual heat capacity: 46.95 kWth

3) Cooling Load

- Annual cooling energy: 46,104.00 kWh
- Peak cooling capacity (hottest day): 141.47 kWc
- Cooling capacity on average day in hottest month: 48.16 kWc
- Average cooling capacity of period, excluding hottest month: 24.20 kWc
- Average annual cooling capacity: 28.46 kW

C. Cogeneration system dimensioning

A complete cogeneration system is required, with the equipment necessary to generate electricity and thermal/cooling energy. More specifically, in the case under investigation, the power generation technology needed is a light fuel oil-fired internal combustion engine and a boiler that will recover heat from the engine's cylinder liners and exhaust gases in order to produce hot water. There must also be an indirect-fired absorption chiller that will use hot water from the cogeneration unit, as well as a standby hot-water boiler (provided it has not already been included in the basic equipment of the cogeneration system) if the criterion for dimensioning the cogeneration system is meeting electrical load needs, as described below.

The dimensioning of the household cogeneration unit can be based on one of the following criteria:

iii. meeting the required heat load of the block of flats in full, with the design heat load being equal to the highest value between the heat load for heating and that for operating the absorption chiller.

iv. meeting the required electrical load in full and any heat load that may occur.

Note that in a typical block of flats, the heat load (for heating and cooling) is expected to be "significantly" higher than the electrical load. Consequently, with design criterion (i) above, the operation of the cogeneration system is expected to yield surplus energy which can be supplied to the grid. In contrast, with design criterion (ii) above, the operation of the cogeneration system is expected to result in substantial shortage of thermal energy, which must be made up for using a backup conventional boiler.

The above make it obvious that a household's total electricity and thermal/cooling energy needs can be met with design criterion **(i)**. However, the cogeneration unit required in this case is expected to be substantially larger than the system selected under design criterion (ii) and, therefore, entails a higher investment cost.

C.1 CHP system designed to meet heat load demands

In this case, the cogeneration unit must be in operation in winter and summer in order to meet the household's heat and cooling load demands required. The cogeneration system's operation can take one of the following forms:

a) interrupted operation at full load for a specific number of hours a day (peak load dimensioning). In this case, the cogeneration system's running hours will be significantly fewer than the customary running hours of the heating and air conditioning systems (that is, approximately 2.2 hours instead of 6 and 1.8 hours instead of 9, respectively).

b) "continuous" operation at partial or full load.

In case **a)** (interrupted operation), the electricity required to meet the needs of the block of flats during periods of cogeneration system inactivity will be supplied by the grid. The building's high electrical loads (e.g. cooker, iron, washing machine, etc.) should, therefore, be planned for times when the cogeneration system will be running so as to minimise electricity "absorbed" from the grid as much as possible. In this case, the cogeneration system is expected to be big and costly, with a comparatively small number of running hours per year.

In contrast, in case **b)** (continuous operation) the cogeneration system can be dimensioned with respect to the peak heat load and can run mainly at partial load, only running at full heat load during expected peak hours (minimum or maximum environmental temperatures) (scenario **b1)**). The unit will be the same size and will cost the same as in case a) above, but will have many more running hours during which the system can be taken advantage of. Regardless of the mode of operation (partial or full load), the building's electrical load is expected to be met in full and the surplus electricity will, once again, be supplied to the grid. Note that if the partial load expected is much smaller than the system's nominal load, this will significantly reduce the efficiency of the CHP unit, which must be taken into consideration.

Alternatively, for continuous operation, the cogeneration system can be dimensioned in order to meet the 'base' heat load (scenario **b2)**). Any additional thermal or cooling energy required to meet the corresponding peak needs will be supplied by means of a backup hot-water boiler running on light fuel oil and conventional air conditioning units. In this case, the cogeneration system is expected to be relatively small and inexpensive, and to be able to run continuously during periods when heating or cooling (air conditioning) may be required throughout the year.

C.1.1 CHP system designed for peak heat load

The basic features of a household CHP unit running at full load are shown in the table below.

Power output	kWel	97.06
Surplus power output (maximum)	kWth	130.34
Cold output (maximum)	kWc	141.47
Fuel heat input	kWth	301.00
Fuel consumption (light fuel oil)	kg/h	23.77
Electrical efficiency	%	35.0
Thermal efficiency	%	47.0
CHP efficiency	%	82.0

Table 1: Basic Features of CHP Unit

During summer, the CHP unit's maximum required heat output for meeting peak cooling load demands is 108.82kWth. In this case, the unit will be running at around 83.5%partial load.

The cogeneration system's running hours at the maximum required thermal and cooling capacity during the corresponding periods of time (winter and summer) are shown in the table below. This mode of operation is believed to meet the annual thermal and cooling energy demands in full, while also generating significantly higher power during the short operating period than the average power required.

Total running hours (scenario **a)**)	hours/year	649.4
- for heating	hours/year	324.2
- for cooling	hours/year	325.2

Moreover, for the system to be in "continuous" operation (e.g. 16 hours/day), it must run at a very low load, thereby significantly reducing the efficiency of the CHP unit.

A CHP system of this size does not merit further economic evaluation, regardless of the running hours and operation mode, given that the investment cost is exceptionally high and cannot be borne by the average household. Indicatively, it is estimated that the cost of the investment shall exceed 260k€ (around 32.5 k€ per household).

C.1.2 CHP system designed for base heat load

The CHP system's design 'base heat load' is based on the system being in operation 'continuously' throughout the daily running period of the heating and cooling systems, namely 6 hours/day in winter and 9 hours/day in summer.

In this case, the design load, which will also be the full load of the CHP unit, is assumed to be the average annual heat capacity to meet the annual heat load demands, except for the coldest month, and the annual cooling load demands, except for the hottest month, given the running hours above.

Therefore the capacities are as follows:

- Winter period
  (30,195.66kWh /year) / {4 months x 30 days x 6 hours} = 41.94kWth
- Summer period

(9,778.04 kWh/year) / {5 months x 30 days x 9 hours} = 24.97kWc
(or 19.21kWth)

More specifically, the heat capacity of the cogeneration system could be the smaller of the two presented above.

At times in summer when the cooling capacity required to meet the cooling load of a block of flats is greater than the power generated by the CHP system, use must be made of conventional air conditioners running on electricity. The right size of CHP unit should, therefore, be found, so that enough electricity is generated to cover the electricity required to run the air conditioners, which, together with the CHP system, will meet the cooling load demands of an average day in the hottest month (**48.16kWc**). Any additional power demand will be met by the grid.

The CHP unit resulting from the above will have a heat capacity of **28.65kW**. In this case, there is the following surplus electrical power:

- generated: 21.33kWel
- consumed (excluding air conditioners): 17.68kWel
- surplus (for use by air conditioners): 3.65kWel
-

The cooling load resulting from the cooling systems (conventional air conditioners and absorption chiller) is as follows:

- conventional air conditioning units

  (3.65kWel) x (3.0kWc/kWel) =10.95kWc
- absorption chiller

(28.65kWth) x (1.3kWc/kWth) =37.24kWc

The total cooling load demand that can be met is, therefore:

37.24kWth (by the CHP unit) + 10.95kWth (by the air conditioners) = 48.19kWth

At times in winter when the heating capacity required to meet the heat load of a block of flats is greater than the power generated by the CHP system, use must be made of a conventional backup hot-water boiler running on light fuel oil. The boiler's useful heat load must be high enough so that, when operating together with the CHP system, the block of flats' peak heat load can be met.

The boiler's maximum heat capacity will, therefore, be:

(130.34kWth) – (28.65kWth) = 101.69kWth

and its efficiency ratio at average operating is assumed to be equal to 83%.

The cogeneration system resulting from the above information has the following technical features at full load:

Power output	kWel	21.33
Heat output (maximum)	kWth	28.65
Cold output	kWc	37.24
Fuel heat input	kWth	60.96
Fuel consumption (light fuel oil)	kg/h	5.22
Electrical efficiency	%	35.0
Thermal efficiency	%	47.0
CHP efficiency	%	52.0
Total running hours (scenario **b2)**)	Hours/year	2,520.0

Table 2: Basic Features of CHP Unit

In winter the above CHP unit will be operating for a total of 900 hours at an average heat capacity of 28.65kWth kWth (full load), generating a total of 25,785.0kWh-th in thermal energy, while in the summer it will be operating for 1350 hours at an average cooling capacity of 24.20kWc, namely 18.61 kWh in heat capacity (65% load, with 72% efficiency, assuming a 10% drop, 4% in electricity and 6% in thermal efficiency) and for a period of 270 hours at an average heat capacity of 37.24kWc, i.e. heat output 28.65 kWth (full load) generating a total of 42,724.8kWh-c in cooling energy.

CHP system operation in the way described above has the following expected annual fuel consumption:

- Winter period: (900 h) x (5.22 kg/h) = 4,698.0kg
- Summer period: (1350 h) x (5.22kg/h) x (65%) x (0.82)/(0.72) = 5,216.7kg

:70h) x (5.22kg/h) = 1,409.4kg

11,324.1kg

Similarly, the backup boiler will provide the remaining thermal energy required by the block of flats, its resultant annual useful heat being equal to:

(42,262.0 kWh/year) - (25,785.0 kWh/year) = 16,477.0 kWh/year

In order to generate the above thermal energy, the backup boiler will consume the following quantity of fuel:

(16,477.0 kWh/year) x 3600 / {83% x (42,000.0 kJ/kg)} = 1,701.6 kg

Moreover, the electricity demands of a block of flats can be met in full when the above CHP system is in operation, except for some odd moments during summer, when electricity will have to be "drawn" from the grid in order to meet peak cooling load demands. The building's peak electrical load is expected to occur during the period when the CHP system is in operation, and during the times when the CHP system is inoperative, electricity will be obtained from the grid at an average capacity of 2.8 kWel.

During the summer period, excluding the hottest month (1350 hours), when the electricity generated will be used in its entirety to run the air conditioners, the CHP system will have an average power output of:

{ (18.61 kW) / 41% } x 31% = 14.07 kWel.

Consequently, there will only be surplus power during non-peak periods (750 h/year):

- electrical capacity: (14.07 kWel) – (2.80 kWel) = 11.27 kWel
- electrical energy: (15.51 kWel) x (750 h) = 8,452.50 kWh

During the winter period (900 hours), the CHP system will have an average power output of 21.33 kWel (full load) at all times, therefore resulting in a surplus:

a) for peak electricity hours (4 hours/day)

- electrical capacity: (21.33 kWel) – (17.68 kWel) = 3.65 kWel
- electrical energy: (3.65 kWel) x (600 h) = 1,190.00 kWh

b) for the CHP system's remaining running hours

- electrical capacity: (21.33 kWel) – (2.80 kWel) = 18.53 kWel
- electrical energy: (18.53 kWel) x (300 h) = 5,559.00 kWh

Consequently, given the expected running time of the above cogeneration system, the resultant electricity surplus is equal to 15,201.5 kWh-el, which can be sold to the grid.

C.2 CHP system designed to meet electrical load demands

In such a case, the CHP system is chosen so that it meets peak electricity demands during the period when air conditioners are not in operation, namely 17.68 kWel. The unit will be running at full load throughout the heating and cooling periods, and the surplus electricity generated during non-peak load hours will be supplied to the grid.

The basic features of such a CHP unit running at full load are shown in the table below.

Power output	kWel	17.68
Heat output (maximum)	kWth	23.74
Cold output (maximum)	kWc	30.86
Fuel heat input	kWth	50.51
Fuel consumption (light fuel oil)	kg/h	4.33
Electrical efficiency	%	35.0
Thermal efficiency	%	47.0
CHP efficiency	%	52.0
Total running hours	hours/year	2,520.0

Table 3: Basic Features of CHP Unit

During winter (900 hours), the CHP unit will be running continuously at full load and is expected to generate the following amounts of energy:

- electrical energy: (900.0 h) x (17.68 kW) = 15,912.0 kWh-el
- thermal energy: (900.0 h) x (23.74 kW) = 21,366.0 kWh-th

Furthermore, there will be an electrical energy surplus during non-peak load hours, amounting to:

(17.68 kW – 2.8 kW) x (300 h) = 4,464.0 kWh-el/year

During the summer period, excluding the hottest month (1350 h), the CHP unit's load will be restricted so as to meet the average cooling load of the above period (24.20 kWc), which corresponds to a heat capacity of 18.61 kWc and an electrical capacity of 14.01 kWel (78% load, with 78% efficiency, assuming a 4% drop: 1.5% in electrical efficiency and 2.5% in thermal efficiency). The following quantities of energy are expected to be generated during this period:

- electrical energy: (1,350.0 h) x (14.01 kW) = 18,913.5 kWh-el
- cooling energy: (1,350.0 h) x (24.20 kW) = 32,670.0 kWh-c

Furthermore, there will be an electrical energy surplus during non-peak load hours in the above period, amounting to:

(14.01 kW – 2.8 kW) x (750 h) = 8,407.5 kWh-el/year

During the hottest month of the summer period (270 hours), the CHP unit will be running continuously at full load and is expected to generate the following amounts of energy:

- electrical energy: (270.0 h) x (17.68 kW) = 4,773.6 kWh-el
- cooling energy: (270.0 h) x (30.86 kW) = 8,332.2 kWh-c

Furthermore, there will be an electrical energy surplus during non-peak load hours in the above period, amounting to:

(17.68 kW – 2.8 kW) x (150 h) = 2,232.0 kWh-el/year

The CHP system's operation has the following expected annual fuel consumption:

(4.33 kg/h) x (2,520.0 h) = 10,911.6 kg/year

The remaining thermal energy required during the winter period (20,896.0 kWh) will be generated by a backup boiler with an effective rated output of 106.60 kWth (= 130.34 – 23.74), and an average efficiency of 83%. The boiler is expected to consume a total of:

{ (20.896.0 kWh) / 83% } x 3600 / 42000 = 2,157.93 kg/year

Similarly, the remaining cooling energy required during the summer months (5,101.80 kWh) will be generated by means of air conditioning units running on electricity. The electricity required to meet the above cooling load demand amounts to:

(5,101.80 kWh) / (3.0) = 1,700.60 kWh

D. Economic Evaluation of Investment

D.1.1 General economic data

The following assumptions have been made in order to determine the investment cost of the CHP system in question, including the necessary auxiliary equipment (e.g. conventional hot-water boiler):

- The specific cost (equipment + installation) of a small-scale CHP system (under 50 kWel), including a power generator and a heat recovery boiler, is 1,400 €/kWel.
- The specific cost of an integrated absorption chiller system is 150 €/kW.
- Sundry expenses of the CHP system amount to 10% of the cost balance.
- The cost of a conventional boiler with a burner has not been taken into account, as it would be applicable even if there were no cogeneration system and would, in fact, be higher.

Moreover, the following prices apply to the cost of fuel and electricity:

- Cost of light fuel oil: 0.95 €/l, or 1.09 €/kg
- Cost of purchasing electricity from the grid (including fuel cost adjustment):
  - under 120 kWh: 0.1423 €/kWh
  - from 120 to 320 kWh: 0.1501 €/kWh
  - from 320 to 500 kWh: 0.1544 €/kWh
  - from 500 to 1000 kWh: 0.1585 €/kWh
  - over 1000 kWh: 0.1602 €/kWh
- Cost of selling electricity to the grid: 0.050 €/kWh

D.2 CHP system designed for base heat load

D.2.1 Annual operating results of cogeneration system

Based on the above, the total investment cost of this CHP system is estimated to be approximately **€38,992.8**, and it is broken down as follows:

Cost of cogeneration system (= 1,400 x 21.33)	€29,862.0
Cost of absorption chiller system (= 150 x 37.24)	€5,586.0
Sundry expenses (= 0.1 x 35,448.0)	€3,544.8

The ‘operating results’ of the cogeneration system’s operation are determined by comparing the system’s annual running costs (fuel and maintenance costs) with the financial gains from generating part or all of the required heat or electricity.

a) Cost of fuel

If the CHP system under examination were to be used, the only applicable charges would be those arising from the operation of the system and the backup boiler (fuel cost), the annual amounts of which would be:

- from CHP system: (11,324.1 kg) x (1.09 €/kg) = 12,343.3 €/year
- from boiler: (1,701.6kg) x (1.09€/kg) = 1,854.7€/year

Total: 14,198.0 €/year

b) Maintenance cost

The maintenance cost is assumed to be 2% of the total investment cost, that is:

(38,992.8 €) x 2% = 779.8 €/year

c) Financial gains

The CHP system's operation generates the following quantities of energy, which would otherwise be provided by means of a conventional boiler and by "purchasing" them from the grid:

- electricity: (without cooling): 28,749.10 kWh-el
  (for cooling): 14,241.60 kWh-el
- heat: 25,785.00kWh-th

The corresponding financial gains are:

- for electricity: 11,201.76 €/year
- for heat: <u>2,902.47€/year</u>

  Total: 14,104.23€/year

There are also financial gains to be had from the sale of surplus electricity, which amount to:

(15,201.50 kWh-el) x (0.05 €/kWh-el) = 760.07 €/year.

d) Operating results

Based on the above, the "operating results" of the CHP system's operation are as follows:

- (14,198.0 + 771.8) **+** (14,104.23 + 760.07) = <u>**- 113.50 €/year**</u>

D.2.2 Conclusions

Given the data provided in the previous two paragraphs, the CHP system's operating results are marginally negative. The CHP system in question will, consequently, be operating at a loss and this investment can, therefore, not be justified even given a very high investment ratio (100% subsidisation).

- ***Non-subsidised project***

Assuming no subsidy and an interest rate of 8%, the above project's NPV over 20 years would be **€-40,107.3.**

The NPV over a 20-year period is zero when the cost of fuel oil for cogeneration is only approximately 66.9% of the fuel cost for a conventional boiler, namely 0.73 €/kg.

- ***Subsidised project***

Assuming a <u>30%</u> subsidy and an interest rate of 8%, the above project's NPV over 20 years would be **€-28,409.45**, while with a <u>60%</u> subsidy its NPV over 20 years it would be **€-16,711.61€**.

Assuming a 30% subsidy, the net present value over a 20-year period is zero when the cost of fuel oil for cogeneration is approximately 73.3% of the fuel cost for a conventional boiler, namely 0.80 €/kg.

D.3 CHP system designed to meet electrical load demands in full

D.3.1 Annual operating results of cogeneration system

Based on the above, the total investment cost of this CHP system is estimated to be approximately **€32,319.1**, and it is broken down as follows:

Cost of cogeneration system (= 1,400 x 17.68)	€24,752.0
Cost of absorption chiller system (= 150 x 30.86)	€4,629.0
Sundry expenses (= 0.1 x 29,381.0)	€2,938.1

The ‘operating results’ of the cogeneration system’s operation are determined by comparing the system’s annual running costs (fuel and maintenance costs) with the financial gains from generating part or all of the required heat or electricity.

a) Cost of fuel

If the CHP system under examination were to be used, the only applicable charges would be those arising from the operation of the system and the backup boiler (fuel cost), the annual amounts of which would be:

- from CHP system: (10,911.6 kg) x (1.09 €/kg) = 11,893.6 €/year
- from boiler: (2,157.9 kg) x (1.09 €/kg) = 2,352.1 €/year

Total: 14,245.7 €/year

b) Maintenance cost

The maintenance cost is assumed to be 2% of the total investment cost, that is:
(€32,319.10) x 2% = 646.4 €/year

c) Financial gains

The CHP system’s operation generates the following quantities of energy, which would otherwise be provided by means of a conventional boiler and by “purchasing” them from the grid:

- electricity: (without cooling): 24,495.60 kWh-el
  (for cooling): 13,667.40 kWh-el
- heat: 21,366.00 kWh-th

The corresponding financial gains are:

- for electricity: 9,747.12 €/year
- for heat: 2,405.05 €/year

Total: 12,152.17 €/year

There are also financial gains to be had from the sale of surplus electricity, which amount to:

(15,103.50 kWh-el) x (0.05 €/kWh-el) = 755.17 €/year

d) Operating results

Based on the above, the “operating results” of the CHP system’s operation are as follows:

- (14,245.7 + 646.4) **+** (12,152.17 + 755.17) = **- 1,984.76 €/year**

D.3.2 Conclusions

Given the data provided in the previous two paragraphs, the CHP system’s operating results are negative. The CHP system in question will, consequently, be operating at a loss and this investment can, therefore, not be justified even given a very high investment ratio (100% subsidisation).

- ***Non-subsidised project***

Assuming no subsidy and an interest rate of 8%, the above project's NPV over 20 years would be **€-51,806.31.**

The NPV over a 20-year period is zero when the cost of fuel oil for cogeneration is only approximately 55.6% of the fuel cost for a conventional boiler, namely 0.60 €/kg.

- ***Subsidised project***

Assuming a 30% subsidy and an interest rate of 8%, the above project's NPV over 20 years would be **€-42,110.58**, while with a 60% subsidy its NPV over 20 years it would be **€-32,414.85**.

With a 30% subsidy, the net present value over a 20-year period is zero when the cost of fuel oil for cogeneration is approximately 64.0% of the fuel cost for a conventional boiler, namely 0.69 €/kg.

6 CHP PENETRATION IN CYPRUS'S ENERGY SYSTEM FOR THE YEARS 2010, 2015 AND 2020 USING THE MARKAL ENERGY MODEL

MARKAL is an energy market simulation/optimisation model currently used in 40 countries. It is continuously developing and evolving as part of the International Energy Agency's Energy Technology Systems Analysis Programme (ETSAP).

The MARKAL model is based on useful energy demand whose forecast is exogenous. Assuming trends in useful energy demand (space heating and cooling, lighting, etc.) as an input value and combining them with technical and economical trends in energy technologies within the time horizon assumed for the solution, the model optimises the technology/fuel combination to meet energy demands, while also achieving energy policy objectives (gaseous pollutant emissions, energy saving, etc.). The solution for each scenario under examination is obtained by minimising the overall cost of the energy system within the time horizon assumed. This solution is, therefore, the optimal technical and economical alternative for implementing energy policy at the national economy level. The conditions that must apply for energy technology penetration from the investor's perspective must be examined separately and are usually determined using parametric analysis (see Chapter 5). Generally speaking, it is advisable to find economic incentives for investors to ensure that the desired penetration of technologies is achieved at the national economy level.

MARKAL model's advantage lies in the fact that it simulates the entire energy sector and also enables all current and future energy technologies to be examined, compared and combined with respect to energy supply and final energy consumption.

The input data required by the model are useful energy demand per economic sector and per end use. A detailed analysis is conducted based on data availability.

The Cypriot energy system was simulated in the MARKAL model with as much detail as possible by arranging the existing energy data as a Reference Energy System.

The useful energy demand trend assumptions incorporated into the Cypriot Energy System are analysed in the following chapter. Various useful energy demand categories per economic sector and per end use are presented in as much detail as possible.

Each of these useful energy demand categories are covered by certain alternative technologies, which may make use of alternative fuels. In this manner, the competition between various technologies and between various fuels is taken into consideration. Where consumption technologies are concerned, use was made of the International Energy Agency's extensive MATTER database, which contains data on the trend over time of a particular technology's efficiency, cost and lifetime.

The data used on each technology include:

- Installation cost in euros/kW
- Variable maintenance and operating costs in euros/kWh
- Efficiency (in the form of required energy input and heat output to generate one unit of electricity).
- Annual availability factor
- Technical lifetime (lifespan)

For the tertiary sector, the demand for space heating, space cooling, hot water and electricity has been analysed with regard to the following spheres of activity:

- o Hotels
- o Hospitals
- o Shopping Centres
- o Office Buildings

For the industrial sector, thermal and cooling energy demands have been analysed with regard to the following spheres of activity:

- o Food Products, Beverages
- o Chemical Industry
- o Wood/timber Industry
- o Agriculture – Animal Production
- o Non-ferrous Metal Ores
- o Non-metallic Mineral Products

In order to determine future trends in energy demand, assumptions are made regarding the trends of factors affecting useful energy demand per use and sector. The main factors are population trends, GDP trends and trends in each sector's economic activity indicator. How these factors behave over time, given a specific demand elasticity and price elasticity, also determines the manner in which useful energy demand per sector and use evolve over time.

The International Energy Agency's forecasts of international petroleum, natural gas and coal price trends have been used for the time horizon for solving the model (up to 2030). The high petroleum price scenario was chosen out of the various scenarios as a likely development. Natural gas prices are directly linked to petroleum prices, while coal prices increased only slightly during the period under study.

The MARKAL energy model has been used so as to assess CHP economic potential under different scenarios. Table 6.1 shows the economic cogeneration potential trends while taking into account the limitations of Cyprus's national energy policy.
For the year 2015, the potential for CHP penetration in the national economy is 124 MWe, of which 15 MWe correspond to the tertiary sector, and more specifically: 11 MWe to hotels, 1 MWe to hospitals and 2 MWe to large office buildings. The industrial sector's potential for the year 2015 is estimated to be 75 MWe.

For the year 2020 there appears to be a significant CHP penetration potential totalling approximately 228 MWe, of which 35 MW correspond to the tertiary sector, and more specifically: 28 MWe to hotels, 3.2 MWe to hospitals and 4 MWe large office buildings and shopping centres. The industrial sector's potential for 2020 is estimated to be 153 MWe, with non-metallic mineral products (cement and brick factories) playing a dominant role. A considerable high-efficiency cogeneration (HE-CHP) potential can be derived from using solid biomass, especially in industry (20 MWe), and biogas (20 MWe).

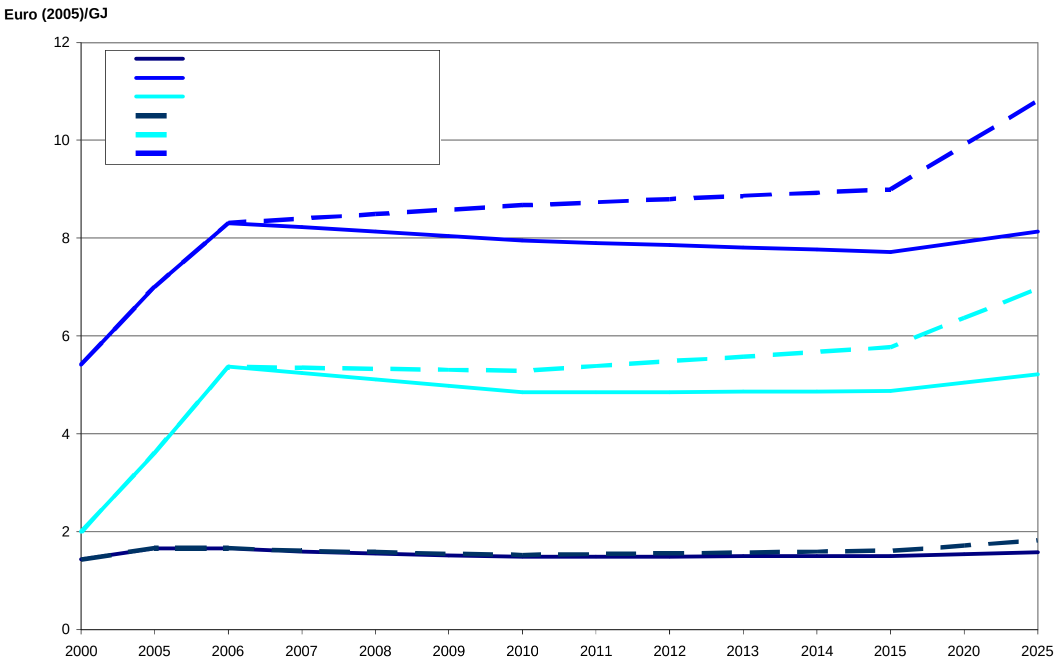
International Energy Agency forecasts on crude oil, natural gas and coal, published in November 2007.

Reference Scenario (€$_{2005}$/GJ)

	2005	2010	2015	2020
Crude oil	7.71	7.95	7.71	7.93
Natural gas	3.61	4.84	4.86	5.04
Coal	1.64	1.47	1.48	1.52

High-Price Scenario (€$_{2005}$/GJ)

	2005	2010	2015	2020
Crude oil	7.71	8.63	8.99	11.13
Natural gas	3.61	5.28	5.64	7.08
Coal	1.64	1.51	1.58	1.81



Trends in international fuel prices, according to IEA (November 2007)

Table 6.1: CHP Economic Potential in Cyprus. Penetration in 2010, 2015, 2020.

Activity Type	Total Fuel Consumption MWh/year			Total Electricity Output MWh/year			Total Heat Output MWh/year			Primary Energy Saving MWh/year			Electricity – Installed Capacity MWe			Heat – Installed Capacity MWth		
	2010	2015	2020	2010	2015	2020	2010	2015	2020	2010	2015	2020	2010	2015	2020	2010	2015	2020
Hotels	77156	246901	609915	24690	79008	195173	37666	120531	297746	19289	61725	152479	3.5	11.3	27.9	5.4	17.2	42.5
Hospitals	6823	21834	69160	2183	6987	22131	3934	12589	39876	1706	5459	17290	0.3	1.0	3.2	0.6	1.8	5.7
Office buildings – Shopping centres	14454	46253	87359	4625	14801	27955	7540	24129	45574	3614	11563	21840	0.7	2.1	4.0	1.1	3.4	6.5
Tertiary Sector Total	98434	314988	766434	31499	100796	245259	49141	157250	383196	24608	78747	191609	4.5	14.4	35.0	7.0	22.4	54.7
Food products, beverages and tobacco	115202	368647	772437	31105	99535	208558	62787	200918	420989	23596	75506	158210	4.4	14.2	29.8	9.0	28.7	60.1
Non-metallic mineral products	64474	1413962	2827924	16118	353491	706981	35464	777757	1555514	11378	249523	499045	2.3	50.4	100.9	5.1	111.0	222.0
Non-ferrous metals	2168	216810	481800	694	69379	154176	1526	152650	339221	576	57633	128073	0.1	9.9	22.0	0.2	21.8	48.4
Industry Total	181844	1999419	4082162	47917	522404	1069715	99777	1131324	2315724	35550	382662	785329	6.8	74.5	152.6	14.2	161.4	330.4
Agriculture – Animal production	121524	388878	442292	38888	124441	141534	67048	214554	244023	30381	97220	110573	5.5	17.8	20.2	9.6	30.6	34.8
Biogas	65889	210845	239805	21084	67470	76738	35736	114356	130064	16472	52711	59951	4.0	12.8	14.6	6.8	21.8	24.7
Waste treatment and landfill sites	25272	80872	91980	8087	25879	29434	13707	43863	49887	6318	20218	22995	1.5	4.9	5.6	2.6	8.3	9.5
Total	492963	2995001	5622673	147475	840991	1562679	265409	1661346	3122895	113330	631557	1170457	22.4	124.4	228.0	40.2	244.6	454.2

Table 6.2: Total energy generated by CHP plants

Total energy generated by CHP plants	2010	2015	2020
Electricity (MWh)	147475	840991	1562679
Heat (MWh)	265409	1661346	3122895

Table 6.3: Total fuel consumed by CHP plants

Total fuel consumed by CHP plants	2010	2015	2020
Petroleum products (MWh)	395726	2683841	5240660
Biogas (MWh)	97238	311160	353900
Natural gas (MWh)	0	0	28113

7 ESTABLISHING A NATIONAL STRATEGY FOR COGENERATION

7.1 Analysis of barriers preventing realisation of national potential for combined heat and power in Cyprus

7.1.1 Developments in legal framework on CHP in Cyprus

In 2003, the Republic of Cyprus passed a number of laws concerning the liberalisation of the energy market, RES, energy savings and CHP.

The most important of these laws is "**Law 122(I) of 2003 Regulating the Electricity Market"**, which essentially incorporates EU Directive 96/92/EC concerning common rules for the internal market in electricity, which was published in the Government Gazette on 25.07.2003.

The Law's primary principle is to regulate Cyprus's electricity market and it mainly focuses on establishing an energy regulatory authority and system operator, as well as a new licensing system for the generation, transmission, distribution and supply of electricity. Furthermore, the law regulates access to the transmission and distribution systems, etc.
Combined Heat and Power is defined in Article 2 of the Law as "*the simultaneous generation of utilisable heat and electricity from an integrated thermodynamic process, in which overall operating efficiency and the unified thermodynamic process satisfy such technical, operational, economic and environmental criteria as may be specified by the Minister from time to time, following consultations with CERA*".

In Article 86, paragraphs 1, 2 and 3, the Law also resolves serious issues regarding independent producers' access to the Grid, as required by the Directive.
In addition, Article 89 states that the "*regulatory decision or Regulations issued pursuant to Article 88 may impose on any licence holder the obligation to make any arrangements necessary to ensure that, in any calendar year, said licence holders shall have at their disposal a specific amount of electricity from power stations that have been selected through a tendering procedure and which use as their primary fuel source RES or operate as <u>CHP plants</u>*".

Such arrangements entail securing electricity supply and ensuring regularity of supply, quality and prices, use of domestic energy sources and protection of the environment.

On 18.04.2003, after being adopted by Parliament, the Law "**Promoting and Encouraging RES Use and Energy Savings**" was issued by the Cypriot Government.

Pursuant to this Law, a special fund shall be established for subsidising or financing the generation or purchase of electricity, plant facilities and energy saving equipment. Furthermore, the Law makes reference to the special fund's sources of income and its management method, the manner in which its budget will be drawn up and other matters related to its management.
Paragraph (c) of Article 3 stipulates that "*Combined Heat and Power is <u>included</u> in RES and energy savings promotion programmes...*'.

On 05.11.2004, Law 239(I)/2004 "**Regulating the Electricity Market (Amendment)**" was issued, harmonising the country's current legislation with Directive 2003/54/EC of 26 June, 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC.

An important point in the changes that the new law makes to Law 122(•)/2003 is Article 4, which replaces Article 35 of Law 122/2003. The new provision grants an exemption for the "*autoproduction of electricity not exceeding 1 MW by any person(s) of a particular category*", which can also apply to Combined Heat and Power applications.

On 30.04.2004, pursuant to Article 44 of Law 122(•)/2003, the Minister for Commerce, Industry and Tourism issued a Decree stating that "*any consumer with a total consumption equal to or greater than 0.35 GWh during the previous 12 months is an eligible consumer*".

Lastly, on 29.12.2006, after being adopted by Parliament, Law 174(•)/29.12.2006 "**Promoting Combined Heat and Power**" was issued by the Cypriot Government, thereby fully incorporating Directive 2004/8/EC, on the promotion of cogeneration based on a useful heat demand in the internal energy market and amending Directive 92/42/EEC.

In accordance with Directive 2004/8/EC, the Law redefines high-efficiency cogeneration (HE-CHP) as "*primary energy savings of at least 10% when compared with the separate production of heat and electricity*".

The Law states in Article 2, in which a definition of cogeneration is provided, that "*cogeneration is the simultaneous generation of useful thermal and electrical/mechanical energy within a single process*".

Article 8 on 'Grid Issues', and in particular par. 5 thereof, states that the Operator may "*at any moment and without restriction*" reduce HE-CHP-generated electricity that is transmitted to the Grid if the Operator believes that the system's operating conditions render it necessary.

Up until July 2008 only HE-CHP can benefit from Law 174(•)/29.12.2006, while the entitlements of CHP that does not fall within the scope of the definition of HE-CHP remain, on many points, unclear, given that a method for calculating HE-CHP under Directive 2004/8/EC has yet to be adopted at European level.

Article 7(1-3f) refers to financial aid programmes, plans and measures for CHP and HE-CHP. The Cypriot government has established two different aid programmes for CHP systems, spanning from 2007 to 2010.

For 2007, the Special Fund Management Committee for Renewable Energy Sources and Energy Savings issued a "(*De minimis*) *Grant plan for energy savings and encouraging the use of RES for natural and legal persons and for state agencies performing economic activities*", in which Chapter LIII is devoted exclusively to the cogeneration of electricity and heat and/or cooling. *De minimis* aid is granted up to 30% of the eligible budget, within the limits of the highest eligible expenses. However, the Plan sets the maximum grant that the Cypriot Government may provide an investor with at €170,850 or £CY100,000. Furthermore, the Grant Plan makes provision for cogenerated kilowatt-hours – those generated during the daytime and those generated during the night time – to be purchased by the EAC at 2.93 €cents/kWh and 2.57 €cents/kWh, respectively, with a fuel cost adjustment applicable as indicated in the Annex.

In addition, for the period 2007 – 2010, the Special Fund Management Committee for Renewable Energy Sources and Energy Savings issued a "*Grant plan for energy savings and encouraging the use of RES for natural and legal persons and for state agencies* ***not*** *performing economic activities*". Chapter DIII is devoted exclusively to the cogeneration of electricity and heat and/or cooling and states that beneficiaries of grants are school boards and charity organisations, municipalities and communities and other non-governmental organisations to the extent that they do not carry out any economic activities. Aid is granted up to 45% of the eligible budget, within the limits of the highest eligible expenses. However, the Plan sets the maximum grant that the Cypriot Government may provide an investor with at €85,425 or £CY 50,000.

The Grant Plan subsidises cogenerated kilowatt-hours – those generated during the daytime and those generated during the night time. The EAC's kilowatt-hour purchase price is subject to a fuel cost adjustment, as shown in the Annex.

The EAC's initial purchase price for electricity may be amended by virtue of a decision by the Cyprus Energy Regulatory Authority (CERA).

Moreover, in line with the Law of 2003-2006 Regulating the Electricity Market, the price paid by the EAC or any other electricity supplier to purchase electricity generated by means of high-efficiency cogeneration must be approved by CERA. This price will be adjusted on the basis of current feed-in tariffs.

In brief, the Cypriot government has incorporated all Community legislation into its own legislation, has created grant programmes on the entire budget for combined heat, cooling and power (CHCP) applications, while setting a grant ceiling which does not exceed that set by the EU's *de minimis* regime, and has subsidised cogenerated electric kilowatt-hours, providing two rates – one for the daytime and a lower rate for night-time.

Despite the efforts above, energy prices in Cyprus, combined with the absence of natural gas in the country's energy system, the absence of technical and investment expertise in CHP technology and a lack of awareness of its advantages, have led to the current situation, where, despite the existing potential, CHCP penetration in the country's energy system is virtually non-existent.

Cyprus's energy system is at a transitional stage, given that it is undergoing significant institutional and organisational changes within the scope of the deregulation of its energy markets, as is the case in most of the EU's new Member States.

The new institutional framework has brought about challenges in Cyprus's energy sector, given that it has required the incorporation of Community directives, rules and regulations primarily concerning competitiveness and the maintenance of energy production costs and of low prices for the end consumer, as well as the achievement of common European environmental objectives. However, when analysing the deregulatory course of Cyprus's energy market, it becomes evident that electricity production is still centralised, electricity selling prices are non-competitive, natural gas is entirely absent from the country's energy balance, fuel oil is still used for electricity production, and there is, furthermore, inadequate infrastructure, all of which serve to slow down the opening of energy markets.

The promotion of cogeneration (CHP) and high-efficiency cogeneration (HE-CHP) and the barriers preventing the realisation of Cyprus's national CHP potential are analysed according to the categories indicated by the European Commission within the scope of Directive 2004/8/EC, as follows:

- **Technical Barriers,** such as the country's weather conditions, connecting CHP to the Grid, etc.,
- **Economic Barriers,** such as energy prices,
- **Administrative Barriers,** such as legal matters, time-consuming licensing procedures, etc.

7.1.2 Technical Barriers

7.1.2.1 Climatic conditions in the country – The role of heat and cooling loads in the country's SMEs and tertiary sector.

Cyprus is located at a latitude of 35^{o} North and a longitude of 33^{o} East and it is surrounded by the eastern Mediterranean Sea. It is to the effects of this sea that Cyprus owes its Mediterranean climate. The main features of this climate are dry, hot summers from mid May to mid September, mild winters from mid November to mid March and the two transitional seasons, autumn and spring, in-between. In summer, Cyprus is affected by low barometric pressure centred in southwest Asia, resulting in high temperatures, and there is very little rainfall, on average not exceeding 5% of the total average annual rainfall. The total average rainfall in December, January and February corresponds to 60% of the country's annual rainfall.

Cyprus has hot summers and mild winters, but this general picture varies from region to region owing to two factors: (a) the relief, which causes the temperature to drop by approximately 5^{o}C every 1,000 metres of altitude, and (b) the effect of the sea, which causes summers to be cooler and winters to be relatively milder in coastal regions, particularly on the western coast. Annual wind temperatures range widely from around 18^{o}C in the hinterland to about 14^{o}C in coastal regions. In July and August average daily temperatures range between 29^{o}C - on the central plain - and 22^{o}C - on the highest peaks of Mt. Troodos, while average maximum temperatures during these months are 36^{o}C and 27^{o}C, respectively. In January average daily temperatures are 10^{o}C on the central plain and 3^{o}C on the highest peaks of Mt. Troodos, with average minimum temperatures of 5^{o}C and 0^{o}C, respectively.

Cyprus's climate, and particularly its two basic climatic parameters, rainfall and temperature, fluctuated significantly in the course of the 20th century. More specifically, the average annual rainfall in the first thirty years of the century was 559 mm, dropping to 462 mm in the final thirty years, i.e. by 17%. On the contrary, the average annual temperature in Cyprus – both in the cities and in the countryside – showed a rising trend, increasing by an average of 0.01 °C/year. Temperatures for the period 1976-1998 rose at an average rate of 0.035°C/year in the cities and 0.015°C/year in the countryside. In Nicosia, the average annual temperature increased by 0.8°C, from 18.9°C in the first thirty years to 19.7°C in the final thirty years of the century.

All of Cyprus's regions have a long sunshine period when compared with many other countries. In the lowlands, the average number of hours of sunshine throughout the year amounts to 75% of the hours of sunshine. In summer there is sunshine for an average of 11.5 hours a day, while in December and

January, the most overcast months, sunshine duration is reduced to 5.5 hours a day. The maximum possible duration of sunshine in Cyprus ranges from 9.8 hours a day in December to 14.5 hours a day in June.

In brief, temperatures recorded for Cyprus's external environment in the last few decades are described as mild in winter and, consequently, with low heating degree days, and as high during summer, which lasts for a long period of time and brings about high cooling degree days. As regards CHP use, Cyprus's climatic conditions understandably favour its use, particularly with regard to meeting cooling loads, especially in the tertiary sector, by means of CHP and absorption towers to meet high cooling loads. Cyprus's dynamic tourist industry in its majority offers a high level of services to guests in terms of air conditioning, hot service water, etc.
An overwhelming majority of businesses in the Cypriot industry, based on the EU definition, come under the broad definition of Small and Medium-sized Enterprises. According to the latest official data of the Statistical Service of the Republic of Cyprus, there are 6,300 industrial units employing 38,000 people. In the past, Cypriot industries evolved into a protective environment, with high import duties on foreign products, which ensured that Cypriot industries had almost complete control of the local market. Moreover, state subsidies enabled a number of industries to penetrate foreign markets. This form of state protectionism resulted in a significant number of industries becoming complacent. Very few industrial SMEs strove to upgrade their structure, administration or management and to keep up with technological developments in their field; in their majority they remained traditional family businesses, in which energy costs naturally played an almost insignificant role. Cyprus's accession to the European Union and the drastic reduction in state aid in line with the European *acquis* and the rules of the World Trade Organisation, of which Cyprus is a member, led to serious problems in the industrial sector. The industrial sector's value added in real terms rose by 0.8% in 2003, as compared with 1.3% in 2002. The largest share of value added belonged to the food product, beverage and tobacco industries, which traditionally constituted the largest sub-sector. This negative picture is mainly a result of low productivity, comparatively high labour costs, energy costs and a lack of specialised personnel. In addition, there are weaknesses in the industrial sector's administrative systems, in its energy consumption management, in its trading methods and, in some cases, in its product design. In recent years, there has been a change in the export destination of processed products, the European countries being now the target. More specifically, exports to the EU amounted to 50% of total exports in 2003, with Arab countries, which in 1982 absorbed over 62% of the country's exports, receiving only 22.6% of this total in 2003.
Today, Cyprus, which has a highly qualified work force and an advantageous geostrategic position, is striving to develop a high-technology industry or an industry manufacturing high-technology products the demand of which depends on quality rather than price. In 2008, Cyprus joined the Economic and Monetary Union, thereby creating new growth opportunities and prospects not only for the manufacturing sector but also for all economic sectors, and, particularly, the tourism industry.

Cyprus's construction sector has recorded a significant increase in the construction of different types of tertiary-sector buildings (e.g. large hotel units, shopping/exhibition centres, large office buildings, etc.) which, due to their operating hours, require heat loads and high cooling loads in order to create comfortable temperature conditions for the people visiting or working in such buildings.

It is also a known fact that for a CHP system to be financially viable, it must be in operation for at least around 3500 hours a year (350 days x 10 hours a day) and must have an adequate heat and/or cooling load. Thus, if the CHP system is only used to meet heat load demands and remains inoperative during the summer, the investment will not be viable, given that it will be operating for less than 3500 hours and with small total heat loads.

It is, therefore, reasonable that the selected CHP system must be technically suitable for meeting both heat and cooling load demands in the facility, whether it is in the industrial or tertiary sector. Such systems are called trigeneration systems, namely systems generating electric, thermal and cooling energy. Today these are widely used all over the world to meet the energy needs of industrial plants as well as tertiary-sector buildings such as hospitals, hotels, shopping centres, sports centres, etc., recently also finding use in the household sector.

Trigeneration systems have failed to penetrate the Cypriot market, mainly owing to the high purchasing and installation costs of such new and high-technology systems, the absence of natural gas as a primary fuel and the failure to adequately inform technical experts and investors about the advantages of such systems. Therefore, the Cypriot government needs to take timely action to establish favourable criteria promoting such trigeneration systems, which lead to primary energy savings, reduced emissions – compared with conventional systems – and constant conditions of thermal and cooling comfort.

7.1.2.2 Connecting CHP to the Grid

Cogenerated electricity access to the Grid is a complex problem encountered by cogenerators. The failure of the Transmission System Operator (TSO) and of the EAC to provide clear and explicit rules will soon result in CHP and HE-CHP system owners, especially those owning industrial plants, negotiating access terms with the TSO from a disadvantageous position, given the lack of experience on the part of both parties, and particularly of the TSO.

The European Union recognised the need to overcome the obstacles to CHP system connection to the electricity transmission grid and, with reference to the Directive on HE-CHP (2004/8/EC), adopted the philosophy of the corresponding Article 7 of the Directive on Renewable Energy Sources (2001/77/EC). Greater flexibility is, therefore, required in connection procedures, mechanisms and costs so as to create a clear-cut environment for the promotion of CHP systems, particularly small-scale and micro CHP systems.

There is currently no recorded experience in Cyprus on connecting CHP/HE-CHP systems to the Grid, either by investors, the TSO or the EAC. The TSO has stated that issues pertaining to the connection of CHP systems to the Grid are new to it, that it has no such experience and that its personnel needs to be trained on these issues by experienced agencies such as the European Transmission System Operators or the Greek operator (HTSO).

As regards connection costs, the TSO pointed out that while for wind energy investors connection costs are currently shared, 50% being paid by the producer and 50% by the TSO, this is not the case for cogenerators, who have to bear the entire cost themselves. However, as emphasised by the TSO, there is a willingness to change this policy and for connection costs for CHP systems to be calculated in the same way as for RES investments (50-50%).

Given how important the matter of charging a fee for CHP connection to the Grid is, there is a need for time schedules to be predetermined and accepted in advance as regards the TSO's preparation of connection reports. The TSO will, therefore, have to provide, within a short period of time, binding connection reports, mainly to owners of large CHP plants, which will include proposals for the allocation of expenses for reinforcement work.

Moreover, cogenerators who are characterised by law as "high-efficiency cogenerators" must be granted the right of access to the technical parameters of networks, so as to facilitate the installation of new-generation CHP plants in distribution networks in the best manner possible.

Lastly, CHP plants developed in the tertiary (small-scale CHP – up to 1 MW_e) and household (micro CHP – up to 50 kW_e) sectors must be provided simpler, non-discriminatory access to the electricity grid.

As regards small-scale CHP installations, which essentially replace boilers generating thermal energy and were designed so as to also meet cooling loads, it is important that the process of connecting to the Grid does not cause any delays. Consequently, a 'low' connection charge for such systems would be adequate, without requiring contributions from small-scale cogenerators for the local reinforcement of distribution networks, which will have to be borne exclusively by the TSO.

Micro CHP systems require even simpler connection rules and expenditure. In order to facilitate the work of the Grid Operator, individual micro-cogenerators must, within a reasonable period of time before installing the CHP system, notify the TSO and the EAC of their intention to connect with the grid, and must work together with their local EAC branch so as to resolve all technical issues. Technical rules for connecting micro CHP systems have already been adopted at European level and must also be directly adopted by the Cypriot state.

7.1.2.3 Priority in load allocation for CHP plants

Law 173(•)/29.12.2006 amends the Law "*Regulating the electricity market*" so as to include the new definitions of CHP and HE-CHP set in EU Directive 2004/8/EC. Moreover, Law 174(•)/29.12.2006 "*Promoting the Cogeneration of Heat and Power*" fully harmonises Cyprus's energy legislation with EU Directive 2004/8/EC.

Article 8, of Law 174(•)/29.12.2006, concerns "*Grid Issues*". In particular, paragraph 8.-(3b) states that "*priority is given to <u>power plants</u> generating up to 7 MW_e*". Moreover, it is mentioned in par. 8.-(4b) that "*in the event that an autoproducer generates electricity by means of high-efficiency cogeneration, as indicated in par. (b) of section (3), priority is given to <u>power plants</u> generating up to 11 MW_e*".

Clearly, whether seen from a technical, economic or environmental perspective, there is no reasoning behind the establishment of such limits, which are in evident contravention of the objectives and spirit of Directive 2004/8/EC. Note also that even though the Law concerns CHP, the article gives priority to

power plants as opposed to cogeneration plants. This could be due to ignorance of the particular nomenclature, but, nevertheless, it leads to misinterpretation by potential foreign and local investors.
Note that in the Commission's initial draft of the HE-CHP Directive there was a limit of 50 MW_e for priority to be given, but at the 1st meeting of experts of the EU Council of Environment Ministers in January 2003, all of the then 15 Member States questioned the need for such a limit. Moreover, the rapporteur for the HE-CHP Directive in the European Parliament proposed that the limit should be repealed on the grounds of it being restrictive and arbitrary. The final text of Directive 2004/8/EC contains no reference whatsoever to any limits applicable for priority to be given during CHP plant load allocation. It is also evident that this limit was set in the Cypriot law, based on the corresponding limits of 35 and 50 MW_e set by Greek Law 2773/99 on the deregulation of the energy market.

The 11 MW_e limit, which, as emphasised, was also set as a result of pressure being exerted by the EAC, is considered to be arbitrary and may possibly be justified by the perception that "large CHP plants have easier access to more favourable financing and to pricing of primary fuel". This is not the case, since financing support policies apply only to smaller CHP systems, while better fuel prices depend on the state of energy market deregulation in the country and in the competition. Conventional power stations are clearly cheaper than the corresponding CHP plants, owing to the fact that they are less complex. Consequently, in the absence of any additional benefit for CHP, the latter plants will always be at a disadvantage. Lastly, under normal circumstances, larger CHP units are more efficient in terms of primary fuel consumption, as compared to smaller units. This lower limit does not abide by the general principle that cogeneration plants should be designed according to the demand for **useful** heat. For example, the 11 MW_e limit set by the Law forces plants to be designed in such a way so as to comply with this limit even when the demand for heat or cooling is higher and a larger unit would be more efficient and necessary from both an economic and an environmental perspective. It should also be noted that very few CHP plants with a capacity greater than 11 MW_e will be set up in Cyprus; nevertheless, this limit is still a barrier, especially for foreign investors.

The results of comparative studies conducted at European level show that significant savings are achieved in primary fuel and CO_2 when CHP systems larger than the limit set by the Law are used, provided their dimensioning is based on **useful heat,** as, for that matter, stipulated in EU Directive 2004/8/EC.

Lastly, Directive 2004/8/EC clearly recognised the environmental benefits offered by cogeneration, particularly as regards meeting Kyoto Protocol targets. These benefits apply irrespective of installation size, both to small installations in the tertiary sector and to larger installations in the industrial sector and in district heating and cooling.
A ton of CO_2 saved by using a CHP system remains **the same**, irrespective of the size of the CHP system. Consequently, it makes no sense to restrict rewards based on environmental benefits to smaller installations only.

7.1.3 Economic Barriers

7.1.3.1. Fuel prices, cost of purchasing fuel, pricing cogenerated electricity for sale.

A major issue concerning CHP system penetration in Cyprus is pricing the primary fuel used by CHP systems. More specifically, the problem lies in the pricing of crude oil and its derivatives, given the significant global rise in crude oil prices – a common occurrence in recent months – which has affected the global economy and has also had a major impact on Cypriot economy.

Access to the crude oil market is not a problem, according to Cyprus's only large industrial cogenerator (Vassilikos Cement Works Ltd), since the large quantities it requires for its operations enable it to obtain petroleum from the free market.

Another major issue is the absence of natural gas in Cyprus, the presence of which in the country could have reduced fuel costs by 10%.
Of course, the EAC has made serious efforts to reduce fuel costs: in 2006 it increased the output of its power plants by 1% as compared to 2005, while at the same time achieving primary fuel savings of 1%, and it reduced its operating costs as well as its unbilled consumption.

Nevertheless, it also has policies that encumber the price of electricity, such as:

- A 0.13 C• cent/kWh or 0.079 €/kWh charge, effective as of 2003, that encumbers the end consumer as a so-called 'green' tax for RES development,

- The ‘indirect taxation’ charged since 2003 as the ‘dividend’ the Cypriot government is supposed to obtain from the EAC,
- VAT (15%), and
- The fact that the EAC, a semi-governmental organisation, based on a special arrangement in force since 2002, pays twice as much tax as other companies to the Cypriot government (28% instead of 10%). The Cypriot government apparently intends to pass a bill to reduce the tax in question.

A fine for generating electricity using polluting fuels will certainly be added to the cost of fuel in the near future, which means that Cyprus produces more pollution than it is entitled to do on the basis of the EU’s emissions trading system.

7.1.4 Administrative Barriers

7.1.4.1 CHP System Licensing Procedure

CHP system licensing procedures in Cyprus and in all other Member States with a low penetration of CHP systems have to date proven to be a complex and time-consuming matter for investors as well as researchers. Different public services, each with their own bureaucratic structures, are involved in the various licensing stages of a CHP or HE-CHP investment, in such complex projects, creating delays in evaluation, particularly at the initial stages. It must, however, be said that the Cypriot services involved in the licensing of CHP systems, such as CERA and the TSO, have continuously striven to simplify procedures. As a result, said procedures are currently quick.

According to CERA and from information obtained from Cyprus’s only large cogenerator, the time taken to obtain a license is not excessive. The investor must first file an application to CERA, submit a complete technical and economical survey and Environmental Impact Assessment for evaluation and pay a fee. Within the following two months, CERA must examine the application and request that the investor should supply any additional information. When CERA has certified that the file is complete, then it is required to issue an operating licence within about three (3) months, with a maximum extension of three additional months.

Besides, the TSO has to confirm that the Grid is capable of receiving the injection of cogenerated electricity. Also, for CHP systems up to 5 MW_e, the TSO requires that the cogenerator should apply to connect the CHP station to the Grid, and after the connection terms have been studied, the TSO issues the terms that the cogenerator must accept. Furthermore, based on the Law, the TSO must submit a certificate for the electricity cogenerated, in line with the spirit of Directive 2004/8/EC.

The European Commission considers CHP to be a technology that, together with RES and Energy Saving, helps the Commission achieve the targets set in the Kyoto Protocol on the reduction of gaseous pollutants causing the greenhouse effect.

In order to assist small-scale and micro CHP systems, as well as CHP systems using RES as a primary fuel, a legislative decree has been issued that simplifies the licensing procedure for such units, with the exception of the licence obtained from CERA, which solely examines and files data concerning the small (or micro) CHP system.

This is a very important point that has been introduced into Cyprus’s Law on HE-CHP and on CHP and HE-CHP penetration into the country’s energy system.

Lastly, a positive aspect is that authorisation to set up a CHP (or HE-CHP) system is granted by CERA, without the decision having to be approved by the Ministry of Energy. This is a major step towards the complete deregulation of Cyprus’s energy market.

7.1.4.2 Adaptation of Financial Aid Measures for HE-CHP

Law 174(I)/29.12.2006 and, particularly, Article 7(1-3f) thereof refers to financial aid programmes, plans and measures for CHP and HE-CHP. The Cypriot government has established two different aid programmes for CHP systems, spanning from 2007 to 2010.

For 2007, the Special Fund Management Committee for Renewable Energy Sources and Energy Saving issued a “(De minimis) *Grant plan for energy saving and encouraging the use of RES for natural and legal persons and for state agencies performing economic activities*”, in which Chapter LIII is devoted exclusively to the cogeneration of electricity and heat and/or cooling.

Thirty percent of the eligible budget is subsidised, within the limits of the highest eligible expenses. However, the Plan sets the maximum grant that the Cypriot Government may provide an investor with at €170,861 or £CY 100,000. Furthermore, the Grant Plan makes provision for the cogenerated kilowatt-hour generated during daytime to be sold at 0.02921 €/kWh (29.21 €/MWh), and the cogenerated kilowatt-hour generated during night time at 0.02563 €/kWh (25.63 €/MWh). The EAC prices above are subject to a fuel cost adjustment. Relevant fuel cost adjustments are presented in the Annex.

In addition, for the period 2007 – 2010, the Special Fund Management Committee for Renewable Energy Sources and Energy Savings issued a "*Grant plan for energy saving and encouraging the use of RES for natural and legal persons and for state agencies not performing economic activities*". Chapter DIII is devoted exclusively to the cogeneration of electricity and heat and/or cooling. As stated in this chapter, beneficiaries of grants are school boards and charity organisations, municipalities and communities and other non-governmental organisations to the extent that they do not carry out any economic activities. Aid is granted up to 45% of the eligible budget, within the limits of the highest eligible expenses. However, the Plan sets the maximum grant that the Cypriot Government may provide an investor with at €85,431 or £CY 50,000. Moreover, the Grant Plan subsidises cogenerated kilowatt-hours – those generated during day time (daytime price: 0.06527 €/kWh – the subsidy granted is calculated as follows: 0.06527 – 0.02922 = 0.03605 €/kWh or 36.05 €/MWh, with an EAC purchase price of 0.02922 €/kWh) and those generated during night time (night-time price: 0.05724 €/kWh – the subsidy granted is calculated as follows: 0.05724 – 0.02563 = 0.03161 €/kWh or 31.61 €/MWh, with an EAC purchase price of €0.02563). Relevant fuel cost adjustments are shown in the Annex.

In addition, over and above the EAC price, a subsidy will be granted to CHP electricity producers from the Special RES Fund, only for killowatt-hours channelled to the EAC's grid and depending on the CHP system in use. Should the price paid by the EAC be revised, the subsidy will be adjusted so that the overall price offered to the producer remains constant in the course of the relevant contract entered into between the producer and the EAC.

Evidently, the Cypriot government has established grant programmes on the entire budget for combined heat, cooling and power (CHCP) applications, yet setting a grant ceiling that does not exceed that set by the EU's *de minimis* regime. Furthermore, it subsidises the cogenerated electric kilowatt-hour, providing two rates – one for the daytime and a lower rate for night-time. Applying *de minimis* subsidies to CHCP is a serious barrier to CHCP development, given that such investments are capital intensive, especially when they require that cooling loads should also be met using absorption towers, which have a high purchase cost, whereas the use of such systems in Cyprus could be particularly successful, especially in the tertiary sector (hotels, hospitals, etc.) for meeting heat and cooling loads for hot service water and electricity.

As regards the pricing of CHP-generated electricity sold to the Grid, selling prices for such electricity are not particularly satisfactory given that the end consumer and national economy do not gain from the avoided cost of separate generation of conventional electric energy and heat/cooling energy, as is the case in various other European countries. Generally speaking, the central concept of distributed generation lies in avoiding ongoing investments by large power companies, where the kilowatt-hour purchase price of distributed generation producers must consequently be associated with the long-run marginal cost of production (it incorporates investment cost into production cost). At the moment, the selling price of cogenerated energy in Cyprus is a percentage of the long-run marginal cost of electricity generation.

7.1.4.3 Law 174(•)/29.12.2006 on CHP and HE-CHP

Law 174(•)/29.12.2006, which was passed in December 2006, defined high-efficiency cogeneration (HE-CHP) as "*primary energy saving of at least 10% compared with the separate production of heat and electricity*".

Article 8 on 'Grid Issues', and, in particular, par. 5 thereof, states that the Operator may "*at any moment and without restriction*" reduce HE-CHP-generated electricity transmitted to the Grid if the Operator believes that the system's operating conditions render it necessary. This paragraph is a serious barrier to the development of HE-CHP and CHP. Cypriot legislation requires that system stability should also be ensured by means of a substantiated decision from the Operator that will be approved by CERA. This barrier has been cited because law-makers have not realised one of the major advantages of CHP and HE-CHP, namely that these create conditions of total stability in the Grid. This paragraph in the Law is a sign of fear and, possibly, ignorance of the way in which CHP systems work, owing to the absence of such systems from Cyprus's energy system. Once these systems become widely used in the future, such paragraphs will remain inactive or will be removed.

Today, only HE-CHP can benefit from Law 174(•)/29.12.2006, while the entitlements of 'ordinary' CHP, i.e. CHP that does not fall within the scope of the definition of HE-CHP, remain on many points unclear. However, a method for calculating HE-CHP under Directive 2004/8/EC has yet to be adopted at European level. This means that no cogenerator is able to prove that they are high-efficiency cogenerators so as to be entitled to the benefits. It is, therefore, likely that the TSO (or EAC) will not accept a CHP system's characterisation as HE-CHP and will not grant the price set by the Law. This obstacle can be overcome through a directive by the Minister for Commerce, Industry and Tourism accepting the methodology stipulated in EU Directive 2004/8/EC, using reference prices accepted by the Commission and officially announced by the end of 2006. This directive will be in force until the accepted methodology is officially announced by the European Commission.

7.1.5 Lack of internalisation of external costs in energy prices

This issue, concerning the environmental and social cost of energy, is of particular importance throughout Europe, but is, nevertheless, not dealt with in Cyprus's current legislation. Internalisation of external costs of energy prices will highlight the significance of CHP systems and their environmental advantages when compared with the conventional method of generating electricity and heat.

7.1.6 Other Barriers

Other barriers affecting the promotion and utilisation of CHP are:

- The Cypriot market's lack of energy service companies (ESCOs), which could more effectively promote certain CHP applications. The country's harmonisation with Directive 2006/32/EC is expected to assist in this matter;
- The Cypriot government's failure to establish Third-Party Financing (TPF), which has also had an impact on CHP promotion;
- The absence of real standby tariffs that would encourage autoproduction;
- The immature market, given that there are very few installations, causing investors to mistrust CHP investments;
- Technical experts' ignorance of CHCP and HE-CHP systems, which has resulted in the absence of any serious attempt to make CHP advantages known to potential investors, such as hotel owners, shopping centre managers, etc.

7.2 Proposed Support Measures for HE-CHP

The analyses in Chapters 5, 6 and 7.1 lead to the determination of policy measures that will support HE-CHP in Cyprus, as regards the implementation of specific quantitative targets to serve as policy goals for HE-CHP.

7.2.1 Connecting to the Grid

The TSO and EAC's failure to provide clear and explicit rules will soon result in CHP and HE-CHP system owners, especially those owning industrial plants, negotiating access terms with the TSO from a disadvantageous position, given the lack of experience on the part of both parties, and, particularly, of the TSO. The following measures are proposed:

1. The connection cost for HE-CHP systems should be calculated in the same way as for RES investments (50-50%);
2. The TSO should provide, within a short period of time, binding connection reports, mainly to owners of large HE-CHP plants, who will include proposals for the allocation of expenses for reinforcement work;
3. HE-CHP plants developed in the tertiary (small-scale HE-CHP – up to 1 MW_e) and household (micro CHP – up to 50 kW_e) sectors must be provided simpler, non-discriminatory access to the electricity grid. Simple rules should be established for micro-cogenerators to connect to the Grid, and the rules provided by the EAC should be clear and unambiguous. The rules stipulated in prEN50438 "Requirements for the connection of micro-generators in parallel with public low-voltage distribution networks" should, in effect, be followed;
4. TSO personnel should be trained on these issues by experienced agencies such as the European Transmission System Operators or the Greek operator (HTSO).

7.2.2 Priority during load allocation

The 11 MWe limit under Law 174(•)/29.12.2006 should be repealed, following consultation with the EAC, since it is in obvious contravention of the objectives and spirit of Directive 2004/8/EC. A limit of at least 30 MWe should be set. The 30 MW limit was concluded after analysing case studies, based on which no HE-CHP plants are expected to exceed this limit in the immediate future.

7.2.3 Financial Support Measures

The economic potential for HE-CHP is variable and depends mainly on fuel price trends and on energy policy measures and economic tools for HE-CHP. Examples of trends in economic potential are shown in Tables 7.3.1 and 7.3.2. More specifically, Table 7.3.1 shows economic potential from the perspective of the national economy, with an estimate of the HE-CHP penetration level that will be advantageous for the national economy, while Table 7.3.2 provides a parametric analysis to determine a financially viable penetration level for investors assuming different levels of financial support. The desired HE-CHP potential in current circumstances depends on Cyprus's National Energy Plan and the packages that will help to meet environmental goals and energy saving goals, especially within the scope of Directive 2006/32/EC. A realistic goal would be for current energy policy measures to strive for a HE-CHP economic potential of 180-200 MWe.
This potential will drop significantly as fuel prices rise and in such cases the feed-in tariff will have to be increased accordingly.

Financial support will only be provided for high-efficiency cogeneration systems as these are defined in Directive 2004/8/EC. In addition, and on the basis of Article 3 b), c) and d), high-efficiency cogeneration systems should be dimensioned so as to operate in a heat-match mode, where the adequate heat load met together with the cogenerated electricity will provide economic justification for each investment. Only such investments should be granted capital subsidies and feed-in tariffs. The subsidy threshold should be set to allow for a payback period of less than 8 years. Thus, given that systems mainly generating electricity and heat separately are not cogeneration systems in the sense of the European Directive, they will not be granted financial support. **It is proposed that financial support measures should apply to HE-CHP plants with an upper power limit of 30 MWe** given that larger HE-CHP plants are not expected to be built based on the calculations of this study. Naturally, it is within the jurisdiction of EU Member States to abolish such limits.

Capital subsidy. The analysis conducted has shown that large HE-CHP systems, and, particularly, those in industry, are less sensitive to changes in capital subsidies, fuel prices and the selling price of electricity. The same cannot be said for small HE-CHP systems in industry and even less so those in the tertiary sector, which need capital subsidies, particularly so as to be able to cope with any fuel price increases. Based on the analysis in Chapter 5, and in order to increase the sustainability of such systems, small-scale systems and micro-systems in industry should be granted a 20% capital subsidy and those in the tertiary sector a 30% capital subsidy. Such subsidisation will create a 40 MWe potential in tertiary sector buildings.

The feed-in tariffs of high-efficiency cogenerators should, at the very least, be set at the level of the electricity system's short-run marginal production cost. The feed-in tariff of high-efficiency cogenerators will be adjusted based on the revaluations of the short-run marginal cost of electricity generation, which is directly linked to international fuel prices, the cost of gaseous pollutant emissions (from 2013 onwards) and to trends in the investment cost of electricity generation technologies. Based on current prices, the feed-in tariff should be 110 €/MWh, so as to ensure an economic potential of 190 MWe, as shown in Table 7.3.1. Note that said selling price for electricity is lower than its purchase price.

Tax exemption. Table 7.3.1 has indicated that an increase in the economic potential of HE-CHP is strongly linked to a decrease in the price of fuel. Thus, tax deductions on CHP fuel and the introduction of natural gas can play an important role in ensuring a high economic potential for HE-CHP.

7.2.4 In brief: Proposed support measures for HE-CHP plants

For HE-CHP systems in industry and in general HE-CHP systems with an electrical capacity exceeding 1 MWe

1. Financial support measures should apply to HE-CHP plants with an upper power limit of 30 MWe;
2. Favourable prices should be established for primary fuel used in HE-CHP systems, also complying with provisions in European Directive 2003/96/EC on taxation of energy products and electricity;
3. Favourable selling prices should be established for cogenerated electricity sold to the Grid by HE-CHP units, based on a sliding scale of rates depending on when the electricity is injected into the Grid. Higher prices should mainly be set for the summer season (15/04 – 15/09) and, particularly, during peak hours (11:00–17:00). This price should be linked to the short-run marginal cost of generating electricity during these periods of time;
4. Connection costs for CHP systems should be calculated in the same manner as for RES investments (50-50%);
5. The TSO should provide, within a short period of time, binding connection reports, mainly to owners of large CHP plants, who will include proposals for the allocation of expenses for reinforcement work.

Small-scale and micro HE-CHP systems (tertiary sector systems with an electrical capacity below 1 MWe) and tertiary sector systems, in general, need more financial support, as shown in the analysis in Chapter 5 and in Tables 7.3.1 and 7.3.2. When fuel prices are high, these systems have zero economic potential unless they receive very high financial support (capital subsidies and FIT). The following measures are, consequently, proposed for small-scale CHP and micro-CHP systems (with less than 1 MWe in electrical capacity):

1. A 20% capital subsidy for HE-CHP in industry and 30% for HE-CHP in tertiary sector buildings. Small systems in any other sectors should be subsidised by 30%;
2. VAT exemption for micro HE-CHP units (up to 50 kWe), particularly when they are also used for trigeneration in the household and tertiary sector;
3. A 10-unit cut in VAT for small-scale HE-CHP systems (up to 1 MWe), particularly when they are also used for trigeneration in the household and tertiary sector;
4. Favourable prices for primary fuel used in HE-CHP systems, particularly when they are used for trigeneration or for more than 6,500 hours a year, and in compliance with provisions in European Directive 2003/96/EC on taxation of energy products and electricity;
5. Exemption from the licensing procedure for compact-type micro-HE-CHP and small-scale HE-CHP units, provided they have received one-off certification from the Ministry of Energy;
6. Exemption from the obligation to submit an Environmental Impact Assessment for compact-type micro-HE-CHP and small-scale HE-CHP units, provided they have received one-off certification from the Ministry of Energy;
7. Favourable selling prices for cogenerated electricity sold to the Grid by HE-CHP units, based on a sliding scale of rates depending on when the electricity is injected into the Grid. Higher prices should mainly be set for the summer season (15/04 – 15/09) and, particularly, during peak hours (11:00–17:00). This price should be linked to the short-run marginal cost of generating electricity during these periods of time;
8. Small HE-CHP plants (small-scale HE-CHP – up to 1 MW_e, and micro CHP – up to 50 kW_e) must be provided simpler, non-discriminatory access to the electricity grid. Simple rules should be established for micro-cogenerators to connect to the Grid, and the rules provided by the EAC should be clear and non-ambiguous. The rules stipulated in prEN50438 “Requirements for the connection of micro-generators in parallel with public low-voltage distribution networks” should, in effect, be followed.

7.2.5 Assessment of HE-CHP investments

Generally speaking, high-efficiency cogeneration systems should be dimensioned so as to operate in a heat-match mode, i.e. they should be designed so that they may be financially viable when meeting substantial heat loads. This should be a decisive factor in the assessment of HE-CHP investment applications for subsidies, where any systems practically operating as generators in the absence of heat loads will not be granted any financing. Note at this point that small-scale CHP and micro-CHP systems can be considered to be HE-CHP systems and, consequently, be granted financial support only if they meet an economically justified heat demand according to Article 3 b), c) and d) of Directive 2004/8/EC. Furthermore, for capital subsidy applications, it should be established that financing will only be granted to systems dimensioned to operate in a heat-match mode, with a discounted payback period of, at most, 8 years, implying a minimum accepted number of hours of cogeneration as defined in Directive 2004/8/EC.

Lastly, a system guaranteeing the origin of cogenerated electricity should be set in place. Based on European experience, such guarantees are usually provided by the competent ministries.

New Economic Tools

1. Creation of energy service companies (ESCOs) in the Cypriot market; these could more effectively promote certain CHP applications. The country's harmonisation with Directive 2006/32/EC is expected to assist in this matter.
2. The Cypriot government's establishment of Third-Party Financing (TPF) will also have an impact on CHP promotion.

7.3 National Strategy for CHP – ACTION PLAN

7.3.1. Integrated Support Programme for CHP

An integrated programme for CHP must focus on solving the basic requirements for securing investors' legislative rights, primarily through financing and incentives, and on two other basic problems that must be dealt with:

- the difficulty of establishing specific policies for cogeneration when various state agencies are involved and when more general policies on the energy sector are being shaped;
- the state's overall difficulty in implementing integrated programmes and composite policies with specific goals.

A programme must, therefore, be created that will not only contain policy measures, but also the appropriate accompanying support measures for implementing the policy. Such a programme must contain quantitative penetration targets for the short, medium and long term, as well as targeted actions that will remove barriers obstructing CHP penetration and will enable penetration at planned quantitative levels. It must also contain actions to update competent agencies and promotion and dissemination actions for investors and the public, so as to determine the actual extent of problems arising.

7.3.2. Short-Term Prospects for CHP Penetration

In brief, the short-term prospects for CHP penetration must focus on the following areas:

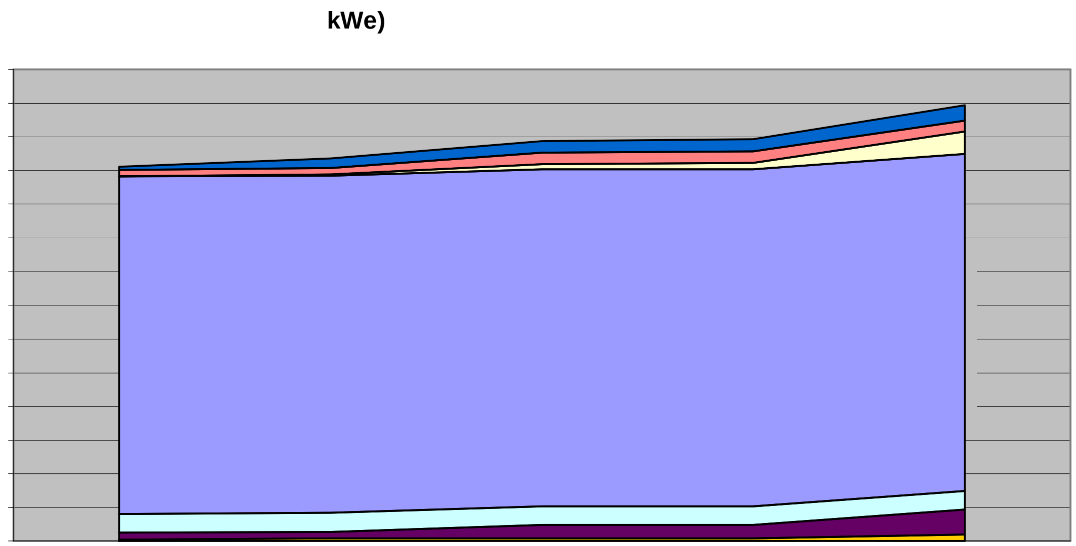
- Further penetration of CHP in industry
- Development of trigeneration in the tertiary sector, and more specifically:
  - Management of the heating/cooling potential using CHP in the hotel sector
  - CHP penetration in large hospitals
  - Management of the heating/cooling potential using CHP in very large office buildings

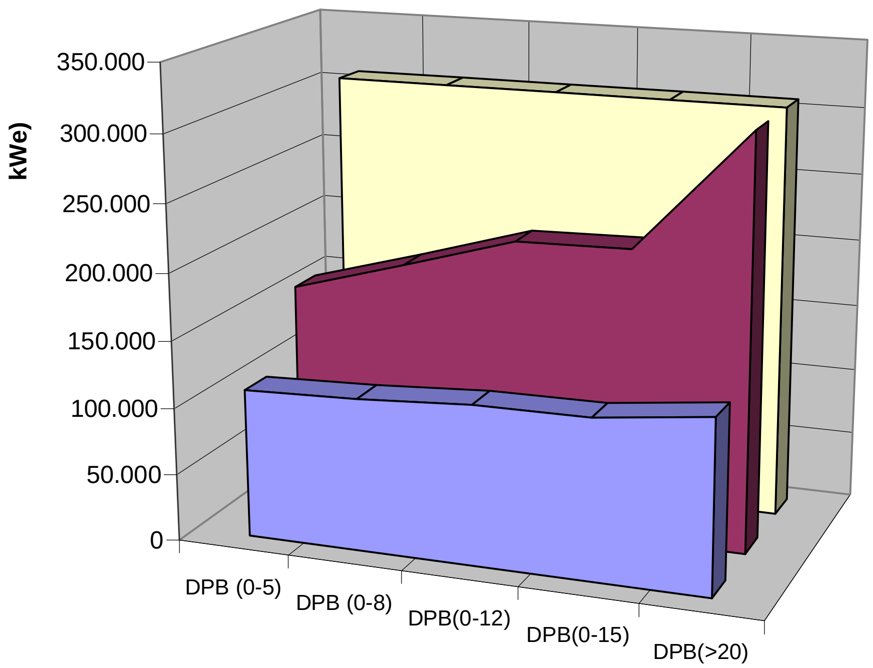
7.3.3. Mid- and Long-Term Prospects for Penetration

Mid- and long-term prospects include the penetration of small-scale CHP and micro-CHP systems, particularly in the tertiary sector, in which such systems in Cyprus must meet heat and cooling load demands owing to local weather conditions.

It is, therefore, evident that a number of problems will arise, which will essentially constitute the installation initiation stage of such systems in the Cypriot market. There is also the opportunity to change the interconnected and non-interconnected energy system by introducing more rational energy production and better load management. The gradual improvement expected in absorption chiller efficiency will significantly aid trigeneration system penetration. With this in mind, the possibility of developing, in the mid term, district heating and cooling investments near Dekeleia and Moni power stations should be investigated.

Table 7.3.1 Parametric Analysis of Economic Potential for High-Efficiency Cogeneration in all Sectors – HE-CHP Potential from the Investor's Perspective




kWe)
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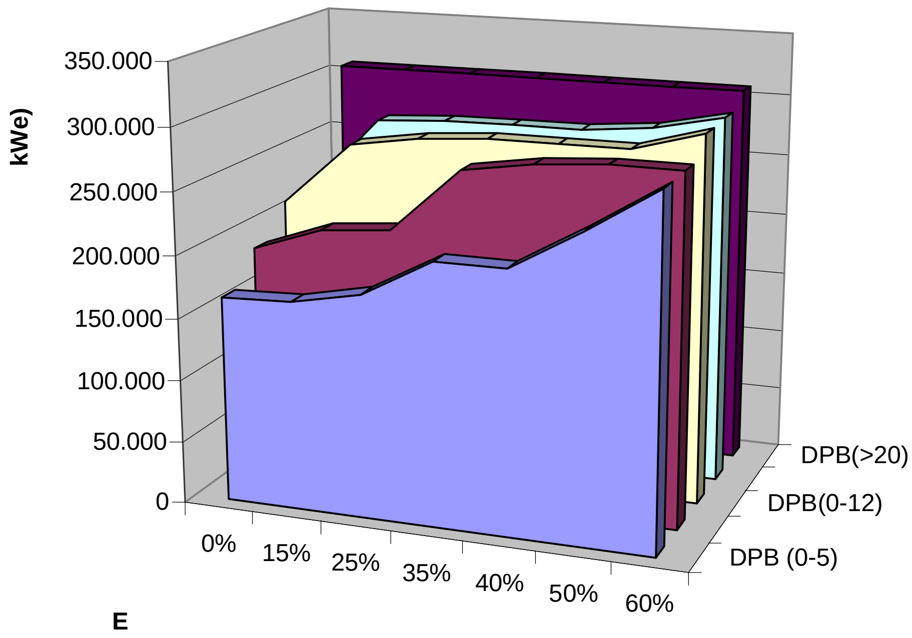
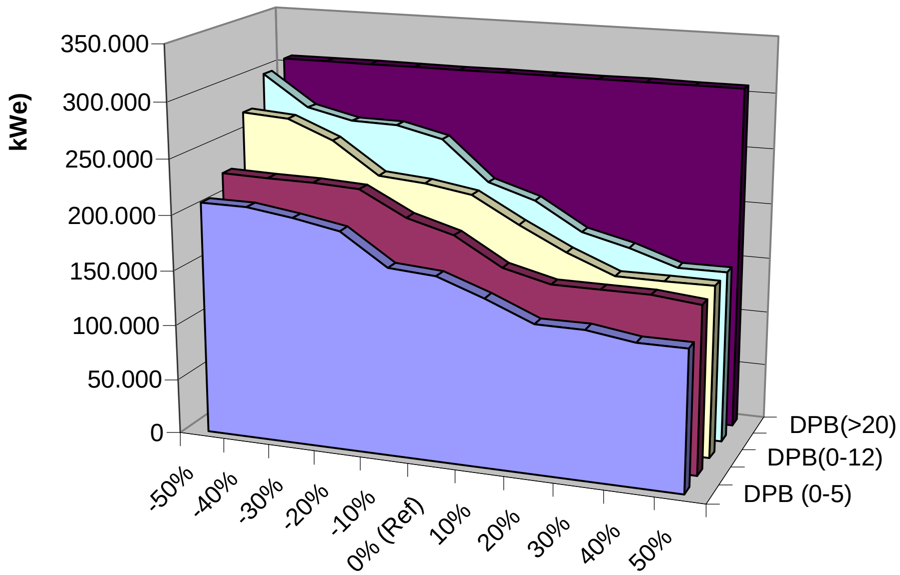
250.000
200.000
150.000
100.000
50.000
0
DPB (0-5)
DPB (0-8)
DPB(0-12)
DPB(0-15)
DPB(>20)


kWe)
350.000
300.000
250.000
200.000
150.000
100.000
50.000
0
0%
15%
25%
35%
40%
50%
60%
E
DPB(>20)
DPB(0-12)
DPB (0-5)


kWe)
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200.000
150.000
100.000
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-50%
-40%
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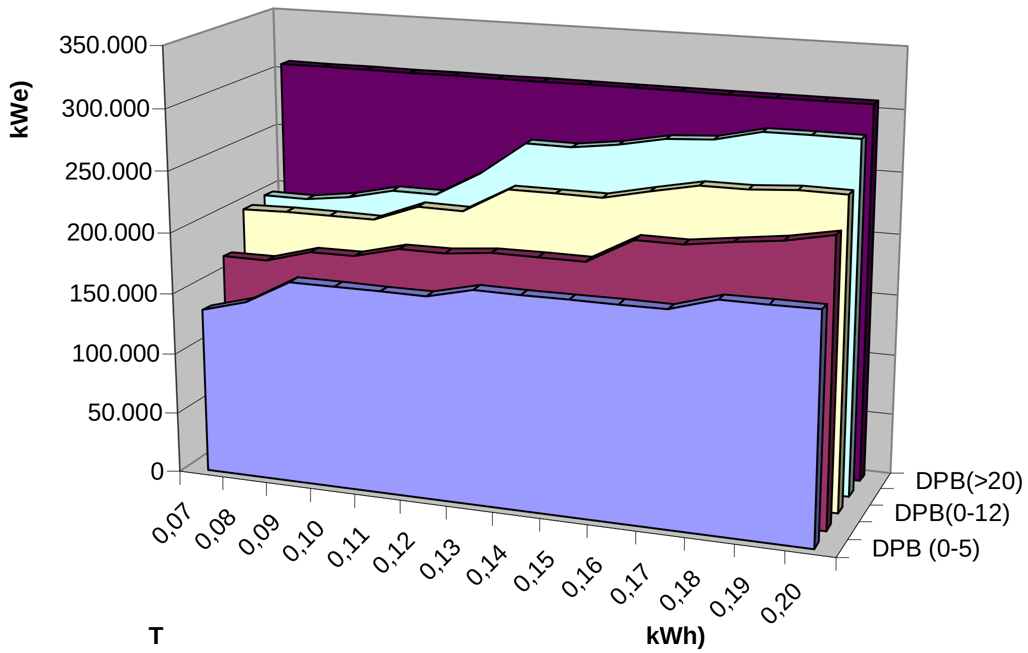
DPB(>20)
DPB(0-12)
DPB (0-5)


kWe)
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T
kWh)
DPB(>20)
DPB(0-12)
DPB (0-5)

Economic Potential for High-Efficiency Cogeneration, excluding Industry and Tertiary Sector

BIOMASS - BIOGAS	20 MWe
Solid Biomass	10 MWe
Biogas	10 MWe

DISTRICT HEATING AND COOLING	60 MWth

Economic Potential of Micro-HE-CHP Systems

Based on the small systems studied in Chapter 5, CHP systems in the household sector do not appear to be financially viable even for trigeneration purposes, because of the small duration of heat loads. Generally speaking, small HE-CHP systems are financially viable only in large tertiary-sector buildings.

Table 7.3.2 HE-CHP penetration in Cyprus – CHP economic potential from the perspective of the national economy, based on international trends in average fuel prices

Activity Type	Electricity – Installed Capacity (MWe)			Heat – Installed Capacity (MWth)		
	2010	2015	2020	2010	2015	2020
Hotels	3.5	11.3	27.9	5.4	17.2	42.5
Hospitals	0.3	1.0	3.2	0.6	1.8	5.7
Office Buildings and Shopping Centres	0.7	2.1	4.0	1.1	3.4	6.5
Tertiary Sector Total	4.5	14.4	35.0	7.0	22.4	54.7
Food Products, Beverages and Tobacco	4.4	14.2	29.8	9.0	28.7	60.1
Non-metallic mineral products	2.3	50.4	100.9	5.1	111.0	222.0
Non-ferrous metals	0.1	9.9	22.0	0.2	21.8	48.4
Industry Total	6.8	74.5	152.6	14.2	161.4	330.4
Agriculture – Animal production	5.5	17.8	20.2	9.6	30.6	34.8
Biogas	4.0	12.8	14.6	6.8	21.8	24.7
Waste treatment and landfill sites	1.5	4.9	5.6	2.6	8.3	9.5
Total	22.4	124.4	228.0	40.2	244.6	454.2

7.3.4. Informing and Coordinating Competent Agencies

The agencies responsible for ensuring CHP penetration and development are primarily the Ministry of Commerce, the EAC, CERA and the TSO, as is also the private sector of the economy in terms of prospective consumers and companies supporting construction, installation, trading and maintenance of CHP machinery.

From the perspective of the private sector, more competitive and economically advantageous solutions need to be adopted. Cogeneration is, thus, expected to be viewed favourably in cases where reasonable capital payback periods are achieved and competitiveness problems are solved. In addition, companies with a special interest in installing cogeneration units are in a position to obtain necessary technical, financial and operational support so as to solve any problems faced by prospective investors.

In order to ensure the implementation of a robust CHP policy, the Ministry of Commerce, as the presiding authority for energy, must take the initiative to inform all stakeholders about CHP problems related to their duties and to coordinate them so as to implement a CHP policy support programme. This must be done through organising a series of meetings between competent agencies and investors, so that the problems faced by both sides may be recognised and so that a joint effort may be made to resolve them.

7.3.5. Promotion and Dissemination aimed at Potential Investors

As a rule, promotion and dissemination activities are the cornerstone of any coordinated intervention in the energy sphere. In order to increase interest in Combined Heat and Power, intensive and specialised information must be provided to prospective investors so as to convince them of the technical feasibility and financial viability of such investment plans, and also to inform them about general parameters related to trends in the institutional and legislative sectors, to current financing opportunities, and so on.

Thus, to the extent that a National Action Plan must, above all, be action-oriented (focusing on actions to be launched immediately and also on actions realisable in the long term), a comprehensive programme should be immediately developed, targeting different categories of prospective investors, with a basic core common for all categories and specialised branches adapted to individual needs. The programme would aim to be:

1. Informative, in the sense that it must provide integrated information to prospective investors on technical, technological, economic, financial, procedural, institutional and legislative issues;
2. Supportive, in the sense that it must foresee the availability of specialised workforce necessary to provide real support to interested investors, and especially to SMEs in the secondary and tertiary sectors, throughout the development of their investment projects;
3. Communicative, in the sense that it must make use of appropriate communication tools to overcome any unfavourable perceptions on the part of potential investors, such as:
    - that cogeneration only concerns very large energy-consuming plants, that the procedures for developing and completing an investment plan are convoluted, time-consuming and unclear;
    - that the legislative and institutional framework governing cogeneration in Cyprus is inadequate and anachronistic and an obstacle for serious investors;
    - that the state only supports cogeneration in theory, while in practice it is only interested in protecting the monopoly interests of public utilities, etc.

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HE-CHP: HIGH-EFFICIENCY COGENERATION (COMBINED HEAT AND POWER)
CHP: COMBINED HEAT AND POWER
CERA: CYPRUS ENERGY REGULATORY AUTHORITY
TSO: TRANSMISSION SYSTEM OPERATOR
EAC: ELECTRICITY AUTHORITY OF CYPRUS
RES: RENEWABLE ENERGY SOURCES
PES: PRIMARY ENERGY SAVING

ANNEX – Fuel Prices

FUEL PRICES
(€ / 1000 LITRES)

	Jan.-07	Feb.-07	Mar.-07	Apr.-07	May-07	Jun.-07	Jul.-07	Aug.-07	Sept.-07	Oct.-07	Nov.-07	Dec.-07	2007 Average
Heating diesel	**742**	**732**	**747**	**775**	**783**	**783**	**814**	**831**	**836**	**824**	**826**	**751**	**787.00**
LPG	828	833	841	840	855	855	869	879	891	946	997	1019	**887.75**
LFO	376	369	373	393	436	441	458	487	487	491	530	569	**450.83**
HFO	282	282	282	282	282	282	327	327	327	332	383	394	**315.19**
Agricultural oil	518	506	523	551	559	559	586	605	610	629	681	699	**585.50**

OLIVE CAKE (€/TON)	34.17
PET COKE (**USD**/TON)	80 - 110
PET COKE (**€/TON**)	58.6-80.6

FUEL PRICE FOR CALCULATING FUEL COST ADJUSTMENT (€/TON)

10-12/2007	289.2833
08-10/2007	271.8385
06-08/2007	240.4857
04-06/2007	214.1732
02-04/2007	205.1176
12/06-02/2007	223.8268

	1995	2000	2001	2002	2003	2004	2005	2006	2007	2007+VAT+RES duty
AVERAGE PRICE OF ELECTRICITY (€cents per kWh)	**7.84**	**10.32**	**9.89**	**9.65**	**10.20**	**9.88**	**10.99**	**12.40**	**12.71**	**14.621**
Household	7.31	9.77	9.62	9.29	9.88	9.70	10.75	12.49	12.75	**14.660**
Commercial	8.90	11.48	10.82	10.64	11.14	10.47	11.84	13.00	13.33	**15.328**
Industrial	7.24	9.21	8.71	8.51	9.19	8.53	9.88	11.11	11.46	**13.187**
Farming	5.67	9.24	8.83	8.78	9.00	8.65	10.01	11.43	11.67	**13.422**
Street Lighting	6.54	9.02	8.78	8.51	8.77	8.44	9.36	10.99	11.23	**12.912**

Electricity prices above are mean prices that include all charges (excluding VAT and **RES Duty=0.22 €cents**)