Smart Power Generation – District heating solutions

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Executive summary

The purpose of this white paper is to give an overview of district heating systems in general, and to compare mid-range gas fired combined heat and power (CHP) solutions.

In many existing district heating systems, there is considerable potential for modernising the generating capacity and improving the efficiency of the entire system. This paper will discuss different CHP solutions and their suitability for use in current and future district heating networks. The new challenges that CHP plants need to address are emerging primarily from the increasing price volatility of the electricity markets, and from the generation variability resulting from increasing shares of intermittent renewable power generation capacity, such as wind and solar power.

CHP solutions, which are capable of high efficiency and flexible operation over a wide load range, will be more able to respond to electricity price variations, and to support intermittent, variable generation. Such plants will obtain more power dispatch, and consequently more earnings, during peak and high price hours as well as during low heat load seasons. Flexibility can be further improved with heat storage.

This paper evaluates three different CHP plants, two combined cycle gas turbine plant alternatives, and one combustion engine plant, in a typical district heating application. The key findings from the comparison are:

- Heat storage improves the system's flexibility, enabling optimal electricity and heat production
- High efficiency with a high power-to heat ratio enables more electricity production during the winter season
- Multiple units with fast starts and ramp rates enable dynamic operation during low heat demand seasons
- High power-to-heat ratio enables a wider operating range at the unit level
- Multiple units enable a wider load range at plant level, thus providing flexible operation during intermediate and low heat demand seasons
- Wide heat load range enables equivalent heat and electricity production with smaller sized plants
- A plant with multiple independent units and slightly lower electrical efficiency can be a more profitable investment under current, and particularly the emerging, market conditions

Introduction

The market landscape for combined heat and power (CHP) plants in district heating applications is changing. In many markets, there is major potential for modernising the generation capacity and for improving the efficiency of the entire district heating system. The challenges that CHP plants and production are facing are primarily a result of changes in electricity production and market conditions. The anticipated strong growth in intermittent renewable power, such as wind and solar, will bring challenges for entire power systems, and will consequently lead to considerable electricity price variations. Thus, to ensure optimum economic performance, the operation of CHP plants needs to be more flexible in the future. A typical situation in future power systems could be that, when wind generation peaks, there will be excess electricity on the market and consequently lower electricity prices. This would reduce the earnings of CHP plants from the electricity markets. The ability to store heat, while running during high price hours, and to cut back to very low plant output – or even stopping the plant - during the low electricity price hours, would increase the earnings of the CHP plant.

By questioning the traditional ways of building CHP plants, and by choosing the optimal technical solution, the financial returns can be improved. CHP plants can further increase dispatch and earnings if, in addition to selling electricity, they have the capability for participating in the emerging ancillary services and dynamic capacity markets.

In this paper the future outlook for district heating, which is emerging from the European Commission targets declared in the Energy 2020 and Energy Roadmap 2050, will be described.

The focus of this paper is on the technical economic aspects of natural gas fired combined heat and power technologies.

District heating

Heat distribution systems for residential and commercial consumers are widely utilised in Northern and Eastern Europe, as well as in major cities in Canada, the USA, Northern China, Japan and South Korea.

District heating networks have been built in cities and urban areas of very different sizes, in places where there is a dense accumulation of buildings. In many cases one common system covers entire large cities, but several local systems, covering local load points within a single city, also exist. Most existing systems are based on hot (110–170 °C) or warm (90–100 °C) water. Systems using low pressure steam are also used to some extent, e.g. in New York. The system designs are still today country specific, feeding and pumping hot or warm water to consumers and receiving cold water in return. The hot or warm water feed in temperatures are typically adjusted according to the ambient temperature.

Future heat distribution systems will be able to adapt to the market by utilising excess electricity from intermittent renewable generation at times when it would otherwise be curtailed, e.g. during high wind and low electricity demand periods. By making electricity and heat generation partially independent through the introduction of heat storage, the plant will be more flexible and able to be used more efficiently.

Heat is typically generated either in heat-only boilers or in combined heat and power (CHP) back pressure or extraction plants, which typically utilise fossil fuels, and to some extent also biomass.

Traditionally, district heat has been produced in large centralised coal or oil fired thermal plants. Today, there is also a significant number of natural gas fired combined cycle gas turbine plants in CHP applications. In smaller networks, combustion engine based CHP plants are also commonly used.

Most CHP based district heating systems are operated according to heat demand and the simultaneously generated electricity has been regarded as a by-product to be sold to the grid or consumed in the city. Consequently, CHP plants are typically operated only during the cold seasons. In the summer the heat load is typically below the minimum load of the CHP plant, and electricity prices are lower than in the winter.

Combined heat and power production is today politically desirable, both from the energy efficiency and environmental points of view. District heating systems can reach very high total efficiencies, and in optimally designed systems can be up to 90%. District heating networks are also significant assets for reducing greenhouse gas emissions when old, inefficient, heat-only boilers are replaced with modern CHP plants.

In many regions, investment feasibility is questionable since the heat market is regulated, i.e. heat prices are not based on market forces. To make CHP plants profitable in such markets, they should be able to access maximum earnings from the electricity markets, as well as from the emerging dynamic capacity and ancillary markets.

The district heating load is generally scattered over a wide area with many smaller load points. System optimisation is thus challenging and requires the simultaneous engineering of CHP plants, the district heating network, and the load centres. As a common rule of thumb, the economically optimal CHP plant size is about 40-50% of the annual peak heat load.

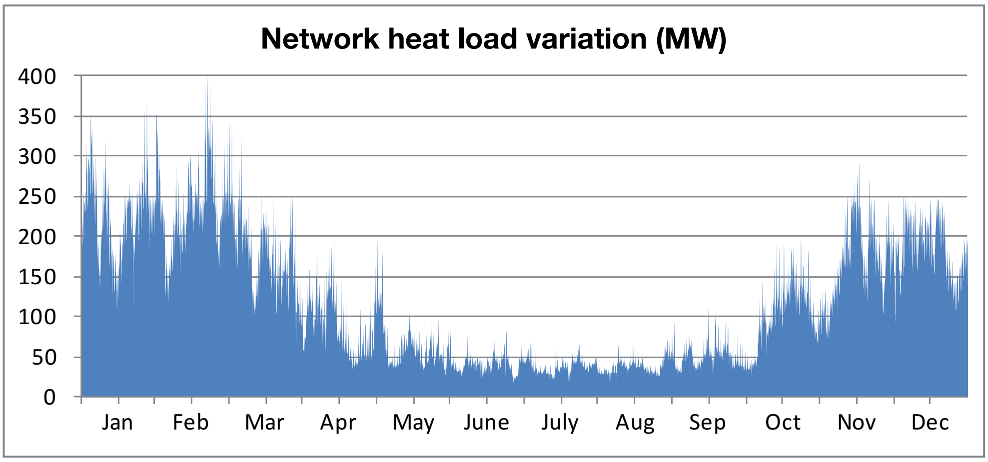


Figure 1: Load variation curve of a typical 400 MW_{th} district heating system. The network heat load varies dynamically with the ambient temperatures in the city or town. The heat load is high during the cold seasons of the year, in winter, and reaches maximum usually in mid February. Correspondingly the heat load is low during the warm season, in summer.

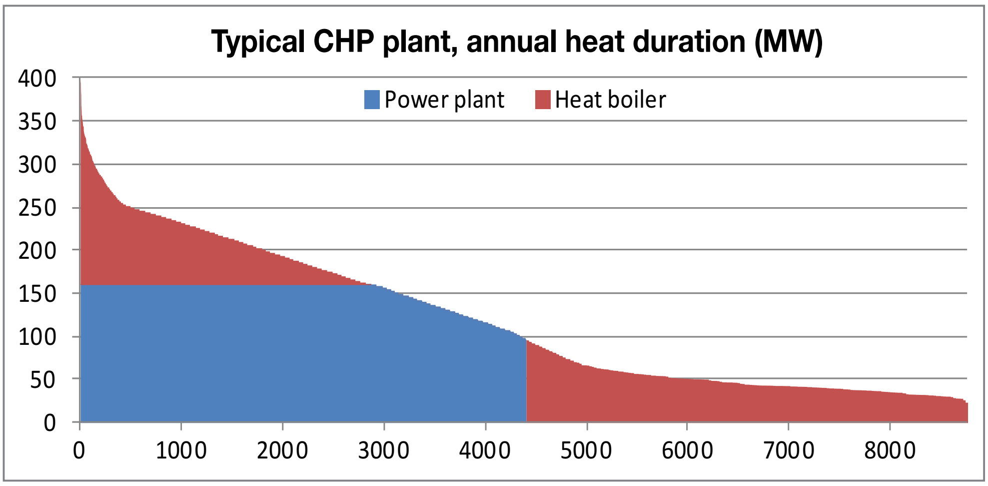


Figure 2: The load variation curve in Figure 1 is converted to a corresponding load duration curve indicating the economically optimal CHP plant size (blue colour). In this configuration, the rest of the heat demand is covered by heat boiler(s) (red colour). Figures 1 and 2 illustrate typical 400 MW_{th} district heating system properties – this system is used in the feasibility comparison in this paper. This district heating system size corresponds to that of a Central European city with a population of approximately 300,000 people.

Opportunities and challenges

The recently published EU Energy strategy 2020 and Energy roadmap 2050 focus on the utilisation of renewable energy and the efficient use of primary fuels. District heating and co-generation have important roles to play in this development, and the roadmap foresees a strong growth in CHP.

There is major potential to improve energy efficiency through increased CHP production in many district heating networks. A good example is Poland, where many projects are aimed at substituting coal, oil, and gas fired boiler plants with modern, efficient CHP plants. As a matter of fact, the biggest energy saving potential remains within the energy sector itself, where CHP will play an important role. District heating CHP is generally perceived as being positive, and several national incentive schemes exist.

Decisions to invest in new CHP capacity for district heating applications require good and reliable forecasts of future heat loads and prices, and of the potential income from electricity, as well as a stable regulatory framework. A CHP plant has a lifetime of more than 20 years, and the market conditions may change considerably during such a long time period.

Several aspects impact the optimal choice of technology when designing new CHP plants. These will be discussed in the following chapters:

Heat:

In most areas where district heating systems are in use, heat load variations between seasons are significant. Typically the heat load is low during summer, while often during autumn and spring the heat demand varies heavily. In wintertime, there are very high short term heat demand peaks and a higher base load. In many places, there are notable year to year average temperature variations that make district heating plant size optimisation even more challenging.

The improved insulation of heat consumers, such as buildings, generally leads to a decrease in heat demand. In Gothenburg, Sweden, for example, the system operator estimates an annual heat demand decrease of 1-3%. On the other hand, most district heating systems are growing as new heat consumers are connected. Studies in the Netherlands also show that behavioural changes can increase heat demand due to higher consumer comfort, such as longer showers and baths.

Electricity:

Most electricity markets, e.g. in Europe, have been opened for competition. This has resulted in increasing price volatility. Plant electricity dispatch is based on market price signals. Additionally, increasing shares of variable renewable power generation, such as wind and solar power, tend to increase electricity price variations. A challenge for CHP plants is that the heat load and electricity price do not always correlate. An ability to make the CHP plant's heat and electricity production at least partially independent will, therefore, increase its profitability. A possible solution is to connect a buffer / heat accumulator to the CHP plant or district heating system. The benefits of this solution will be discussed later in this paper.

In today's deregulated electricity markets, electricity can no longer be seen only as a secondary product for CHP installations. The CHP plant operation profile and plant concept need to enable operation according to electricity prices, and thus maximise income from electricity markets. In some markets, promoted merit orders of CHP plants, which would improve their feasibility, are being discussed. This aspect is, however, not considered in the feasibility evaluation in this paper

CHP bonus

Some countries apply CHP bonus electrical tariffs, which aim to achieve the efficient use of fuels and which typically reward high annual total efficiency. CHP plants can get an additional subsidy on top of the electricity tariff, based on the amount of produced electricity (MWh), when also producing heat. Normally the CHP bonus is based on the annual total efficiency – i.e. the higher the efficiency, the higher the bonus. Additional bonuses are in some countries available for CHP production utilising renewable fuels.

Improved flexibility with district heating storage

The supplementing of a CHP plant with a district heating storage system or heat accumulator enables the operation of a CHP plant to be more efficient and flexible. Heat accumulators are normally atmospheric hot water based vessels, dimensioned according to the size and needs of the district heating network. The accumulators are ideal in systems with strongly varying electricity prices, e.g. due to variations in demand during night and day and with a high penetration of intermittent renewable generation. The plant can run on full power when electricity prices are high, and simultaneously charge the district heat storage. The heat can be discharged from the storage when lower electricity prices make operation of the CHP plant unattractive. Similarly, a fast dispatching CHP plant can be operated to balance variations in the production of renewable power. In wind power intensive systems, where electricity prices might even turn negative, e.g. during nights with high wind speed, and there is overproduction in the electrical system, electric boilers can be an excellent complement to charge the heat accumulator.

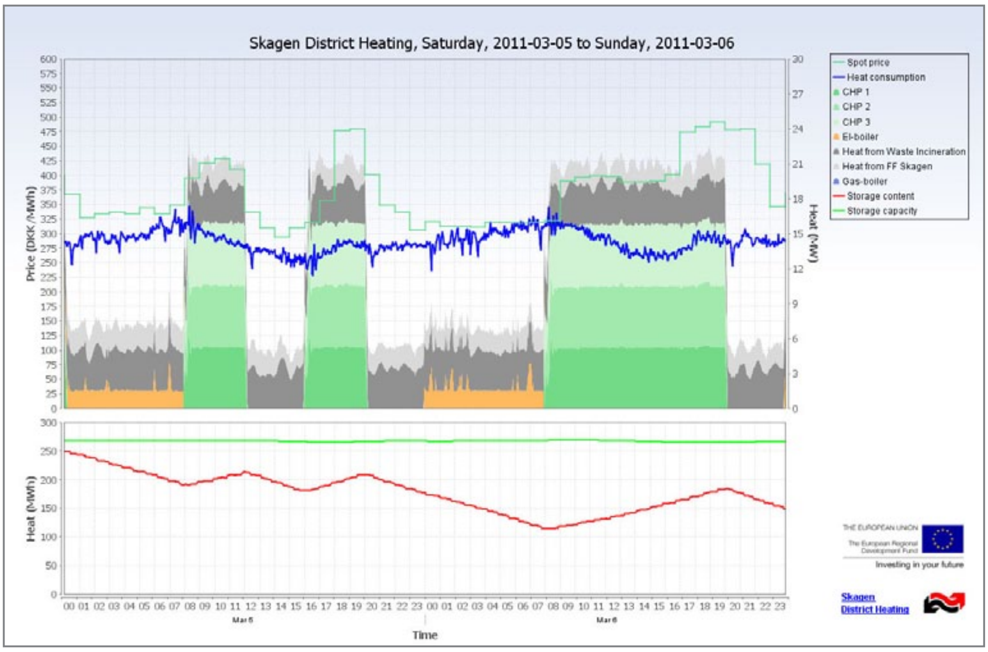


Figure 3: Operating data from the Skagen (Denmark) CHP plant which is based on three gas fired combustion engines with a CHP capacity of ~18 MW$_{th}$. The plant is equipped with a heat accumulator having a 250 MWh thermal storage capacity, a 10 MW electric boiler, and a 37 MW gas fired peaking boiler. The system enables optimal operation in varying market conditions at a total efficiency of over 90%. The plant operation profile can be followed at: http://www.emd.dk/desire/Skagen/

Ancillary services:

Heavy investments in intermittent renewable power generation in recent years have created new requirements for the dynamic system reserve management of electrical grids. The short term balancing needs of power systems create opportunities for plants that can offer fast system reserves. Ancillary services markets will typically reward dynamic capabilities, such as fast starts, stops and load ramps. CHP plants can profitably participate in such markets provided that the power production can be operated independently from the heat production while maintaining high total efficiency at all times.

Carbon emissions cost:

The Emissions Trading Scheme (ETS) allows the plants' carbon emissions to be traded. It is important to consider possible future CO_2 emission costs when conducting feasibility evaluations for district heating investments. The availability and excess, or lack of, carbon credits has significant impact on the overall project economics. Plants with high overall efficiency will be in a good position and natural gas fired plants, in addition to having higher efficiency, produce lower specific CO_2 emissions than coal and oil fired plants. The CO_2 footprint of biomass fired plants is typically low.

Description of natural gas fired CHP technologies in DH application

Many district heating networks face a number of challenges with their existing installed generation capacity. When undertaking investment decisions, the choice of technology is crucial. In the mid size segment of 50–300 MW, the technology choices are: gas fired combined cycle gas turbines, combustion engines, and biomass fired plants. In this chapter the characteristics of the different gas fired solutions are compared. Biomass solutions are beyond this evaluation.

Combined cycle gas turbine plants

In combined cycle gas turbine (CCGT) plants, the electricity is generated by gas turbines and a common steam turbine, driven by steam generated in a heat recovery steam generator (HRSG) that makes use of the hot flue gases directly after the gas turbines. In general, CCGT plants have been developed to have very high electrical efficiency when running in base load.

Industrial gas turbines normally require a natural gas feed pressure of 20–40 bar. Gas turbine flue gas temperatures are close to 600 °C, allowing the utilisation of efficient boiler designs and steam systems. At the same time, the high flue gas temperatures require high quality materials in the boilers and impose relatively long plant start up times. Additionally, the high steam pressures create demands on the skill levels of the operating staff. This is, however, common practice within the power industry.

The steam exhausts from the steam turbine are efficiently used for heating the district heating hot water in steam condensers. The desired hot water temperature is reached using mainly two ways, i.e. in either extraction or back pressure modes. The total efficiency is usually boosted by heating some of the district heating return water in an economiser, located after the HRSG.

A typical CCGT plant configuration consists of one or two gas turbines with heat recovery steam generator (HRSG) units, combined with one common steam turbine unit.

Figure 4: A combined cycle gas turbine (CCGT) plant

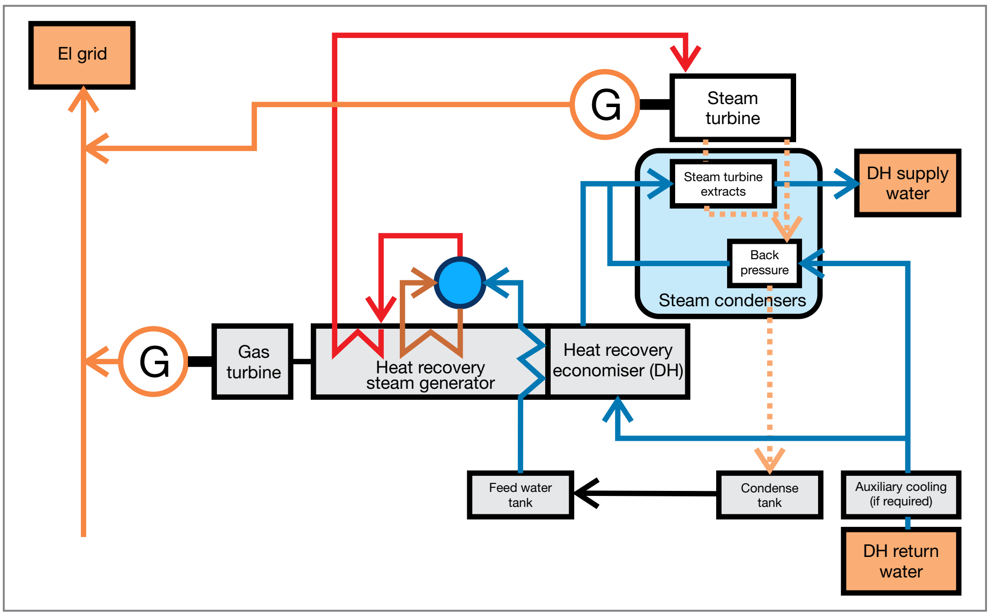


Figure 5: Flow chart of a combined cycle gas turbine back pressure plant with HRSG and district heating (DH) heat recovery

Combustion engine plants

Combustion engine plants are based on multiple independent gas fired generating sets installed in parallel. Each engine is equipped with individual heat recovery from exhaust gases, the engine cooling system including jacket water, lubricating oil, and charge air. The plants comprise a simple cycle configuration with heat recovery based on hot water systems, i.e. there is no intermediate steam system needed. The flue gas temperature is relatively low, at about 400 °C, meaning that high quality heat resistant materials are not needed, thereby facilitating short unit and plant start up times. The heat recovery systems are typically of the hang-on type, which do not have any impact on the engine running and performance. Combustion engines normally require a natural gas feed pressure of 5 bar.

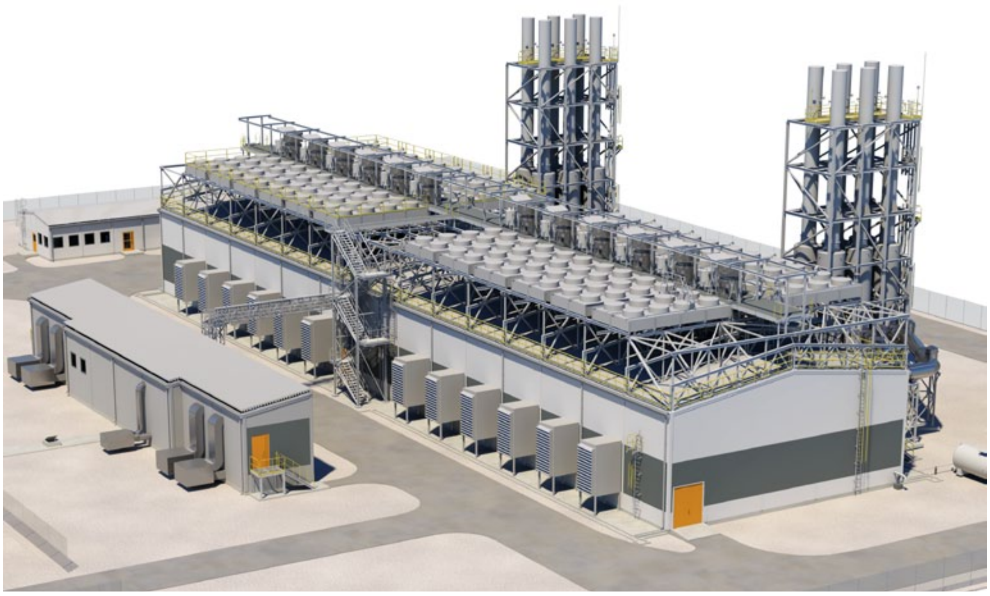


Figure 6: A combustion engine plant with 100 MW_{el} output

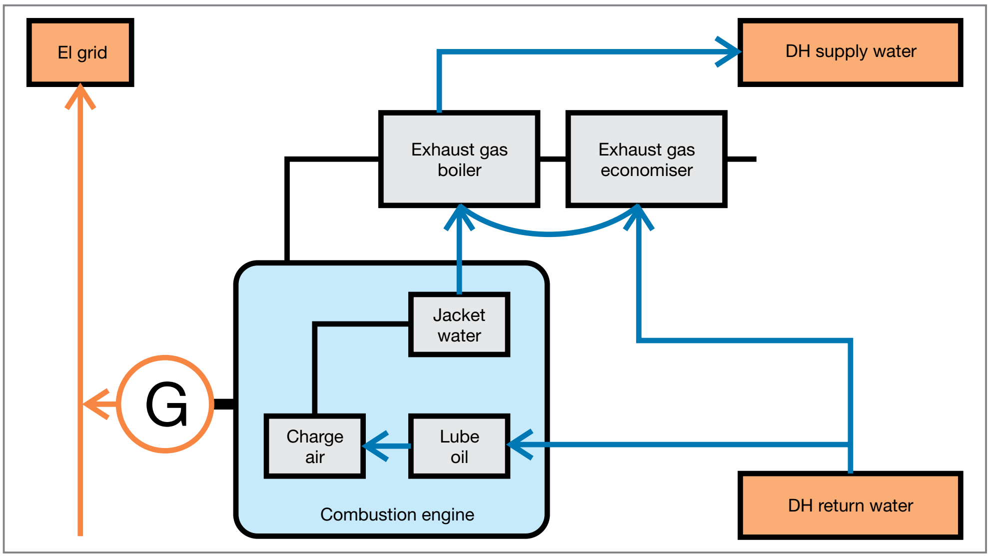


Figure 7: Flow chart of combustion engine heat recovery

Plant setup for a 400 MW_{th} district heating network

Three different CHP plant alternatives are considered in this comparison. Each plant produces the same amount of heat (~165 MW_{th}) at full load, corresponding to approximately 40% of the peak heat load of 400 MW_{th}, i.e. the size of the three CHP plant alternatives is close to the economic optimum for the available heat load. The rest of the heat demand is covered by natural gas fired heat-only boilers.

The actual performances of the different CHP plants differ with varying ambient conditions, but the annual total efficiencies are very similar. In this evaluation the total efficiency of all three alternatives is 88%. Additionally, heat storage for daily heat consumption is included in the evaluation.

The three plant alternatives being compared are configured according to the following:

- Combined cycle gas turbine plant based on 1 gas turbine (1-1-1), producing 220 MW_{el} with 50% efficiency[1]
- Combined cycle gas turbine plant based on 2 gas turbines (2-2-1), each producing 100 MW_{el} (totally 200 MW_{el}) with 48% efficiency[2]
- Combustion engine plant based on 10 units operating in simple cycle mode, each producing 18 MW_{el} (totally 180 MW_{el}) with 46% efficiency.[3]

All these alternatives fulfil the current and foreseen European emission norms.

Characteristics of CCGT plants

Combined cycle gas turbine plants have a high electrical efficiency of close to 50% with a back pressure steam turbine. Typical plant configurations are 2-2-1 or 1-1-1. The load range of combined cycle gas turbine plants depends on the number of generating sets. Gas turbines are reasonably fast to start (25 minutes to full load), but the steam cycle, which is essential to improve the electrical efficiency in district heating applications, requires more time to warm up. The start-up procedure of a combined cycle plant is a sequence where first the gas turbines, then the heat recovery steam generator (HRSG), and finally the steam turbine are started. This procedure typically takes some hours, as does the plant shut down.

1 Source: GTPro (Thermoflow software)
2 Source: GTPro (Thermoflow software)
3 Source: Wärtsilä

The load range of a CCGT plant is relatively narrow. A single gas turbine plant can go down to ~50% electrical load while maintaining reasonable performance. At an electrical load of 50% the heat output is 60% of the maximum output, making the load range on the heat side 60–100%. This limits the use of CCGT plants during warm weather in autumn and spring as a heat load of at least 60% is needed to operate the plant.

Large gas turbine units have higher efficiency than smaller ones. Also, the specific investment costs per installed kW are less as the plant size increases. Therefore, it might initially seem economically wise to construct a single plant, as large as possible.

In CHP applications, CCGT plants are typically overhauled during the summer break when they are normally out of duty for several weeks.

Characteristics of combustion engine plants

Combustion engine plants are based on multiple, parallel, independent units. It is, therefore, easy to optimise the plant size for a specific heat load. The plant can later be extended in small steps by installing additional units as the heat load increases. This modular multi unit configuration additionally enables on-site maintenance work to be carried out one unit at a time. In this way, scheduled overhauls can be sequenced throughout the spring-summer-autumn so that the share of unavailable capacity at any moment is minimized. Multi unit configuration enables firm power availability from n-2 units (n = number of installed generating sets).

The multi unit configuration of combustion engine plants enables a wide load range, both for electricity and heat. This aspect will be discussed in more detail later in the paper.

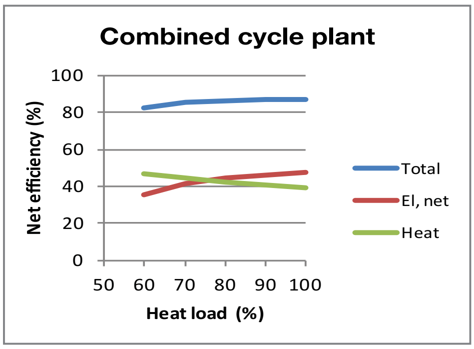
Independent units can be started and stopped quickly, one-by-one, according to heat load and electricity tariffs. These dynamic features enable combustion engine plants to operate both as base load and peak load units.

Due to the multi unit configuration, the plant size has little impact on the specific investment cost per installed kW. Similarly, the plant size has no impact on electrical or total efficiency.

Efficiencies and power-to-heat ratios

As shown in figures 8 and 9, the part load characteristics of the plants differ significantly from each other regarding their power to heat ratios. Combustion engine plants have high part load electrical efficiency and an almost constant power-to-heat ratio (electrical output/heat output) at any load. For gas turbine combined cycle power plants, the electrical efficiency decreases and the heat efficiency increases at part load. This in turn reduces the power-to-heat ratio.

Figures 8 and 9 illustrate the efficiencies and power-to-heat ratios. The minimum electrical load per unit is assumed to be 50% for both technologies. Due to the different part load power-to-heat ratio characteristics, the minimum heat load is 50% for the combustion engines and 60% for the gas turbine combined cycle plants.



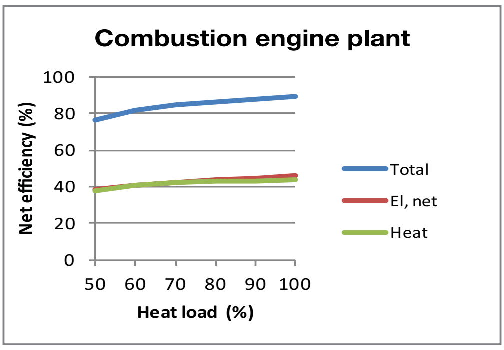


Figure 8: Typical part load performance curves of the compared technologies.

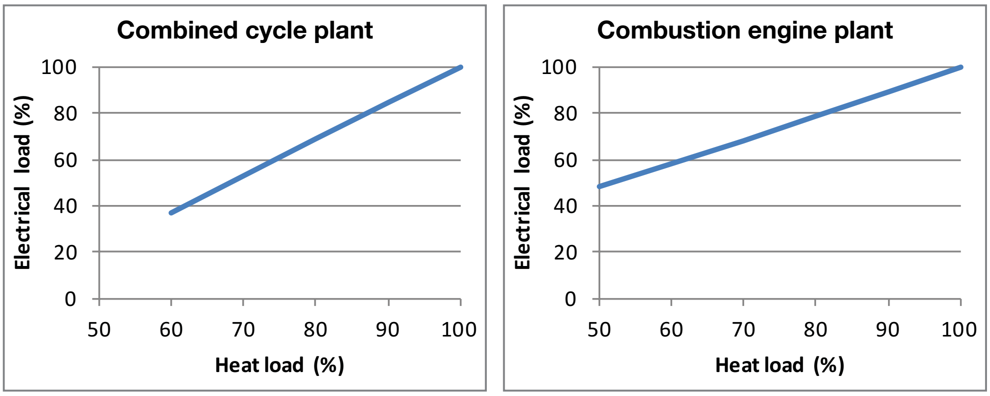


Figure 9: Typical power-to-heat ratio curves of the compared technologies

As shown above, combined cycle gas turbine plants can operate within a heat load range of 60–100% in 1-1-1 configuration, and consequently within a heat load range of 30–100% in 2-2-1 configuration. The electrical efficiency reduces at part load. However, when a 2-2-1 configuration plant is run in 1-1-1 mode, i.e. one gas turbine is shut off at about 50% plant load, the electrical efficiency returns to close to full load efficiency. On the other hand, the total efficiency is not impacted by part load operation as the heat losses are mainly in the flue gases.

CHP plants based on a multi-unit cascading configuration operate at close to peak efficiency in the full load range as the generating sets can be individually turned on and off, depending on the heat load. The minimum heat output of a 10 unit combustion engine plant goes down to 5%, when the minimum load of one unit is 50%.

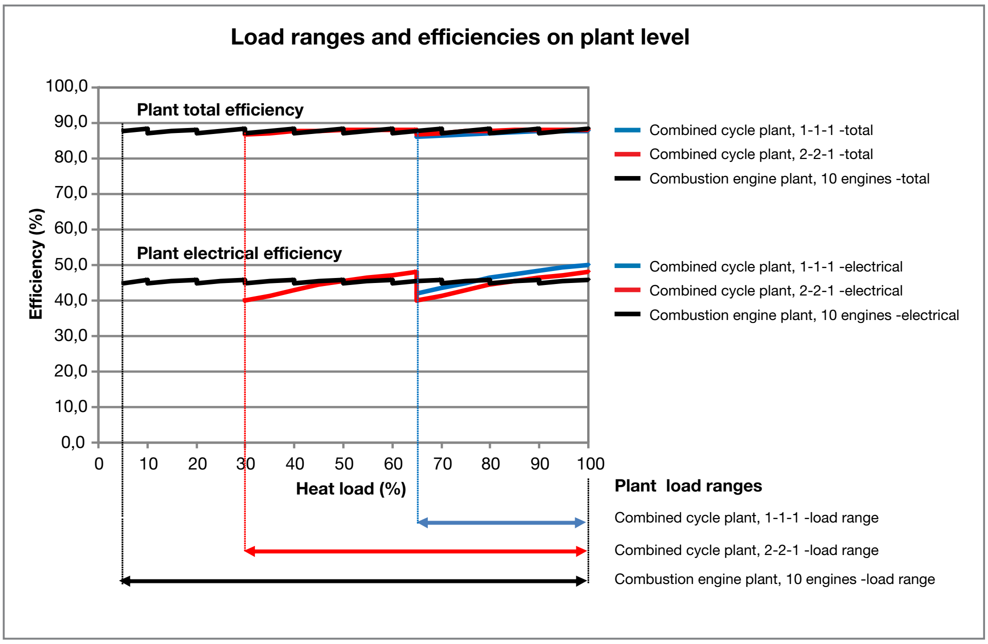


Figure 10: Plant level efficiencies versus heat generation. Note: The combined cycle plant changes from 2-2-1 operation to 1-1-1 operation at 50% electrical load (equal to 60% heat load).

Start-up and shut down times

The compared technologies have different dynamic features. There are differences in start up times, ramp rates, and shut down times.

A CCGT plant can start and reach full load in 1 hour in case of a hot start and if it has been designed for fast starting. Most existing CHP plants are not designed for fast starts, and the hot starting time varies between 1.5 and 3 hours. Shutting down the plant is faster, taking typically about half of the start-up time. Starting from cold obviously takes considerably longer.

Combustion engine plants start and reach full electrical output in 5 to 10 minutes, depending on whether the start is hot or warm. The hot water heat recovery system is typically heated from warm start to full plant heat output in 15 minutes from the start of the engines.

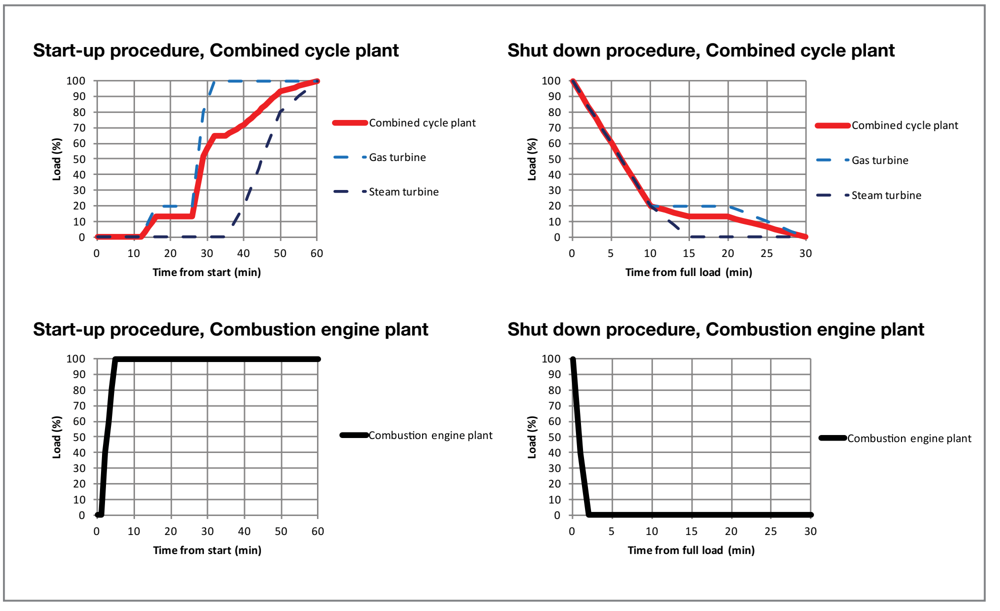


Figure 11: Start up and shut down sequences of the compared technologies.

Typical start-up sequence of a heavy duty CCGT plant (hot start):

1. Equipment check and permission to start (10 minutes from start command)
2. Speeding up and firing the gas turbine (12–13 minutes from start command)
3. Synchronising and loading the gas turbine (15 minutes from start command)
4. Running the gas turbine at minimum stable load to warm and heat up the HRSG (15-25 minutes from start command)
5. Ramping up the gas turbine to full load (25–30 minutes from start command)
6. Synchronising and loading the steam turbine, and starting heat generation (30–60 minutes from start command)
7. CCGT plant at full power and heat production (minimum 60 minutes from start command)

Typical start-up sequence of a combustion engine plant (hot start):

1. Equipment check and permission to start (1 minute from start command)
2. Speeding up, synchronising, and loading the combustion engine (2–3 minutes from start command)
3. Ramping up the combustion engine to full load (3–6 minutes from start command)
4. Ramping up the heat production (5–15 minutes from start command)
5. Combustion engine plant at full power and heat production (15 minutes from start command)

Economic comparison

Input data

In this comparison the produced electricity is assumed to be sold to the national grid. Electricity prices from Germany in 2009 have been used[4]. The electricity prices and price variations can be seen in figure 13. Also in this comparison, the CHP plants get an additional 15 EUR/MWhel from a CHP bonus[5] on top of the electricity market price available from the EEX.

A natural gas price of 25 EUR/MWh (6.9 EUR/GJ)[6] is used as the fuel cost. The corresponding heat price becomes 27.5 EUR/MWhth when determined by calculating the heat produced with a natural gas fired heat boiler running at 91% efficiency. The economic life span of the plants is assumed to be 20 years with a 6% Weighted Average Cost of Capital (WACC). WACC requirements are always investor specific. A higher WACC results in a longer pay back time.

The evaluation is based on an hour by hour (8760 h/yr) analysis of one operational year. The electricity prices and heat demands change hour by hour, and result in different operational profiles for the different plant alternatives.

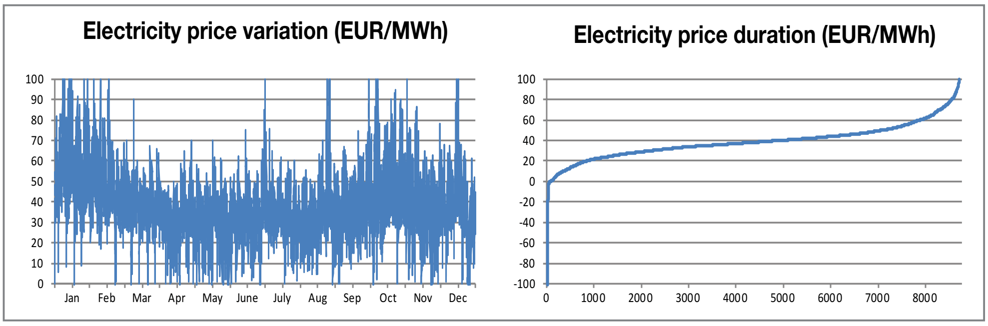


Figure 12: Annual electricity price variations used as a basis for the evaluation

Three alternative solutions; two CCGT plants and one combustion engine plant, all with the same maximum heat outputs and with the following performance and economic data, are compared.

Plant name		Combined cycle plant, 1-1-1	Combined cycle plant, 2-2-1	Combustion engine plant 10 engines
Plant size	MW_{el} / MW_{th}	220 / 167	200 / 167	180 / 164
Plant net efficiency				
Electricity	%	50	48	46
Heat	%	38	40	42
Total	%	88	88	88
Plant load range				
Electricity	%	50–100	25–100	5–100
Heat	%	68–100	34–100	5–100
Prices and costs				
Power plant (EPC)	EUR/kW_{el} net	900	1000	700
Project development / administration	EUR/kW_{el} net	300	300	300
Total investment	EUR/kW_{el} net	1200	1300	1000
O&M costs including consumables	EUR/MWh_{el}	4	4	6

Table 1: Performance values of the compared plant alternatives. Sources: Wärtsilä, GTPro (Thermoflow software). Project development and administration costs are assumed to be 25–30% of the total investment, and contain the investment costs of the heat storage. The O&M costs are estimates based on data from multiple installations, and include costs related to starts and stops.

4 Source: European Energy Exchange (EEX)

5 Source: Federal Ministry of Economics and Technology, Stromnetzentgeltverordnung, Germany, 2005

6 Source: Eurostat, Germany 2009

Optimal plant operation modes

The plants´ annual total efficiencies are nearly equal to their design values, thanks to the effective utilisation of the heat accumulator. However, there are differences in the annual running hours and in the production of heat and electricity.

Observations:

- Due to the heat accumulator, all plant alternatives can be run at optimal load and thus their annual efficiencies are quite similar to the design efficiencies
- The CCGT plants are not operated during the low heat demand summer season because of their narrow load range and long start-up times
- The CCGT plant with a 1-1-1 configuration produces more electricity than the other alternatives due to its bigger plant size and higher base load electrical efficiency
- The CCGT plant with a 2-2-1 configuration gets more operation hours due to its broader load range compared to the 1-1-1 configuration
- The combustion engine plant produces more heat than the CCGT plants because it can operate throughout the summer season (when profitable) and requires less heat boiler production
- Even though the electrical output of the combustion engine plant is lower, it produces proportionally more electricity as it covers a bigger share of the total heat demand
- The wide load range of the multi unit combustion engine plant enables more total annual running hours and produced energy, even though its size is 10-20% smaller.

Plant name		Combined cycle plant, 1-1-1	Combined cycle plant, 2-2-1	Combustion engine plant 10 engines
Plant size	MW_{el} / MW_{th}	220 / 167	200 / 167	180 / 164
Electricity production balance				
Electricity production	GWh_{el}	869	840	940
Fuel consumption	GWh_{fuel}	1 746	1 777	2 045
Annual running hours	h	4 192	4 698	5 820
Heat production balance				
Power plant	GWh_{th}	668	716	862
Heat boiler	GWh_{th}	375	328	181
Total	GWh_{th}	1 044	1 044	1 044
Annual efficiencies				
Electricity	%	50	47	46
Heat	%	38	40	42
Total	%	88	88	88

Table 2: Annually produced energy and plant level efficiencies.

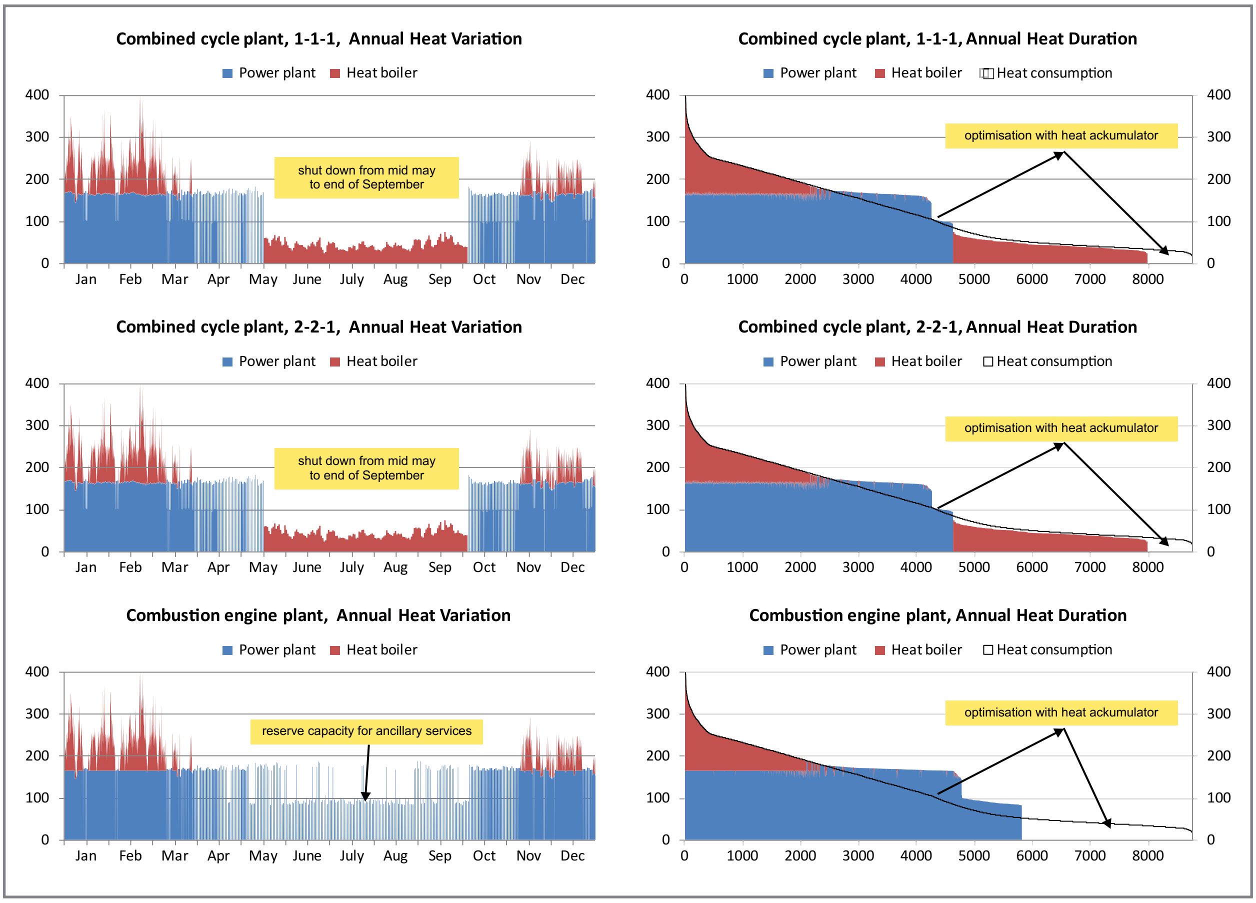


Figure 13: Annual variation and duration curves for the different plant alternatives

The combined cycle gas turbine plants can operate optimally during high heat demand seasons. However, the situation is the opposite during the low heat demand season because of the short running intervals resulting from the high minimum heat output (60%), and the plant´s dynamic characteristics with regard to frequent starting, stopping and loading. The evaluation shows that it is not economically feasible to operate CCGT plants during the low heat demand season, and therefore they are not in operation from May to September.

The combustion engine plant can operate throughout the year, whenever electricity prices allow profitable running. Fast starting, multi unit installations can operate efficiently even at low heat loads. From mid May to mid September, the combustion engine plant operates 5 of the 10 units in CHP mode, thus enabling optimal operation based on the heat loads and electricity prices. The remaining 5 units can be committed to ancillary services operation, e.g. non-spinning reserve, if required and feasible. Alternatively, the units can be operated on part load while selling fast spinning reserve or regulation up/down. This requires economic optimization for each hour.

The potential income from ancillary services is beyond the scope of this paper. In figure 14, examples of the chosen seasonal weekly variation and duration curves for the different plant alternatives are shown. Three typical weeks of the year, representing high, intermediate, and low heat demands are highlighted to present the different characteristics of the plants.

During a February week, all plant alternatives produce full heat output at optimal efficiency.

During an April week, the differences between the three alternatives become evident. Here the CCGT plants need more back up from the heat boiler due to their higher minimum heat load.

During a June week, only the combustion engine plant is running due to its wide load range and low minimum heat load.

Figure 14: Examples of three chosen seasonal weekly variation and duration curves for the different plant alternatives.

Economic results

The feasibility model and calculations for the three alternative plant configurations take into consideration the gas price, the electricity price including CHP bonus, and the key economic investment parameters defined in the previous chapters. The plants are run optimally according to the annual heat demand curve of the evaluated 400 MW_{th} district heating network.

In table 3 it can be noted that the annual operating profits of all three alternatives are similar. The slightly lower electrical efficiency of the combustion engine plant is compensated by the plant's flexibility that allows additional profitable running hours during the spring, summer and autumn. When analysing the financial results, the most evident difference is in the total investment cost, which is noticeably lower for the combustion engine plant. As the capital cost is lower, the investment has a healthier net cash flow, a shorter pay-back time, a higher internal rate of return, and a higher net present value.

A higher weighted average cost of capital (WACC) requirement would result in an increased pay-back time and a decreased net present value for all alternatives. The WACC requirement is investor specific.

Plant name		Combined cycle plant, 1-1-1	Combined cycle plant, 2-2-1	Combustion engine plant 10 engines
Plant size	MW_{el} / MW_{th}	220 / 167	200 / 167	180 / 164
Revenues and cost division				
Revenues from sales of electricity	MEUR / year	39	37	41
CHP bonus	MEUR / year	13	13	14
Total revenues	MEUR / year	52	49	55
Operating costs	MEUR / year	29	28	33
Operating profit	MEUR / year	23	21	22
Capital Costs	MEUR / year	23	23	16
Net cash flow	MEUR / year	0	-1	7
Feasibility of the investment				
Pay-Back Time	years	21	23	11
Internal Rate Of Return	%	6	5	11
Net present value	MEUR	0	-16	76
Total Investment	MEUR	264	260	180

Table 3: Financial results of the evaluation (WACC 6%)

Figure 15: Combustion engine plant.

Table 4 summarises the total annual production costs, which are higher for the combustion engine plant due to its greater number of running hours. On the other hand, the combustion engine plant´s annual net generation cost is lower, mainly because of the smaller plant size based on the electrical output, and the subsequently lower capital cost. The plants are, nevertheless, equivalent in terms of heat generation capacity.

Plant name		Combined cycle plant, 1-1-1	Combined cycle plant, 2-2-1	Combustion engine plant 10 engines
Plant size	MW_{el}/MW_{th}	220 / 167	200 / 167	180 / 164
Production costs				
Fuel	MEUR	44	44	51
Variable O&M	MEUR	3	3	6
- Fuel savings from heat recovery	MEUR	-18	-20	-24
Total	MEUR	29	28	33
Generating costs				
Electricity production costs	EUR/MWh_{el}	33	33	35
Capital costs	EUR/MWh_{el}	26	27	17
Total	EUR/MWh_{el}	60	60	52
- CHP bonus	EUR/MWh_{el}	-15	-15	-15
Net generating costs	EUR/MWh_{el}	45	45	37

Table 4: Annual production and generation costs

Additional earning potential from ancillary services markets

In addition to operating as a normal CHP plant, the earning potential of a CHP plant can be enhanced through the possibility to participate in the emerging dynamic electricity markets. Increased earnings from existing and future ancillary services markets have not been considered in the feasibility comparison above.

The electricity generated is sold to the electricity exchange, and the heat produced is delivered, via the storage, to the district heating network. Additionally the plant could sell fast starting and ramping capabilities to ancillary services markets if its characteristics allow it.

As an example, a 100 MW_{el} CHP plant based on multiple generating sets can be considered as a pool of units. This means for example, that during periods of low heat demand, the plant can be operated in a manner where only one unit is running and nine units are at standstill. These units are available to, for example, fast grid reserve, i.e. non-spinning reserve, markets. The plant generates 10% of its rated capacity at maximum electrical efficiency. Even when the entire plant is at standstill, the fast start up capability enables 100% of the rated capacity to be committed to the secondary frequency control service, for which Germany for instance requires a 5 minutes activation time.

Benefits from decentralised plant locations

CCGT plants are engineered as large as possible to obtain the highest possible electrical efficiency and lowest specific cost. As multi-unit combustion engine plants offer the same efficiencies and the same specific cost level, regardless of the number of units, this opens up the opportunity to install smaller CHP plants at different locations within the district heating system. Such decentralised CHP plants improve the reliability and efficiency of the energy supply, since the production takes place close to the point of consumption. Local heat generation ensures a swift response to changes in the capacity or temperature within the district heating network. Decentralised plant locations also reduce electrical and heat transmission losses, and save energy required for pumping in the district heating network.

Plants in decentralised locations can be operated remotely from a centralised control room, or operated by the system dispatcher (when in ancillary services mode).

Smaller decentralised CHP plants may be connected directly to the medium voltage system (20 kV) of the city. This normally enables savings in transmission fees, as the plants are not connected to the high voltage national system (110 kV or higher), as a larger plant would have to be.

Decentralised plant locations might not be the optimal solution everywhere because of the costs involved for extra locations, plant housing, connection fees, and environmental permits. The natural gas network infrastructure and the feed pressure to the site could impact the location of the plant.


Photo: Göteborgs Energi.

Figure 16: Gas turbine combined cycle plant.

Summary

In this paper, a general overview of district heating systems has been presented. In many existing systems, there is considerable potential for modernising the generating capacity and for improving the efficiency of the entire district heating system. The new challenges that CHP plants need to address are primarily a result of increasing price volatility in the electricity markets, and the variability in e generation created by increasing shares of intermittent renewable power generation capacity, such as wind and solar power.

Different aspects of the CHP plants' technology and performance, as well as their operating economics, have been discussed. Three different mid-range plants, two combined cycle gas turbine plants and one combustion engine plant, in a typical district heating environment have been evaluated.

The study showed that future combined heat and power production should:

- Fulfil environmental norms
- Utilise heat storage
- Have high efficiency
- Have a high power-to heat ratio
- Have good dynamic capabilities (fast start to full production)
- Have a wide plant heat load range

The key findings from the comparison are:

- All three of the compared plant alternatives achieve equivalent annual total efficiencies through heat storage
- A wide heat load range enables an equivalent production of heat and electricity with a smaller size of plant
- Heat storage improves the system's flexibility, enabling optimal electricity and heat production
- The importance of the heat storage increases with a narrower plant heat load range
- High efficiency with a high power-to heat ratio enables more electricity production during the winter season
- Multiple units with fast starts and ramp rates enable dynamic operation during low heat demand seasons
- A high power-to-heat ratio enables a wider operational range at the unit level
- Multiple units enable a wider load range at plant level, and thus provide for flexible operation during intermediate and low heat demand seasons
- A plant with multiple independent units and a slightly lower electrical efficiency can be a more profitable investment in the current, and especially the emerging, market conditions
- Hot water based, hang on type, heat recovery systems are simple and allow electrical efficiency to be independent of heat production
- Distributed production enables efficient energy close to the point of consumption, with very low distribution losses.
- Good dynamic capabilities enable participation in foreseen ancillary services markets that are emerging as a result of increasing shares of intermittent renewable generation
- Multi unit plants can be designed to meet the actual heat load, and can later be enlarged according to need.

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