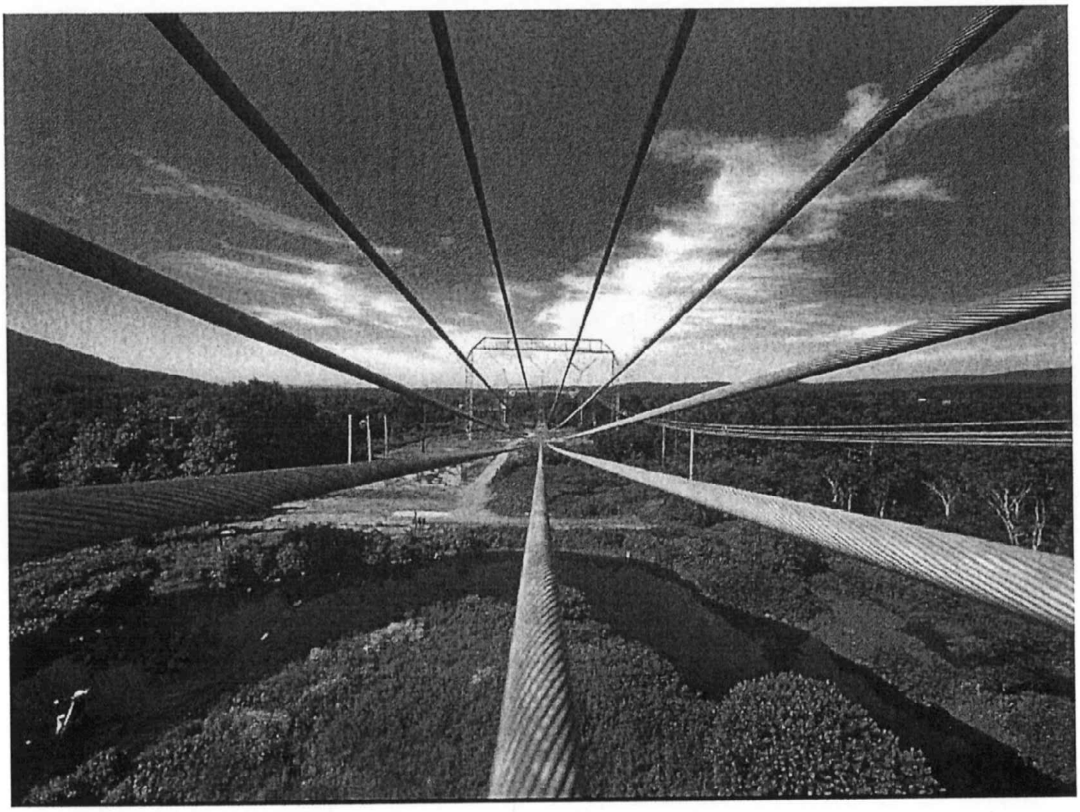
Öhrlings
PricewaterhouseCoopers

An assessment of the potential for high-efficiency cogeneration in Sweden



February 2005

Introduction

Öhrlings PricewaterhouseCoopers (ÖPwC) has been commissioned by the District Heating Committee (Fjärrvärmeutredningen) to analyse and assess the economic potential for cogeneration in Sweden. PwC has engaged the District Heating Consultancy Bureau (Fjärrvärmebyrån) as a subconsultant, and they have provided technical expertise and a model of the district heating systems used by Sweden's urban areas.

During this work, we have encountered several different definitions of cogeneration potential. In this report, the calculation of future cogeneration volume was determined using the following three factors:

- Technical volume potential
- Economic volume potential
- Volume actually implemented

The **technical potential** relates to the maximum volume of cogeneration which can be achieved using the established technology. This calculation takes limited or no account of economic conditions but is rather geared towards assessing the maximum potential of cogeneration from a technical point of view.

The next step in assessing the potential is to test the calculations against a number of economic and commercial requirements. This will lead to a figure smaller than the technical potential because a significant number of projects and investments will fail to meet the pre-defined economic criteria. Any projects or investments which pass the economic test are referred to here as the **economic potential**.

However, the **volume actually implemented** depends on the extent to which investment decisions are taken or implemented in all the areas that have economic potential. Some of these areas may eventually be excluded for a variety of reasons, which is why the volume actually implemented may be lower than the estimated economic potential.

The present report analyses the **economic potential** for cogeneration in Sweden.

The methodology

Sweden's district heating systems are not homogenous, either in terms of energy supply or of the production technology used. In order to carry out a reasonable assessment of the economic potential for new cogeneration within district heating systems, we have considered existing energy supply and production installations. Local information about current district heating systems may be found in the Swedish District Heating Association's (Svensk Fjärrvärme) annual statistics on Swedish district heating systems. On the basis of these statistics and many other sources, the District Heating Consultancy Bureau produced a new simulation model which takes into account the population size of all of Sweden's urban areas and district heating systems. In this model, we analyse in parallel the existing and new district heating systems of all of Sweden's municipalities. ÖPwC has enhanced this model and carried out a number of different simulations which illustrate the effects of a variety of combinations of price developments, volumes and other relevant parameters. Probable value ranges for relevant parameters have been calculated on the basis of summary analyses of the markets concerned, existing studies and consultations with the Administrative Office of the District Heating Committee.

We also provide an insight into some changing market requirements, including those affecting taxation and the green certification and emissions trading schemes.

Calculations of the potential for small-scale cogeneration are based on an assessment of the section of the heating market which has no potential for large-scale cogeneration within district heating systems. The District Heating Consultancy Bureau's model has been used in the calculation of this potential also.

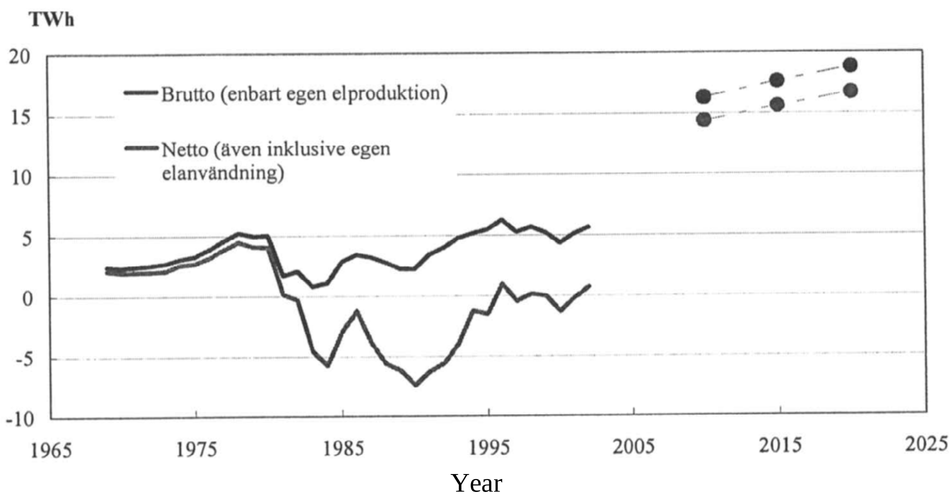
Calculation of the cogeneration potential in industry is based primarily on summary international comparisons.

The results

<u>The potential for cogeneration within district heating systems</u>

The model of the Swedish district heating market has served as a basis for estimating cogeneration potential for 2010, 2015 and 2020. The graph below shows cogeneration potential within district heating systems and historical cogeneration production (measured in net and gross electricity balance,).

Cogeneration within district heating systems



Gross (own electricity production only)
Net (including own electricity consumption)

Graph 1. Gross and net historical cogeneration production for the 1970-2003 period and cogeneration potential calculated for 2010, 2015 and 2020.

The theoretical economic cogeneration potential within district heating systems has been estimated at over 14 TWh for 2010, approximately 15.5 TWh for 2015 and 17 TWh for 2020. On the one hand, this potential is due to the profitability of replacing existing heat production with more inexpensive biomass cogeneration production (which has an economic edge thanks to green certification) and, on the other, to volume growth of the district heating infrastructure. Around 60% of the cogeneration potential identified exists within municipal district heating systems.

Our task has also included clarifying the impact of individual variations in the following basic statistical assumptions:

- Scrapping of the green certification system from 2010 onwards
- Introduction of a concession requirement between integrable systems
- Establishment of a natural gas pipeline extending to Mälardalen and Gävle
- Scrapping of the CO_2 tax on cogeneration production
- Scrapping of emissions trading

The single most important determinant of cogeneration potential is whether the green certification system is scrapped from 2010 onwards or whether the system continues to operate for a considerable length of time. Cogeneration potential drops from 15.6 TWh in a hypothetical situation involving indefinite continuation of the green certification system to 12.5 TWh in a hypothetical situation involving the scrapping of the system in 2010. If the green certification system is maintained indefinitely, any variations in the other basic assumptions would have a relatively limited impact on cogeneration potential.

However, should the green certification system be scrapped from 2010 onwards, cogeneration potential will become considerably more sensitive to any variation in the other basic assumptions, such as the concession requirement for integrable systems, the CO_2 tax and the allocation of emissions allowances. In a hypothetical situation involving the scrapping of the certification system in 2010, cogeneration potential would increase by nearly 2 TWh if the concession requirement were imposed on integrable systems. On the other hand, if, in addition to the concession requirement, the CO_2 tax on cogeneration production were scrapped and if new installations were “grandfathered” allowances, cogeneration potential would increase by a total of 4 TWh.

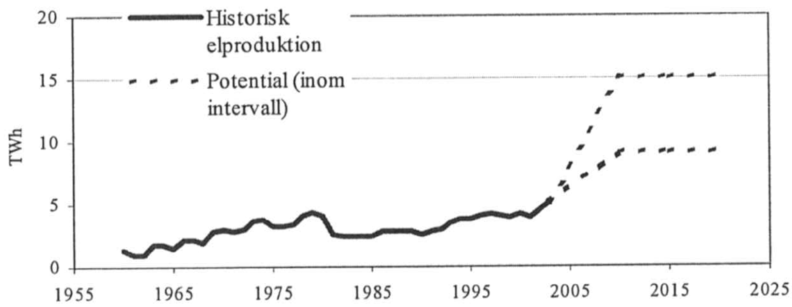
The potential for small-scale cogeneration

The potential within small or medium-scale cogeneration has been estimated on the basis of the heating infrastructure which is not connected to conventional cogeneration, either inside or outside the existing district heating systems. Since development of small-scale cogeneration plants relies mainly on natural gas as a source of fuel, we have considered access to natural gas to be a requirement in estimating this potential. The potential amounts to 0.5-1 TWh.

The potential for cogeneration in industry

The graph below illustrates the potential for cogeneration in industry. Based on international comparisons, it has been estimated that this potential will amount to 10-15 TWh.

The potential for cogeneration in industry



______ Historical electricity production
--------- Potential (within ranges)

Graph 2. Cogeneration production in the 1960-2003 period and cogeneration potential in industry in the 2010-2020 period.

<u>Final observations</u>

As we have been commissioned to analyse the economic potential for cogeneration, the possibility of the volumes stated in this report overestimating the volume of cogeneration which will actually be implemented by 2010, 2015 and 2020 cannot be ruled out. An analysis of the factors impacting on actual implementation is outside the scope of this report. We therefore provide only a brief clarification of certain possible factors:

- Uncertainty about long-term assumptions. Since investment in cogeneration entails a financial undertaking of at least 20 years, it is possible that investors might draw the conclusion that there is a significant risk of the investment calculation changing for the worse during this period.
- Major investment is linked to company size. For municipal enterprises, investing in cogeneration entails a heavy investment cost in proportion to their turnover. A possible alternative could be investment in heat production alone, which would lead to a lower investment cost.
- The existence of respective future conditions and competitiveness of the primary fuel, in particular of biofuel and natural gas.
- Uncertainty about the future development of the electricity market. In general, investment in cogeneration could expose investors to higher risk than investment in heat production, which is why investors may prefer the latter alternative.
- The time factor. Many years could elapse between the initial decision and actual implementation and putting into operation, because of factors including environmental assessment, preparations and the purchasing and implementation process.

By way of conclusion, we emphasise that the possibility of any investment actually made in cogeneration falling short of the economic potential theoretically estimated in the present report cannot be ruled out.

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1. Introduction

1.1 Background

In February 2003, Leif Pagrotsky, Minister of Trade and Industry, appointed Prof Bengt Owe Birgersson as chair of a special body, the District Heating Committee (Fjärrvärmeutredningen), to examine the role of district heating in the heating market (under ToR 2002:160).

In May 2004, the Swedish Government charged the District Heating Committee with the additional task (under ToR 2004:58) of producing a proposal for the implementation in Sweden of Directive 2004/8/EC of the European Parliament and of the Council of 11 February 2004 on the promotion of cogeneration based on a useful heat demand in the internal energy market and amending Directive 92/42/EEC ("The Cogeneration Directive").

The latter task involved proposing amendments necessary for implementing the provisions of Article 5 of the EEC Directive concerning the guarantee of origin of electricity from high-efficiency cogeneration. An initial step towards this end was drafting the Act (2003:437) on the Guarantees of Origin of Renewable Electricity. The committee was also charged with analysing Sweden's potential for high-efficiency cogeneration in accordance with Article 6 of the EC Directive. This analysis had to take into particular account the impact of any changes in the taxation of energy produced by cogeneration (1 January 2004), the emissions trading system (1 January 2005) and the economic potential for further expansion of the district heating network.

As far as possible, this analysis also had to include a clarification of any potential and, where necessary, any changes which needed to be made to the rules governing micro-cogeneration and direct mechanical operation in accordance with Article 3 of the EC Directive. The committee was also tasked with submitting a report on the application of Annex III a concerning special criteria needed in order for small-scale cogeneration and micro-cogeneration to be considered high-efficient.

1.2 Scope

The District Heating Committee has commissioned PricewaterhouseCoopers (PwC) to analyse and assess Sweden's potential for high-efficiency[1] cogeneration, including its potential for high-efficiency micro-cogeneration, in accordance with Article 6 of the EC Directive.

PwC has examined the following:

[1] "High-efficiency cogeneration" means any plant which makes a primary energy saving of at least 10%, compared to references for any alternative production of heat and electricity.

- The potential for existing cogeneration plants according to the definition of 'high-efficiency cogeneration', with a fuel breakdown
- The potential for the construction and deployment of new high-efficiency cogeneration plants by 2010 and 2015 and, if possible, by 2020, including a fuel breakdown
- The potential for small-scale cogeneration (<1 MW_{el}) and micro-cogeneration (<50 kW_{el}) within and outside district heating areas, and their impact on district heating and electricity production.
- The types of cogeneration technology likely to be used (in accordance with Annex I of Directive 2004/8/EC)
- Approximate cost estimates for 2010, 2015 and 2020 respectively (in accordance with Annex IV of Directive 2004/8/EC)
- Assessment uncertainties (by varying the input parameters of the main alternative) and major factors/parameters which could impact on the statistical output.
- This analysis had to illustrate the impact of variations in the following market parameters:

    - The availability of natural gas in the Stockholm region

    - Changes to the current rules governing taxation of cogeneration energy

    - The continued existence of the green certification system after 2010

    - The emissions trading system

    - The introduction of a concession requirement for pipelines connecting adjacent networks

Finally, our remit also included determining technical and economic parameters in consultation with the District Heating Committee.

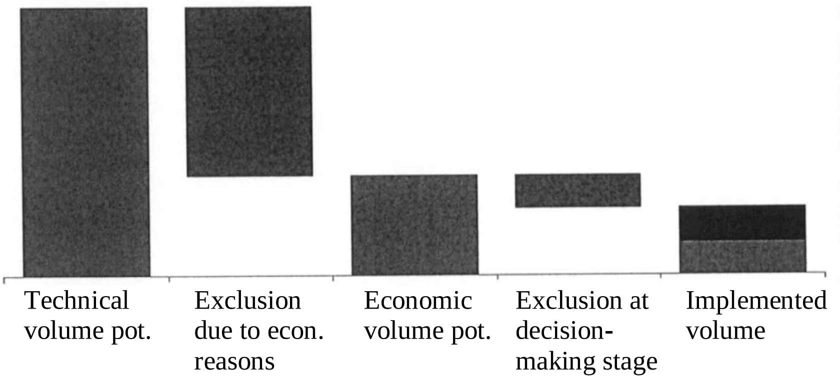
1.3 Definition of the term "potential"

In order to avoid any misunderstandings, let us first provide clarification of what is considered to constitute cogeneration potential for the purposes of this report. In somewhat simplified terms, future cogeneration potential can be defined in three different ways:

- Technical volume potential
- Economic volume potential
- The volume actually implemented

The differences between these methods of estimation of cogeneration volumes are illustrated below.

An illustration of cogeneration potential



Graph 3. An illustration of the technical and economic potential and of the implemented volume.

The **technical potential** relates to the maximum volume of cogeneration which can be achieved using the established technology. This calculation takes limited or no account of economic conditions but is rather geared towards assessing the maximum potential of cogeneration from a technical point of view.

The next step in assessing the potential is to test the calculations against a number of economic and commercial requirements. This will lead to a figure smaller than the technical potential, because a significant number of projects and investments will fail to meet the pre-defined economic criteria. One such criterion might be that return on investment must correspond to the return which is commercially justifiable in the light of the prerequisites for, and the risks of, the undertaking. It should be noted that economic potential is typically calculated with simplified assumptions of some kind, which therefore injects a degree of uncertainty into the result. In addition, we have made some assumptions about the timescale necessary for the realisation of the potential. Any projects or investments which pass the economic test are referred to here as the **economic potential**.

However, the **volume actually implemented** depends on the extent to which investment decisions are taken or implemented in all the areas that have economic potential. Some of these areas may eventually be excluded for a variety of reasons, which is why the volume actually implemented may be lower than the estimated economic potential. For example:

- Anyone intending to decide upon and invest in cogeneration may come up with an overall assessment which differs from the economic potential calculated here. Investors may for example conclude that any future uncertainties relating to energy taxation, green certification, prices etc. are so great that it is best to bide their time or abandon the investment altogether. Other impediments could include the company and/or its owners concluding that the cost of investment is too great to enable the operation to finance itself.
- Implementation and deployment may be postponed because of problems in obtaining an environmental permit, delivery of intermediate goods or the plant or the like.
- The circumstances of a given location and/or investment may differ from the simplified assumptions we used when calculating the economic potential.

We have been commissioned by the District Heating Committee to analyse **the economic potential**, which is why the possibility that the volumes stated in this report overestimating the volume of cogeneration which will actually be implemented by 2010, 2015 and 2020, respectively, cannot be ruled out.

1.4 Methodology

PwC has engaged the District Heating Consultancy Bureau as a subconsultant, and they have provided technical expertise and produced a new model of the population size and district heating systems of all of Sweden's urban areas.

Our calculations of the cogeneration potential within district heating systems are based on the model produced by the District Heating Consultancy Bureau. Probable value ranges for relevant parameters have been calculated on the basis of summary analyses of the markets concerned, existing studies and consultations with the Administrative Office of the District Heating Committee. Cogeneration potential has been calculated for different values of the relevant parameters. In addition, the impact on cogeneration potential of changes in market conditions has been illustrated.

Our calculations of the potential for small-scale cogeneration are based on an assessment of the section of the heating market which has no potential for large-scale cogeneration within district heating systems.

Our calculations of the cogeneration potential in industry are based primarily on summary international comparisons.

1.5 Limitations

Because of the very tight time and budget constraints on this task, we have not had the scope to carry out detailed specific and tailored analyses of each of Sweden's local district heating systems. For this reason, our analysis has followed a standardised procedure.

Nor has the PwC had any opportunity within the remit of this task to verify the accuracy of any publicly available documents or other background material. Therefore, PwC cannot and does not accept responsibility for any gaps in the background material, or any consequences resulting from these.

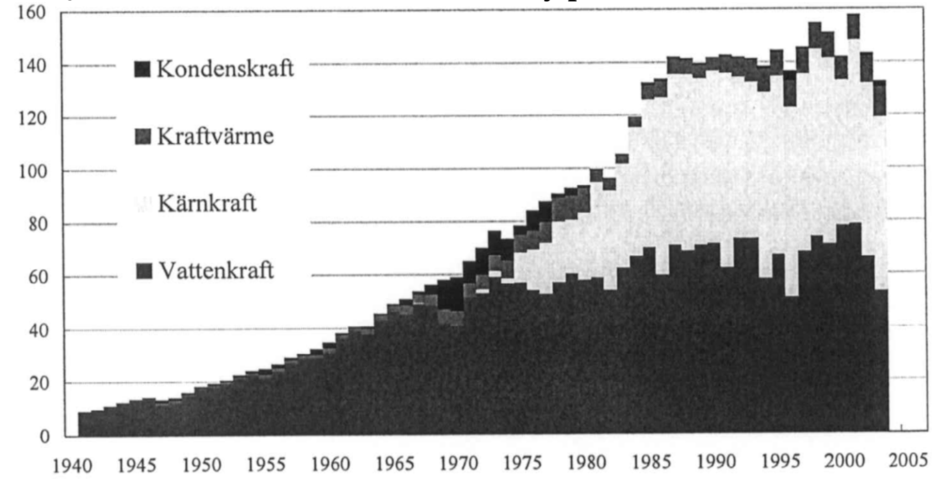
We have used a variety of methods to assess the cogeneration potential within district heating systems, industry and small-scale cogeneration. In chapters 4 to 6, we describe the limitations of each of the methods used.

2. The role of cogeneration in Swedish energy production: a historical overview

The energy sources used in the production of heat by Sweden’s district heating networks have varied over the years, in response to changes in the prevailing market conditions. This has particularly affected the use of cogeneration and its position in the Swedish electricity market.

Historically, cogeneration has played a minor role in Sweden’s power production. The graph below illustrates Sweden’s power production between 1941 and 2003.

TWh/year **Sweden’s electricity production**



From top to bottom: Condensing power, Cogeneration, Nuclear power, Hydro-electric power

Graph 4. Sweden’s electricity production in the 1940-2003 period. Source: 50 years of district heating in Sweden, The Swedish District Heating Association

Prior to 1965, the electricity sector was dominated by hydro-electric power. Heat production was utilised only in years when Sweden experienced a shortage of rainfall or as top-up electricity.

After 1980, the combined impact of nuclear power and hydro-electric power reduced the scope for cogeneration in the power balance. This was due to the fact that, in the 1970s, Sweden chose to invest in nuclear power generation, which significantly increased access to electricity.

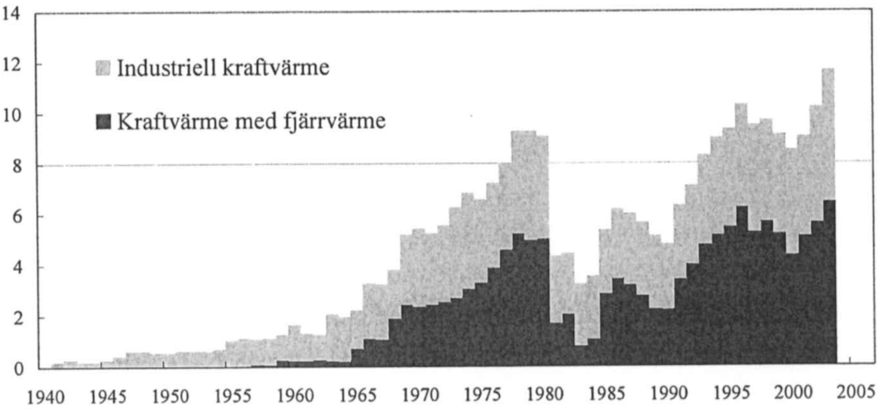
Between 1965 and 1980, heat production was needed to maintain the power balance. During this period, both industrial cogeneration and cogeneration within district heating systems were used to reduce the need for condensing power generation. Industrial cogeneration is mainly linked to the steam demand of the paper and pulp industry. Most cogeneration plants were fired by oil during this period.

As more nuclear power stations were put into operation in 1981 and as the oil price reached new heights after the 1979/80 oil crisis, the proportion of cogeneration in Sweden's power balance dropped to 4.5%, from nearly 10% in 1980. During the 1980s, cogeneration's share in the market varied between 3 and 4.5%, depending on access to hydro-electric power and electricity demand.

Many cogeneration plants within district heating systems switched to coal burning during the first half of the 1980s in order to reduce the cost of electricity and heat production. Afterwards, in the 1990s, the proportion of cogeneration increased to 6% as many existing cogeneration plants were converted to enable them to use wood fuels and almost all new cogeneration plants were built to run on the same fuels.

The graph below shows the breakdown of cogeneration production between industry and district heating sectors. Although power was generated by cogeneration on a small scale throughout the greater part of the 20th century, it was only in the mid-1960s that cogeneration production experienced major expansion. That expansion took place within both industry and district heat production.

TWh/year **Electricity production in Sweden's cogeneration plants**

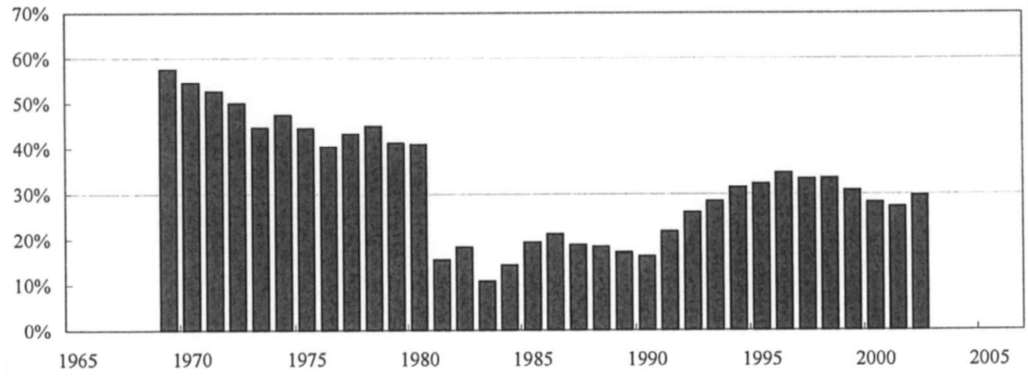


From top to bottom: Industrial cogeneration, Cogeneration attached to district heating

Graph 5. Electricity production in Sweden's cogeneration plants. Source: 50 years of district heating in Sweden, The Swedish District Heating Association

The graph below shows the proportion of district heat produced by cogeneration plants in the 1969-2003 period. In 1969, the proportion of district heat produced from cogeneration amounted to 55%, then gradually decreased to 40% in 1980 before suffering a dramatic drop to just below 20%. This decrease may be explained by the conversion of district heat production, whereby oil-fired cogeneration production was replaced by heat production fired by fuels such as coal, biofuels and peat. Electrically heated boilers and heat pumps were also introduced into heat production, because the increased electricity production (due to investment in nuclear power) made it possible for district heat producers to buy electricity at favourable prices and channel it into district heat production. This eclipsed other fuels. However, after 1990, the proportion of cogeneration produced from district heat production increased again.

The proportion of district heat produced in cogeneration plants

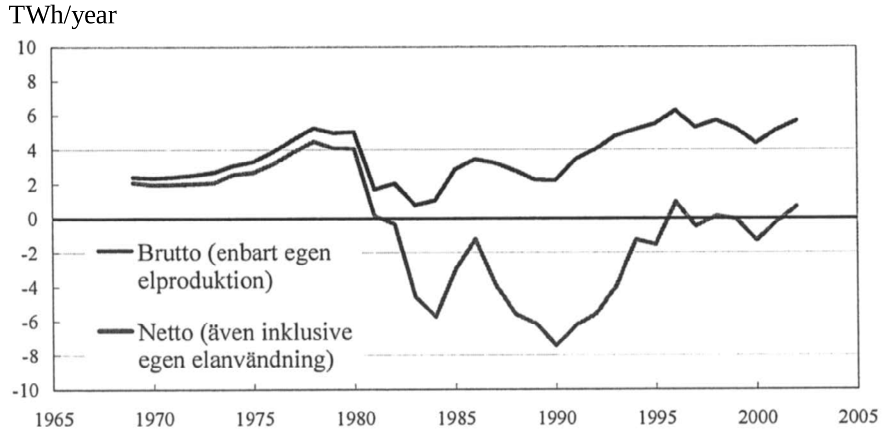


Graph 6. The proportion of district heat produced in cogeneration plants. Source: 50 years of district heating in Sweden, The Swedish District Heating Association

The graph below shows the electricity balance of Sweden's net and gross district heat production for the period 1970-2003. Net production equals gross production minus operating electricity and electricity used to power heat pumps and electrically heated boilers.

The period prior to 1980 was characterised by the fact that only a small proportion of electricity production was used for operating electricity. The period after 1980 was characterised by a transition to a district heating production based largely on heat pumps and electrically heated boilers, thanks to district heat producers being able to buy electricity at favourable conditions. However, since 1990, the consumption of electricity within the district heating industry has been in decline.

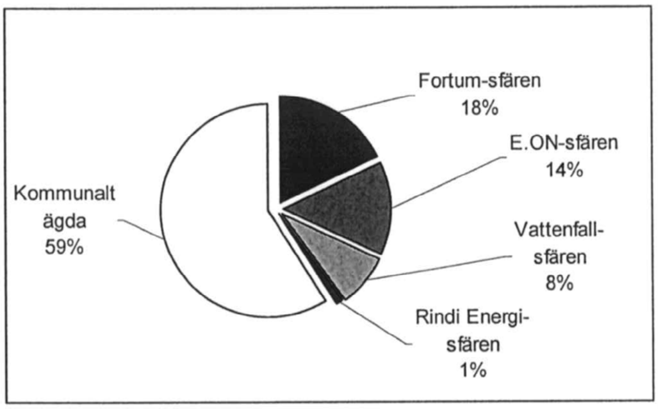
Electricity balance of Sweden's district heat production



Gross (own electricity production only)
Net (including own electricity consumption)

Graph 7. Electricity balance of Sweden's district heat production. Source: The Swedish District Heating Association

The ownership structure of Sweden's district heating infrastructure is shown in the chart below.



Municipality-owned, 59%
Fortum, 18%
E.ON, 14%
Vattenfall, 8%
Rindi Energi, 1%

Graph 8. District heat sales for each ownership segment in 2002: total 47 TWh.

Source: The District Heating Committee's Study (SOU) 2004:136, Interim report, Appendix 2.

3. Cogeneration technologies

Annex I of EU Directive 2004/8/EC cites 11 cogeneration technologies[2] for the combined production of electricity and heat, which have broadly been divided into large-scale and small-scale technologies. Some technologies, like gas turbine with heat recovery and internal combustion engine, straddle the two technology types.

Large-scale technologies (larger than 1 MW_{el})

- Steam backpressure turbine
- Combined cycle gas turbine (CCGT) with heat recovery
- Steam condensing extraction turbine
- Gas turbine with heat recovery
- Internal combustion engine

Small-scale technologies (smaller than 1 MW_{el})

- Internal combustion engine
- Gas turbine with heat recovery
- Microturbines
- Stirling engines
- Fuel cells
- Steam engines
- Organic Rankine cycles
- Any other type or combination of technology falling under the definitions laid down in Article 3(a).

The following section discusses the distribution of these technologies in Sweden and examines which of these are likely to be in use in Sweden in 2020. The District Heating Consultancy Bureau has provided valuable input for this technical section.

The factors essential for assessing the probability of a given technology being in use in Sweden in 2020 are whether it is currently in use, its competitive power in relation to other technologies and market conditions in the period up until 2020, e.g. to what extent these technologies have been used internationally and, therefore, to what extent they could expand into a larger market.

[2] For a more detailed technical description see, for example, Elforsk, *Electricity from new plants 2003*, Appendix A and Protermo 1999, *Guidelines for Calculating Energy Generation in Combined Heat and Power Plants.*

3.1 Large-scale technologies

3.1.1 Today's technologies

Steam backpressure turbine

Steam backpressure turbine is the prevailing technology used by today's cogeneration plants in Sweden, both in terms of industrial exploitation and cogeneration within district heating systems. A steam backpressure plant consists of a boiler with a backpressure turbine. The steam created in the boiler under high pressure and temperature is conducted into the turbine and the power thus produced is transferred by a shaft to a generator. In industrial exploitation, any remaining heat is distributed to meet existing industrial heat demand, whereby the steam is condensed into water. In district heating applications, the remaining heat, now at a lower pressure and temperature, is conducted into a turbine condenser, with the steam condensing into water while heating circulating district heating water. What this means is that, from a technical point of view, electricity is always produced first and heat second. It is not possible to do it the other way around.

The capacity range of backpressure turbines is between a few MW_{el} and around 100 MW_{el}. Large cogeneration plants equipped with backpressure turbines have several parallel turbines. The smallest backpressure turbines are those in Lomma, Malå and Myresjö (1.6-4.4 MW_{el}). The smallest standard capacity for biofuels and district heating is 8-12 MW_{el} (Falun, Sala, Härnösand, Kiruna and Nässjö). There are simpler versions of a backpressure turbines in Eksjö and Tranås, where super-heated water boilers generate steam of their own from the low-pressure steam, which produces a low electricity turbine output of 1-2 MW_{el}.

In terms of output parameters, the largest cogeneration plants equipped with backpressure turbines use conventional steam pressure (100-180 bar) and temperature (500-540°C). This performance represented the state of the art in the 1950s. Swedish cogeneration plants do not use any high-output turbines with supercritical pressures (which is today's most advanced technology), mainly because of the small size of the plants and the fact that the fuels are problematic. In order to increase their electricity output, some plants have intermediate superheating between a high-pressure turbine and a medium/low-pressure turbine.

Small cogeneration plants use lower steam pressures and temperatures, e.g. 63 bar and 510°C in Falun and 40 bar and 480°C in Malå. This provides a smaller electricity output in relation to heat production.

Combined cycle gas turbine (CCGT) with heat recovery

A combined cycle consists of a combination of a gas turbine and a backpressure turbine. Steam is generated from hot flue gases from the gas turbines. Where a combined cycle is fired with natural gas, the technology is called "CCGT". A CCGT plant consists of one or more gas turbines and one or more steam turbines.

The only pure combined cycle plant in Sweden is in Ängelholm. In recent years, the difference between the market price of electricity and natural gas, including taxes, has been small, which is why the owner of the plant has taken the initiative to construct a substitute heat production plant fired with recycled wood. There was a similar, liquefied petroleum gas-fired CCGT plant in Karlskoga, but it was shut down in 2000 and dismantled.

A large CCGT plant with a capacity of 260 MW_{el} has been commissioned by Göteborg Energi, with a scheduled launch date of 2006. Sydkraft is planning a large plant for Malmö.

A small-scale combined cycle plant (of 800 kW_{el}) fired by biogas is situated in the outskirts of Helsingborg.

The parallel-connected combined cycle in the Värta plant, Stockholm, called the pressurised fluidised bed combined cycle (PFBC), which is fired with solid fuels in the Värta plant, Stockholm, is a different variation on a pure, series-connected combined cycle.

Steam condensing extraction turbine

Steam condensing extraction turbines can be included under "cogeneration production" if some of the steam is extracted before the last turbine stage and used for heat generation.

Pure condensing extraction turbines are usually used in Sweden, as conventional condensing power plants have not historically proved competitive in the Swedish electricity market. However, there are some generators which use what is known as a "condensing tail" connected to the back of a backpressure turbine. These generators are found in Stockholm, Norrköping and Västerås. Another common solution is connecting re-coolers (using either air or water) to the district heating cycles of backpressure turbines (e.g. in Örebro, Malmö, Borås and Linköping). All these technological variations make it possible for the plant to produce electricity in a condensing-based mode when there is no demand for heat. Generally, this option is only taken when electricity prices are very high and heat demand low.

Gas turbine with heat recovery

This technology consists of a gas turbine which is combined with a heat exchanger, where the outlet flue gases from the gas turbine are cooled with circulating district heating water.

There is a natural gas-fired gas turbine with heat recovery situated in Lund.

Smaller-scale gas turbines with heat recovery also exist.

Internal combustion engine

There are a few large diesel engines used as cogeneration plants. They may be found, among other places, in Oskarshamn (7 MW_{el}), Gothenburg and Linköping (14 MW_{el}).

3.1.2. Tomorrow's technologies

Given today's key enablers of new cogeneration production, i.e. higher long-term electricity prices, instruments for reducing carbon dioxide emissions (emissions trading) and a higher proportion of electricity produced from renewable energy sources (certificates trading), there are two technologies identified in the Directive which are of particular interest to Sweden. These are:

- Biofuel-fired backpressure turbines
- Gas-fired combined cycles

Biofuel-fired backpressure turbines are of interest to Sweden because biofuel is available at competitive prices and enables high overall efficiency.

Gas-fired combined cycles are of interest to Swedish municipalities which have access to natural gas. In relation to other technologies, large plants entail low investment costs, and benefit from high electricity output and overall efficiency.

The two other large-scale technologies (steam condensing extraction turbines and gas turbines with heat recovery) are deemed to be of lesser interest. This may be explained by the fact that they have difficulty competing with biofuel-fired backpressure turbines and gas-fired combined cycles, as described above.

Steam condensing extraction turbines have a high electricity output, but lower overall efficiency, and are therefore hard to justify on either environmental or economic grounds, compared to the backpressure turbine.

A gas turbine with heat recovery has a lower electricity output than combined cycles and is therefore of less interest in terms of possible use in Sweden.

3.2 Small-scale technologies

3.2.1. Today's technologies

<u>Gas turbine with heat recovery</u>

This technology is available for plants with a minimum output capacity of 100 kW_{el}. Turbec in Malmö, for example, delivers ready-to-use modules with 105 kW_{el} and 167 kW_{heat}.

<u>Internal combustion engine</u>

A number of small-scale cogeneration plants with internal combustion engines use biogas in the form of sludge gas from waste water treatment plants or in the form of landfill gas from landfills.

<u>Microturbines, Stirling engines, fuel cells, steam engines and organic Rankine cycles</u>

Microturbines, Stirling engines, fuel cells, steam engines and organic Rankine cycles are not, as a rule, used in Sweden's cogeneration plants. Demonstration plants with fuel cells have, however, been known to operate. Addpower AB is planning a demonstration-stage ORC project in Högenäs.

<u>Other types of technology</u>

An application based on thermal solar cells in wood powder-fired micro-cogeneration plants is used in a project jointly run by two colleges, Högskolan Dalarna and Mälardalens Högskola.

3.2.2. Tomorrow's technologies

From an international perspective, Sweden is in a special position when it comes to its potential for introducing small-scale cogeneration production on a broader scale. The Swedish heating market is driven mainly by reliable access to low-tax biofuels. Internationally, however, cogeneration production which relies on natural gas is gaining ascendancy. Where biofuels are used as a source of energy, there is substantially less access to commercial technology. Although development projects involving the use of biofuels in small-scale cogeneration certainly do exist, it will probably take some time before commercial applications of this technology become available.

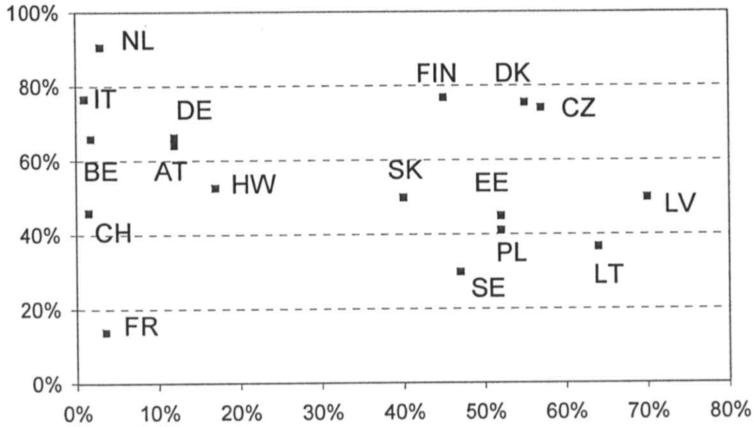
As a result, the potential for small-scale cogeneration in Sweden in the short term would require the use of gas engines or gas turbines. That, however, presupposes access to natural gas.

In the longer term, there is a possibility of fuel cells being used to power cogeneration production in Sweden. Fuel cells are a technology which enables electricity to be produced from hydrogen. Currently, however, fuel cells, too, require access to natural gas (because hydrogen is generated from natural gas).

4. The potential for cogeneration within district heating

Sweden is in a unique position in the EU in that a mere 30% of the heat demand of its district heating systems is supplied by cogeneration plants. No other EU Member State has so much district heating with so little cogeneration. In the long term, therefore, more cogeneration plants could be constructed within existing district heating systems, given the right conditions to encourage new cogeneration.

Production of district heat through cogeneration



The market share of district heating

Graph 9. The market share of district heating (in the domestic market) and the share of heat produced from cogeneration compared to district heat in some other European countries. (Source: Werner, S. (2001), Rewarding Energy Efficiency: The perspective of emissions trading. Euroheat & Power – Fernwärme International 30 (2001):9, 14-21.

Given the limited potential for expansion of both hydroelectric and nuclear power generation, a number of changes to the Swedish electricity market could promote the future expansion of cogeneration, such as the introduction of green certification, charging higher prices for electricity and increasing electricity demand.

4.1 The model

In order to calculate the economic potential for cogeneration within district heating systems, we have produced a simulation model based on all existing and potential new district heating systems in Sweden. The model calculates the income and costs of both existing systems and those which would pertain if a cogeneration plant were to be built. Where investment in cogeneration is profitable, it is included in the calculated potential. In the following section, we provide further details in this regard.

4.1.1. Data inputs for, and the decision-making logic of, the model

Sweden's district heating systems are not homogenous, either in terms of energy supply or of the production technology used. In order to make a reasonable assessment of the economic potential for new cogeneration in different contexts, we needed to take account of existing energy supply and existing production installations. To this end, we needed local information about Sweden's current district heating systems, which we obtained from annual district heating statistics produced by the Swedish District Heating Association.

This information has been used as input data to a simulation model which analyses existing and potential new district heating systems in all of Sweden's municipalities in parallel. The simulation model is a simplification of an analytical procedure used in HEATSPOT, an analysis model developed by David Knutsson, a PhD student at the Department of Energy Technology at Chalmers Tekniska Högskola in Gothenburg as part of the Nordleden project.

The advantage of an applied analytical procedure is that it enables local situations to be used to calculate the national economic potential in situations involving different national conditions, including, among other things, the tax system, CO_2 trading and certificate prices. However, the model and the analytical procedure constitute a standardised method for analysing district heating systems, as, in this task, we have not been able to subject each district heating system to individual, specific analysis in any great detail. This procedure should also produce a relatively precise calculation of the potential.

The calculation used is a realistic one-year calculation based on a base year and expressed in monetary terms.

<u>Data inputs</u>

The data inputs below have been used in the simulation model as baseline information on current district heating systems in Sweden.

- Based on the Swedish District Heating Association's statistics for 2001[3,4], the existing plants' capacity can be divided into a total of 11 groups based on their production technology and fuel:
    - Waste-fired cogeneration
    - Waste-fired heat production
    - Waste heat
    - Heat pumps
    - Biofuel-fired cogeneration
    - Natural gas-fired CCGT (combined cycle gas turbine)
    - Coal-fired cogeneration
    - Biofuel-fired heat production
    - Natural gas-fired cogeneration
    - Oil-fired cogeneration
    - Any remaining capacity is presumed to be oil-fired heat production

- Normal annual volume for district heat sold in Sweden has been estimated on the basis of the Swedish District Heating Association's statistics for 2001.

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[3] This statistic covers approximately 96% of Sweden's district heating infrastructure. The four percentage points not covered by the statistics were included in the calculated cogeneration potential.

[4] The Swedish District Heating Association's statistics for 2002 did not provide the level of detail (output by installation) required for the analysis, which is why we used the 2001 statistics.

- The existing production line-up has been completed with known new builds and approved production plants, primarily waste facilities, but also some cogeneration plants, such as the Rya CCGT plant in Gothenburg. However, the Öresund plant in Malmö has been excluded as no decision has yet been made on its construction.
- All systems included in the model are presumed to be under municipal ownership, i.e. one network for each municipality. Existing or planned pipelines connecting the different municipalities have been included so that we can take into account the parallel operation of different district heating systems. Currently, there are 25 existing or planned connecting pipelines. In order to simplify things, we have presumed that networks in Stockholm are integrated although they are, in fact, three separate networks.

Municipalities which are currently integrated					
Ale	with	Gothenburg	Lomma	with	Lund
Botkyrka	with	Södertälje	Mjölby	with	Linköping
Burlöv	with	Malmö	Mölndal	with	Gothenburg
Eslöv	with	Lund	Nybro	with	Kalmar
Hallsberg	with	Örebro	Partille	with	Gothenburg
Hallstahammar	with	Västerås	Salem	with	Södertälje
Huddinge	with	Södertälje	Sigtuna	with	Stockholm
Håbo	with	Upplands Bro	Sollentuna	with	Stockholm
Järfälla	with	Stockholm	Sundbyberg	with	Solna
Kumla	with	Örebro	Tyresö	with	Haninge
Landskrona	with	Helsingborg	Upplands Väsby	with	Stockholm
Lidingö	with	Stockholm			

Graph 10. Municipalities whose district heating systems have been integrated with adjacent networks.

- Proximity to existing natural gas networks has been noted in 34 municipalities.

Municipalities close to existing natural gas networks			
Ale	Halmstad	Landskrona	Svalöv
Bjuv	Helsingborg	Lerum	Svedala
Burlöv	Hylte	Lomma	Trelleborg
Båstad	Höganäs	Lund	Varberg
Eslöv	Klippan	Malmö	Vellinge
Falkenberg	Kungsbacka	Mölndal	Åstorp
Gislaved	Kungälv	Partille	Ängelholm
Gnosjö	Kävlinge	Staffanstorp	
Gothenburg	Laholm	Stenungsund	

The logic of the model

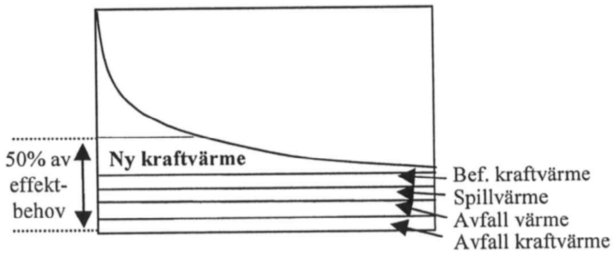
- The simulation model indicates such assumptions as tax rates, emissions allowances, certificate prices, fuel prices, electricity prices, and the output and efficiency of cogeneration plants. The model also provides details of the required return, the cost of investment in new cogeneration and the minimum size of plant which will dictate the volume of investment in new cogeneration.

- The volume which provides the basis for the calculation of potential is based on the anticipated sales volume in the future. Heat production is calculated on the basis of a 9% heat loss from distribution networks. The anticipated future sales volume is estimated by setting the maximum potential for each urban inhabitant at 9 MWh/year. In systems where the use of district heating does not reach this level, it is assumed that the remaining potential could be achieved in stages: 30% by 2010, 40% by 2015 and 50% by 2020. The declining pace of penetration is due to the rising marginal costs of connecting additional users to the district heating network. No volume increase is assumed for systems where average consumption already exceeds 9MWh/inhabitant.

- The merit order is based on existing production costs and is assumed to be fixed for the different production technologies. The fuels are used in the following order:

    - Waste-fired cogeneration
    - Waste-fired heat production
    - Waste heat
    - Biofuel-fired cogeneration (existing)
    - Biofuel-fired cogeneration (new)
    - Natural gas-fired CCGT (existing)
    - New natural gas-fired CCGT (new)
    - Coal-fired cogeneration
    - Biofuel-fired heat production
    - Heat pumps[5]
    - Natural gas-fired cogeneration
    - Oil-fired cogeneration
    - Oil-fired heat production

- Annual heat production is simulated for each district heating system. This applies in equal measure to the existing production line-up and to hypothetical situations involving construction of a biofuel-fired cogeneration plant or a gas-fired CCGT plant (where natural gas is available). The size of a newly-built cogeneration plant is determined as the difference between half of the power demand and the sum of the capacity installed in existing production plants which have a higher priority. Experience has shown that 50% of the power demand is a suitable definition of the size of a cogeneration plant within a district heating system. In a standardised service life graph, heat production is estimated at 2 882 operating hours. Service life is based on climatic conditions in the Stockholm region.



New cogeneration Existing cogeneration

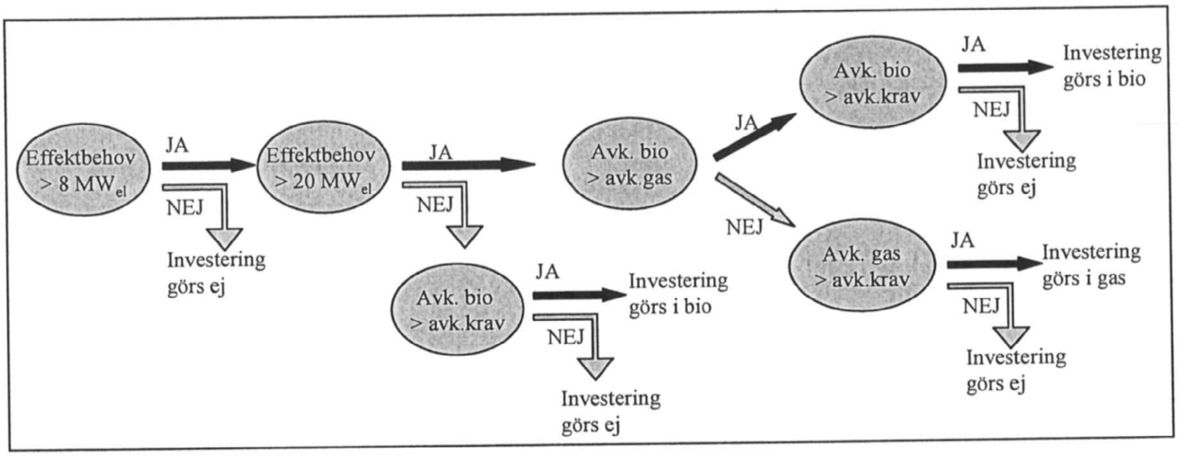
[5] Given current tax rates and electricity prices, heat pumps have a lower priority in the merit order than they did in the past.

50% of the power demand | Waste heat
Waste-fired heat production
Waste-fired cogeneration

Graph 12. Conceptual illustration of priority order.

- The annual costs of each system are calculated in each of the three simulation situations. For the two investment alternatives, system cost reduction is calculated as the difference between the annual variable cost of existing systems and the variable costs of the systems after cogeneration investment. The rate of return on new cogeneration investment is obtained from the ratio between system cost reduction and investment cost. In calculating the return on new cogeneration investment, the reinvestment requirements of existing production systems have also been taken into account.

- A decision to invest in new cogeneration is taken if the minimum size requirement is fulfilled and if the calculated return exceeds the required return. If both new biofuel-fired cogeneration and new CCGT cogeneration meet the requirements, the plant built is that with the highest return. See the illustration below.



Graph 13. The decision-making logic of the model.

Key:

Effektbehov – Power demand; Ja – Yes; Nej – No;
Investering görs ej – No investment
Avk. bio > avk. gas – Return on biofuel > return on gas;
Avk. bio > avk. krav – Return on biofuel > required return
Avk. gas > avk. krav – Return on gas > required return
Investering görs i bio – Investment in biofuels; Investering görs i gas – Investment in gas

- The output data from the model consist of annual electricity and heat production volumes generated after any new investment has been incorporated into an existing system.

- As explained above, the model also includes a number of different assumptions concerning limit conditions. These have been divided into constant and variable parameters.

- Constant parameters are assumptions which are estimable with a certain degree of precision and which remain constant in the simulations. Examples of constant parameters are efficiency, electricity output, CO_2 emissions etc.
- Variable parameters are assumptions about the future concerning electricity prices, fuel prices, certificate prices etc., whose levels are difficult to predict with any high degree of precision. The variable parameters vary in the simulations.

4.1.2. Constant parameters

Efficiencies and power output

The table below shows the efficiency and electricity output values adopted for each technology. The levels selected are intended to reflect the standard amongst existing plants in Sweden and, thus, not the type of technology which is deemed to be the best available.

Technology	**Efficiency**	**Electricity output**	**Fuel**
Waste-fired cogeneration production (flue gas condensation)	100%	0.2	Unsorted combustible waste
Waste-fired heat production (flue gas condensation)	100%	0.0	Unsorted combustible waste
Waste heat	100%	0.0	Purchases from industry
Existing biomass cogeneration production	90%	0.4	Forestry residues
New biomass cogeneration production	90%	0.5	Forestry residues
Existing CCGT production	90%	0.9	Natural gas
New CCGT production	90%	1.0	Natural gas
Existing coal-fired cogeneration production	85%	0.4	Hard coal
Bio-heat production (flue gas condensation)	100%	0.0	Forestry residues
Heat pumps	300%	-0.3	Electricity
Existing gas-fired cogeneration production	85%	0.4	Natural gas
Existing oil-fired cogeneration production	85%	0.4	No. 1 fuel oil
Oil-fired heat production	85%	0.0	No. 1 fuel oil

Graph 14. Technologies, efficiency levels and electricity outputs used in the model.

Green certification

The purchase of green certificates is a requirement for the consumption of electricity in heat pumps. In 2004, the quota requirement was 8.1% of electricity consumption, increasing progressively to 16.9% in 2010 according to the current green certification system.[6] In the model, we have assumed that the long-term quota requirement will be 16.9%. What this means is that we have assumed that the green certification system will remain unchanged for a considerable length of time. Thus, if a decision to invest is made in 2020, the same unchanged conditions of green certification will apply throughout the plant's foreseeable lifetime.

Minimum scale of cogeneration investments

[6] Act (2003:113) on Green Certificates.

We have assumed that investment in cogeneration will focus on systems whose power demand exceeds the minimum size of a cogeneration plant. In the model, the minimum size of a cogeneration plant (measured in MW_{el}) is converted to an equivalent heat output, given a certain electricity output. The minimum plant size we have adopted is based on those cogeneration plants which we believe are commercially viable. The size of such plants is as follows:

- Biomass cogeneration plants – 8 MW_{el}
- CCGT plants – 20 MW_{el}

If the minimum size of biomass cogeneration and CCGT plants is assumed to be 12 MW_{el} instead of 8 or 20 MW_{el}, the scale of cogeneration potential declines by a mere couple of percentage points because of the limited number of investments in MW_{el} in the 8-12 MW_{el} band (see *Graph 17. Power demand per system*).

The need for reinvestment in existing plants

Looking ahead, existing production plants will require reinvestment. In the model, the cost of reinvestment in existing plants has been assumed to be SEK 3 500/kW heat (which applies to all heat and cogeneration facilities). It is assumed that 35% and 70% of the existing plants will require reinvestment by 2015 and 2020 respectively.

Fixed operating and maintenance costs

The additional annual operating and maintenance cost of cogeneration is assumed to amount to 2% of the investment cost. Fixed operating and maintenance costs are the costs of maintenance, staff, insurance etc. The model does not take account of any corresponding costs of existing plants. As we have used the alternative cost calculation, the model is a conservative one because some of the existing plants will probably be phased out and shut down.

Grandfathering of emission allowances

In accordance with Swedish laws, the level up to which emission allowances can be assumed to qualify for grandfathering amounts to:

- 80% for old plants
- 60% for new plants

Taxes (December 2004 taxes)

According to the current tax system, fuel used in heat production is subject to the energy tax and the CO_2 tax. Electricity production, on the other hand, is subject to neither the energy nor the CO_2 taxes.

However, the proportion of the fuel which can be traced back to heat production through allocation is 79% exempt from the CO_2 tax. Moreover, cogeneration production is not subject to energy tax.

The taxes used in the calculation are shown below.

Fuel	**Energy tax**	**CO_2 tax**
Coal	SEK 312/tonne	SEK 2 260/tonne
Oil	SEK 732/m^3	SEK 2 598/m^3
Natural gas	SEK 237/1,000 m^3	SEK 1 946/1 000 m^3
Biofuels	-	-
Electricity consumption	SEK 215/MWh	-

Neither the nitrogen oxide tax nor the sulphur tax has been included in the model. In our opinion, they are negligible in this context.

CO_2 emissions

The CO2 emission levels used in the calculation are those shown in the following table. These have been used in the calculation of the costs of the purchase of emission allowances.

Fuel	**CO_2 emissions**
Coal	93 g/MJ
Oil	74 g/MJ
Natural gas	56 g/MJ
Waste	25 g/MJ

Source: Statistics Sweden, Emission factors for CO_2

4.1.3. Variable parameters

Variable parameters have been divided into three different values: low, reference and high. The low and high values have been produced on the premise that they constitute reasonable and probable levels. They should therefore not be considered to be extreme values. The values for variable parameters have been produced in conjunction with the District Heating Committee. The table below shows the assumptions we have made about variable parameters.

Variable parameter	Low	Ref.	High	Notes
Required return (%)	7.5	8.3	10.3	• Required return assessed by PwC.
Electricity price (SEK/MWh)	200	250	300	• The reference value is based on Nord Pool's 2007 full-year period (EUR 30/MWh), as applied to November 2004 and converted to the 2004 monetary value • The interval has been assessed on the basis of Nord Pool's historical standard deviation for three-year periods and spot prices. In our opinion, a reasonable interval would be one of +/- 20%.
Certificate price (SEK/MWh)	150	200	250	• In November 2004, green certificates were traded at approx. SEK 230/MWh. • However, this level is expected to decline somewhat given that players in the market consider the current levels far too high. The amount of certificates on offer exceeds demand, as some players make savings on certificate, for example. That should make a reference level of SEK 200/MWh a justifiable one. • In our opinion, a reasonable interval would be one of +/- 20%.
Emission allowance price (EUR/tonne)	5	10	15	• In November 2004, the market price was EUR 8-9 /tonne. • Several assessments indicate somewhat higher levels, which are used as the reference value. Given the uncertainties involved, we think that a reasonable interval would be one of +/- 50%.
District heating potential per inhabitant (MWH/person/year)	8.5	9.0	9.5	• The overall heat market for residential and commercial buildings amounts to 90 TWh, which produces 10 MWh/city dweller for Sweden's population of 9 million • A reduction of 5-15% would be reasonable because not every facility can be integrated with district heating.

Variable production costs (fuel and variable operating and maintenance costs)[7]

	Low	Ref.	High	•
Biofuels (SEK/MWh)	135	150	165	• The alternative reference value is based on a price of SEK 130/MWh (Electricity from new plants, 2003). • A surcharge of SEK 20/MWh on variable operating and maintenance costs (Electricity from new plants, 2003) • In our opinion, an interval of +/- 10% would be a reasonable one.
Natural gas (SEK/MWh)	120	150	180	• The alternative reference value is based on a price of SEK 140/MWh (Electricity from new plants, 2003). • A surcharge of SEK 10/MWh on variable operating and maintenance costs (Electricity from new plants, 2003). • In our opinion, an interval of +/- 20% would be a reasonable one.
Oil (SEK/MWh)	200	250	300	• The alternative high value is based on the November market price of No. 1 fuel oil. The reference value alternative is at the level applicable during the 2000-2003 period. • A surcharge of SEK 10/MWh on variable operating and maintenance costs (Electricity from new plants, 2003).
Coal (SEK/MWh)	60	75	90	• The coal price of the alternative reference value is assumed to be SEK 45/MWh (based on USD 50/tonne). • A surcharge of SEK 30/MWh on operating and maintenance costs (Electricity from new plants, 2003). • However, in our opinion, an interval of +/- 20% would be a reasonable for the coal price.

[7] The prices of waste heat and waste do not vary in the model. These two fuels are at the high end of themerit order (which is fixed), which is why their prices do not have an impact on cogeneration potential. However, a variable production cost of SEK 125/MWh has been assumed for waste heat for the purposes of calculating system costs. A variable production cost of - SEK 100/MWh has been assumed for waste (the waste acceptance charge minus variable operating and maintenance costs).

Investment in cogeneration

	Low	Ref.	High	
Biomass cogeneration (SEK/kWh$_{el}$)				The following applies to both biomass cogeneration and CCGT cogeneration: • Investment cost/kW is assumed to be linearly dependent on the size of the plant. • The values used here are based on "Electricity from new plants, 2003". • We have not observed any expected productivity improvement which could lead to price reductions. We have received indications from various quarters that such an improvement has not taken place, from a historical perspective, at least. So far, it has been factors other than productivity improvement that have determined prices used by plants. • In our opinion, an interval of +/-20 would be a reasonable one.
10 MW$_{el}$	17 000	21 200	25 500	
30 MW$_{el}$	13 000	16 400	20 000	
>80 MW$_{el}$	9 500	12 000	14 500	
CCGTs (SEK/kWh$_{el}$)				
40 MW$_{el}$	6 400	8 000	9 600	
150 MW$_{el}$	5 200	6 500	7 800	

In total, there are nine variable parameters. Although some of these are interdependent, we have not carried out a correlation analysis, as that falls outside the remit of our task. However, we have assumed that the prices of fossil fuels, i.e. natural gas, oil and coal, are correlated. In our simulations, we have resolved this issue by assuming that whether oil and coal prices are high or low depends on whether the price of natural gas is high or low. By the same token, we have assumed that the investment costs per kW$_{el}$ for biomass cogeneration plants and CCGTs are correlated.

4.1.4. Limitations of the model

Our model relies on a degree of simplification, which reduces the precision of the assessment of potential:

The first limitation is that we have assumed that the priority order will remain unchanged irrespective of fuel prices etc. If this were a more accurate model, we would need to change the priority order to reflect major relative price changes. We are of the opinion that the existing priority order reflects a true and fair picture of the current conditions and a somewhat higher electricity price than the current one. What this limitation implies is that no new cogeneration should be built on the back of existing waste heat or existing waste incineration.

The second limitation arises from our assumption that biofuels will be available in unlimited quantities throughout the country, in contrast to natural gas, access to which is only available in some municipalities. In real terms, the three large urban areas in Sweden (Stockholm, Gothenburg and Malmö) could face capacity restrictions in terms of new biofuel-fired cogeneration because of difficulties in fuel logistics and the lack of access to suitable production sites. It is possible that, particularly in some parts of the Stockholm region, new cogeneration will only be viable in the short term if natural gas is used as a fuel. Furthermore, the prices of biofuels could change if there is a significant change in demand. The same pricing logic could also apply to natural gas.

The third limitation is that cogeneration potential is based on comparisons of the economic impact of changes in the existing production line-up. We have not carried out any checks as to whether or not it might be a more profitable solution to invest in an alternative production technology.

The fourth limitation is that we have not calculated implementation periods, which is to say that we have not taken into account any practical limitations, such as the process involved in obtaining an environmental permit, purchasing, construction, start-up etc.

The fifth limitation is that we have not considered the fact that the conditions of individual urban areas and/or investments might differ from the simplified assumptions and generalisations we have used in the calculation of the economic potential. This means that the present report may contain inaccuracies as regards individual urban areas and plants.

4.2. The results

In the following sections we provide results of the calculations of potential. First of all, we look at a reference scenario and then provide results of simulations which take into account variations in variable parameters.

In Appendix I (*A sensitivity analysis of the potential for cogeneration within district heating*), we show the sensitivity of the results to variation in certain parameters.

4.2.1. Reference scenario

We have produced a reference scenario based on the current situation (end of 2004) concerning various municipalities' access to natural gas, current connecting pipelines and the assumption that the current tax and green certification system will remain unchanged. In the reference scenario, reference values are allocated to variable parameters.

The result of the reference scenario for 2015 is shown below. We have chosen to define cogeneration potential as the net electricity balance, which means total gross electricity production, net of electricity used to power heat pumps and other operating electricity. In this report, the term "cogeneration potential" is taken to be synonymous with "net electricity balance". We have chosen this definition because it reflects the portion of electricity production which the district heating sector can supply net to the electricity system.

Cogeneration potential 2015		**Reference scenario**	
New production capacity of cogeneration	Biofuels	2 386	MW_{el}
	CCGT	46	MW_{el}
	Total	2 431	MW_{el}
Electricity production, new capacity	Biofuels	10.8	TWh
	CCGT	0.2	TWh
	Total	11.0	TWh
Electricity production, existing capacity	Biofuels	4.4	TWh
	Coal	0.3	TWh
	Oil	0.1	TWh
	Gas	0.5	TWh
	Waste	1.4	TWh
	Total	6.6	TWh
Total electricity production, gross		17.6	TWh
Electricity used to power heat pumps		-0.2	TWh
Other operating electricity		-1.8	TWh
Net electricity balance, TWh		**15.6**	**TWh**

Graph 15. Cogeneration potential according to the reference scenario. Other operating electricity has been calculated on a flat-rate basis as 3% of the total heat production.

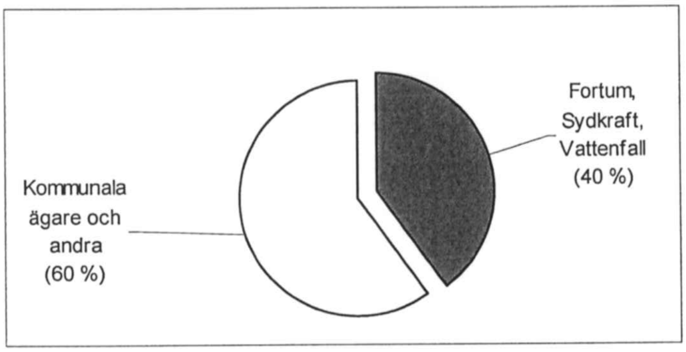
In the 2015 reference scenario, the economic cogeneration potential has been calculated at approximately 15.6 TWh of the net balance of 2015, or 17.6 TWh of total gross electricity production. By way of comparison, Statistics Sweden[8] puts the 2004 level of power generation within the district heating sector at 6.8 TWh (which corresponds to gross electricity production, according to the definitions used in this report).

The 2015 reference scenario envisages investment in new cogeneration capacity of 2 431 MW_{el}. By way of comparison, in December 2003, the installed power generation capacity of the district heating sector stood at 2 572 MW_{el}.[9]

Ninety-seven percent of the potential within *Electricity production, new capacity* in the 2015 reference scenario lies in biomass cogeneration. This leaves a very limited scope for expansion of CCGT technology in Sweden. The primary reason for this is that, according to the assumptions used in this model, investment in biomass cogeneration is much more profitable than investment in CCGT because of the green certification system.

Currently, two CCGT plants are in the process of being designed or planned in Sweden. One of these is the Rya plant in Gothenburg, on whose construction a final decision has already been made. In the model, the Rya plant has been included as an existing CCGT plant. However, the model also assumes that Gothenburg will invest in a biomass cogeneration plant which will replace the Rya plant. The second CCGT plant at the planning stage is the Öresund plant in Malmö. However, the model assumes that Malmö will also invest in biomass cogeneration. The ways in which these two systems are treated in the model show that the CCGTs will find it difficult to compete with biomass cogeneration under the current assumptions and conditions. This may be explained by the strictness of current instruments, primarily green certification.

Forty percent of the estimated economic cogeneration potential within *Electricity production, new capacity*, which is shown in graph 15 above, lies with systems controlled by one of the three large energy companies (Vattenfall, Sydkraft and Fortum). The largest portion, some 60%, lies with energy companies in primarily municipal ownership.



Municipal owners and others (60%); Fortum, Sydkraft, Vattenfall (40%)

Graph 16. Distribution of cogeneration potential across various owners

A detailed analysis of the reference scenario is provided below.

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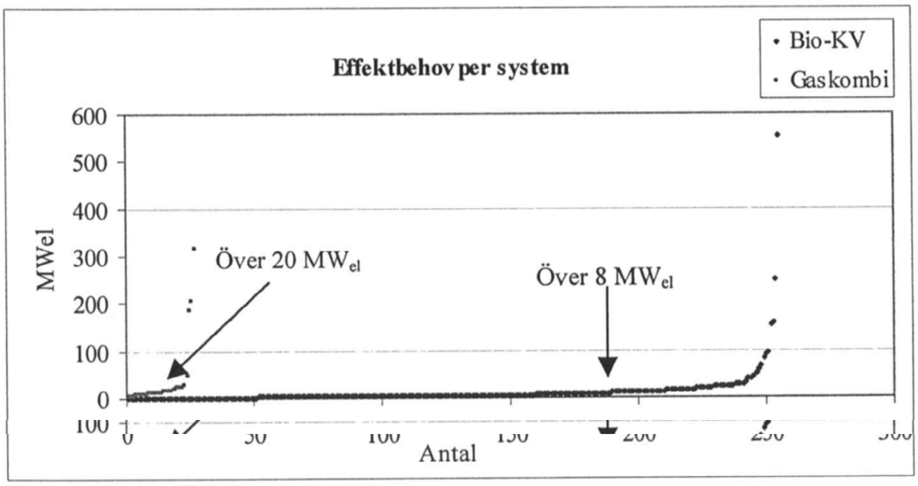
[8] www.scb.se, Electricity supply, month by month

[9] Source: Nordel

Power demand per plant

The graph below shows the power demand of plants included in the reference scenario. Power demand is defined as the capacity increase per system, expressed in MW_{el}, which is required to cover each system's heat demand, given increased market penetration. Since electricity output is different for CCGT and biomass cogeneration, two separate heat demand curves have been drawn for CCGT and biomass cogeneration.



Power demand per system

Biomass cogeneration, CCGT

Above 20 MW_{el}; Above 8 MW_{el}; Antal (Number)

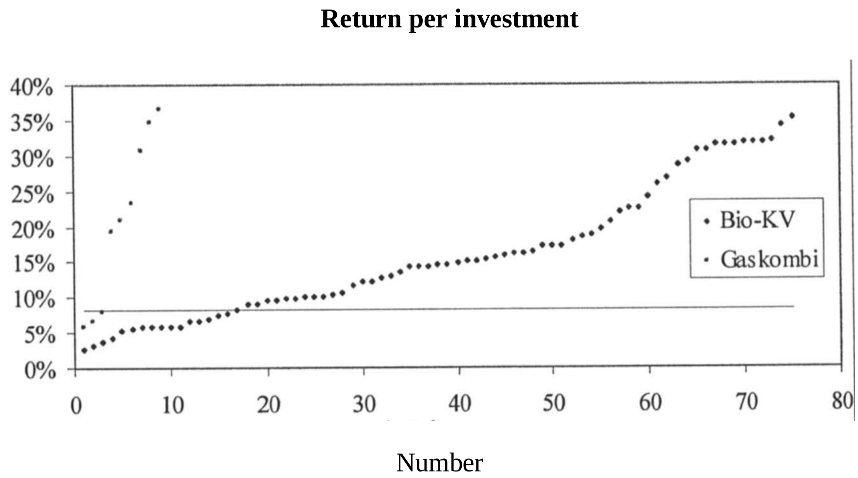
Graph 17. Power demand per system

A total of 264 systems have been included in the analysis. The power demand of only some of these systems exceeds the minimum required for investment in biomass cogeneration or CCGT.

- The power demand of 75 of the 264 systems included exceeds 8 MW_{el}. However, this corresponds to 81% of the systems' overall power demand.
- The power demand of 9 of the 27 systems which have access to natural gas exceeds 20 MW_{el}. This corresponds to 77% of the systems' overall power demand.

Return per investment

The graph below shows return per investment.

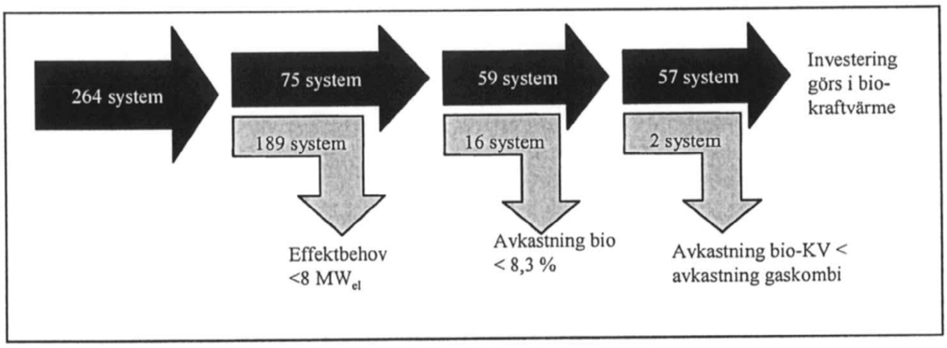


Graph 18. Return pert investment. The horizontal black line marks the required return of 8.3%.

This graph shows that, of the 75 systems whose power demand exceeds 8 MW_{el}, only 16 biomass cogeneration investments have a profitability rate which falls below the required return of 8.3%.

We can also see that, of the 9 systems whose power demand exceeds 20 MW_{el}, only 3 CCGTs have a profitability rate which falls below the required return of 8.3%.

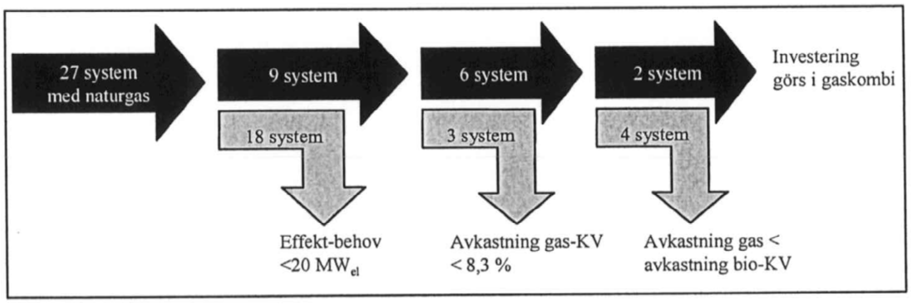
In the following section, we provide a summary of the decision-making process for biomass cogeneration and CCGT investments in the baseline scenario. From this illustration, it follows that biomass cogeneration investment is more profitable than CCGT in the majority of cases where there is access to natural gas and scope for CCGT investment.



Key:

Upper row: 264 systems; 75 systems; 59 systems; 57 systems; Investment in biomass cogeneration
Middle row: 189 systems, 16 systems, 2 systems
Lower row: Power demand < 8 MW_{el}; Return on bio-fuels < 8.3%; Return on biomass cogeneration < return on CCGT

Graph 19. Investment in biomass cogeneration in the model's decision-making process. Of the 264 systems included in the model, 75 systems have a power demand exceeding 8 MW_{el}. Of these 75 systems, 59 systems have a return on biomass cogeneration investment which exceeds the required return of 8.3%. Of these 59 systems, there are 2 biomass cogeneration investments which are not viable because investment in CCGT is more profitable. In total, biomass cogeneration investment has been made in 57 systems.



Key:
Upper row: 27 natural gas-fired systems; 9 systems; 6 systems; 2 systems; Investment in CCGT
Middle row: 18 systems; 3 systems; 4 systems
Lower row: Power demand < 20 MW_{el}; Return on CCGT < 8.3%; Return on gas < return on biomass cogeneration

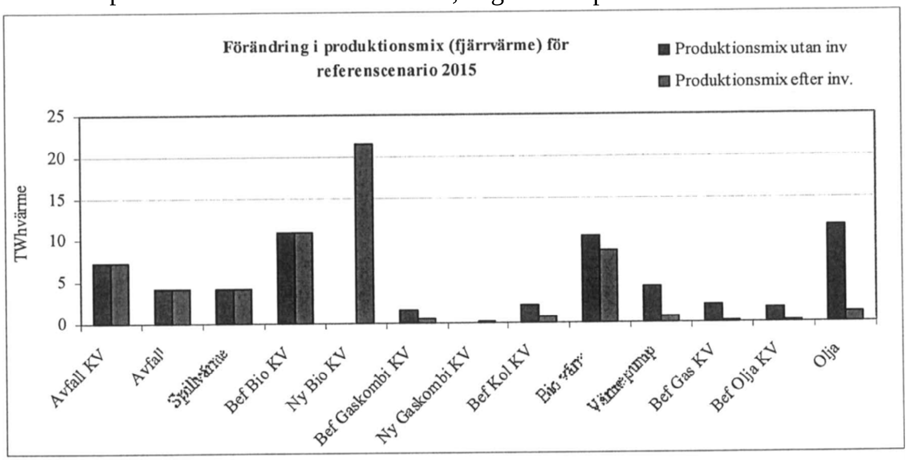
Graph 20. Investment in CCGT in the model's decision-making process. Of the 27 systems included in the model which have access to natural gas, there are 9 systems whose power demand exceeds 20 MW_{el}. Of these 9 systems, there are 6 systems whose return on CCGT investment exceeds the required return of 8.3%. Of these 6 systems, there are 4 CCGTs which are not viable because return on biomass cogeneration investment is more profitable. In total, biomass cogeneration investment has been made in 2 systems.

The reference scenario for 2015 – Variations in the production mix

The following graph illustrates variations in the production mix within the reference scenario, as compared to the existing scenario (including growth by 2015) in which no investment in cogeneration has been made. New biomass cogeneration and CCGT mainly replace solid fuel-fired heat production, heat pumps, existing gas-fired cogeneration, existing oil-fired cogeneration and oil-fired heat production. The graph suggests that there will be no change to the amount of heat production from waste-fired cogeneration, waste-fired heat production, waste heat or existing biomass cogeneration (which is one of the basic assumptions of the model).

Variations in the (district heating) production mix for the 2015 reference scenario

Left bar – production mix after investment; Right bar – production mix without investment



X axis – Waste-fired cogeneration; Waste; Waste heat; Existing biomass cogeneration; New biomass cogeneration; Existing CCGT cogeneration; New CCGT cogeneration; Existing coal-fired cogeneration; Biomass-fired heat production; Heat pumps; Existing gas-fired cogeneration; Existing oil-fired cogeneration; Oil
Y axis – TWh heat

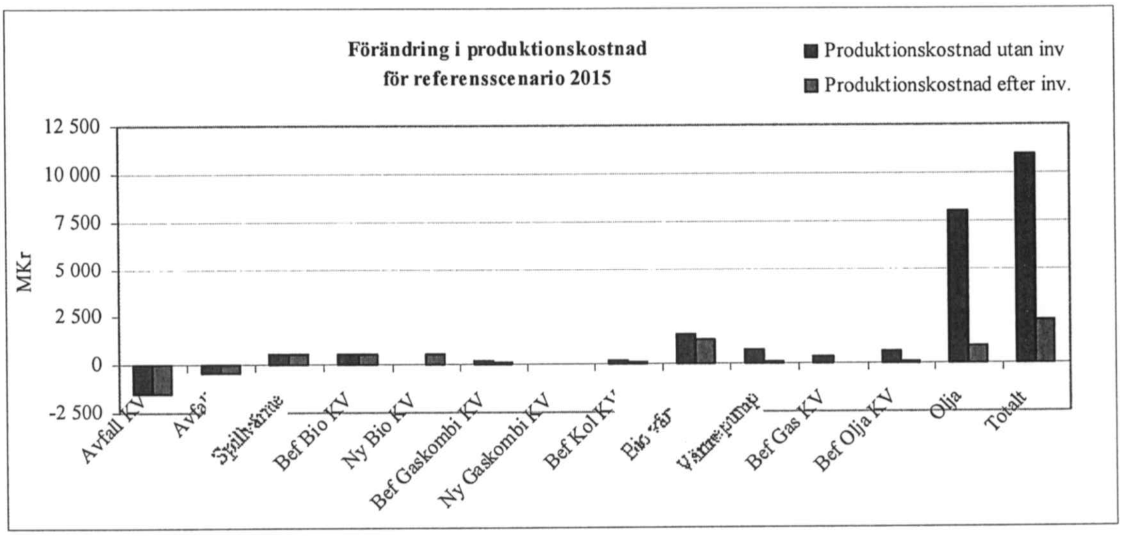
Graph 21. Variations in the 2015 (district heating) production mix for systems without investment in cogeneration and systems after investment in cogeneration

The 2015 reference scenario – Variations in production costs

The graph below shows variations in production costs in the reference scenario. Production costs are derived from variable production costs net of income from electricity sales.

Variations in the production costs for the 2015 reference scenario

Left bar - Production costs after investment; Right bar – Production mix without investment



X axis – Waste-fired cogeneration; Waste; Waste heat; Existing biomass cogeneration; New biomass cogeneration; Existing CCGT cogeneration; New CCGT cogeneration; Existing coal-fired cogeneration; Biomass-fired heat production; Heat pumps; Existing gas-fired cogeneration; Existing oil-fired cogeneration; Oil; Total
Y axis – SEK million

Graph 22. Variations in the 2015 variable production costs (net of income from electricity sales) for systems without investment and systems after investment in cogeneration.

This graph suggests that energy producers stand to make major savings by replacing expensive oil production with biomass cogeneration. The total savings for producers come to nearly SEK 9 billion, if variable production costs are accepted.

Rough investment estimates for 2010, 2015 and 2020

Based on the assumptions described above, the investment costs needed to implement cogeneration potential have been calculated.

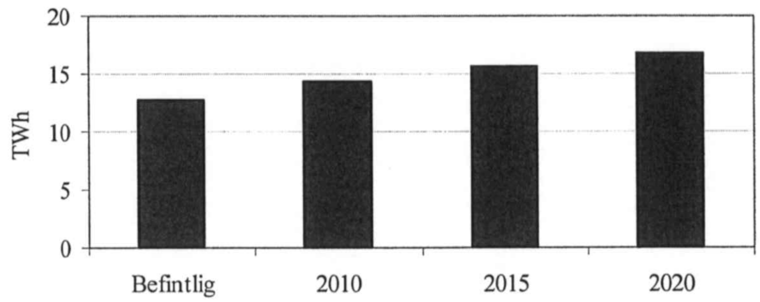
Accumulated investments	2010	2015	2020
SEK billion			
Biomass cogeneration	26-32	30-39	35-45
CCGT	<0.1	0.3-0.5	0.5-1

Graph 23. Accumulated investments in cogeneration for 2010, 2015 and 2020.

Cogeneration potential for the 2010-2020 reference scenario

The graph below illustrates cogeneration potential for the 2010-2020 period and today's cogeneration potential. "Existing cogeneration potential" means the potential of existing district heating systems (i.e. measured at the 2001 base-year volume).

Cogeneration potential of the reference scenario (net electricity balance)



X axis: Existing; 2010; 2015; 2020
Y axis: TWh

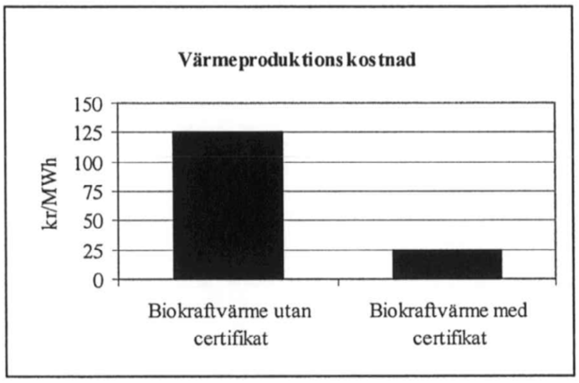
Graph 24. The graph shows the cogeneration potential of existing plants and the cogeneration potential for 2010, 2015 and 2020. "Existing potential" means a situation involving no increase in district heating systems' heat sales

The graph above suggests that the majority of cogeneration potential is already available in existing systems. The existing potential is inherent in the possibility of replacing existing, expensive production plants with less expensive biomass cogeneration plants. Such biomass cogeneration plants have economic advantages, thanks to relatively low biofuel costs and the income which they generate from green certificate sales. In the reference scenario, the cogeneration potential of the existing district heating system amounts to nearly 13 TWh, which constitutes approximately 75% of the accumulated total potential in 2020. Therefore, future growth of district heat deliveries accounts for a minor proportion of the total cogeneration potential.

The fact that significant cogeneration potential may be found in existing district heating systems, and that such potential is not merely dependent on expansion of district heating networks, may appear to be a somewhat surprising result. The primary reason for this is that the economic conditions for biofuel-based cogeneration improved radically with the introduction of the green certification system in 2003. Green certification increases dramatically the profitability of biomass cogeneration investments.

Below, we illustrate the impact of green certification on the heat production costs of a biomass cogeneration plant. "Heat production cost" is defined as fuel costs adjusted for losses and net of income from electricity sales.

Heat production costs



X axis – Biomass cogeneration without certification; Biomass with certification
Y axis – SEK/MWh

Graph 25. Illustration of the heat production costs of biomass cogeneration with and without certification.

4.2.2. Simulations and scenario analysis

In addition to estimating the potential for cogeneration in the form of a reference scenario, our task also involved carrying out simulations, so that we were able to examine how the potentials will be affected by variation in parameters.

The simulation is based on a large number of calculations involving various combinations of variable parameter levels (as explained in section 4.1.3.). In the following section, we provide the results of simulations for 2010, 2015 and 2020, which form the basis for estimating the economic cogeneration potential.

Below, we provide details of the scenarios studied. For space reasons, we have only illustrated the results of the scenario for 2015.

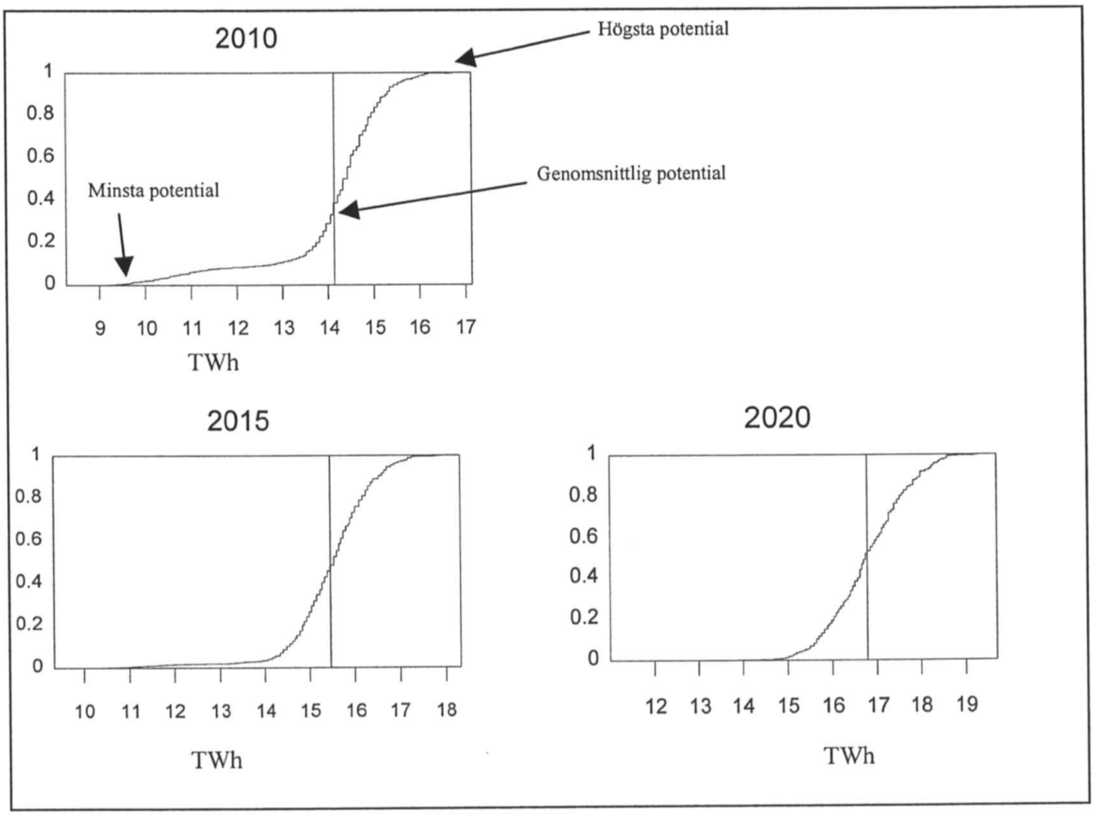
- The scrapping of green certification from 2010 onwards
- Introduction of a concession requirement for integrable systems
- Establishment of a natural gas pipeline extending to Mälardalen and Gävle
- The scrapping of the CO_2 tax on cogeneration production
- The scrapping of emissions trading
- Combined variation of basic assumptions

4.2.2.1 Baseline cogeneration potential

The present simulations are based on existing market conditions.

The simulations produce a number of different calculation outcomes, depending on the value of the given cogeneration potential. These calculation outcomes are sorted by size and an S-shaped curve (see the graphs below) is obtained. The horizontal axis indicates the value of cogeneration potential (net electricity balance). Calculation outcomes which correspond to the least favourable levels of variable parameters are shown at the far left of the S curve. Conversely, calculation outcomes which correspond to the most favourable levels of variable parameters are shown at the far right of the S curve. All other calculation outcomes represent various intermediate points on the S curve.

The vertical line running down the middle of the graph indicates the weighted average of all calculation outcomes.



Key:
Minsta potential – Lowest potential
Genomsnittlig potential – Average potential
Högsta potential – Highest potential

Graph 26. The graphs above show cogeneration potential for 2010, 2015 and 2020. The horizontal axis shows cogeneration potential (in TWh) and the vertical axis shows the number of calculation outcomes (out of the total number of calculation outcomes).

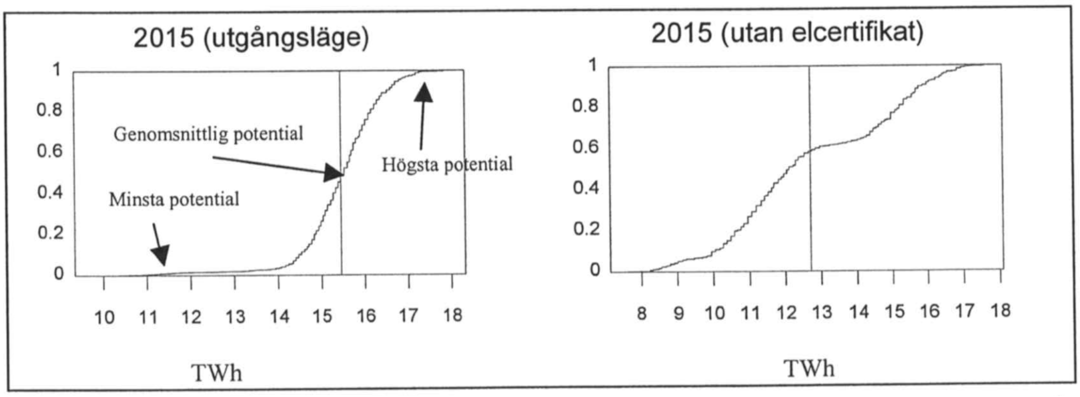
The simulations estimate the economic cogeneration potential of district heating systems as follows:

- 2010 – over 14 TWh with an interval of 13.3-15.3 TWh
- 2015 – approx. 15.5 TWh with an interval of 14.6-16.6 TWh
- 2020 – approx. 17 TWh with an interval of 15.6-18 TWh

It can be seen that the distribution of calculation outcomes for 2010 is greater than that for 2015 or 2020. This is primarily because of our assumption that some of the existing plants will require reinvestment over time. The need for reinvestment will be greater in 2020 than in 2010, which is why this alternative form of reinvestment has increased the profitability figures of cogeneration investment in a greater number of calculation outcomes in 2020 than in 2010.

4.2.2.2. Scrapping of the green certification system

The graph below illustrates baseline cogeneration potential and cogeneration potential in a situation where the green certification system is scrapped from 2010 onwards. The calculation of income from electricity production in this scenario is based on the assumption that no payment will therefore be made for green certificates.



Key:
2015 (baseline); 2015 (without green certification)
Lowest potential, Average potential, Highest potential

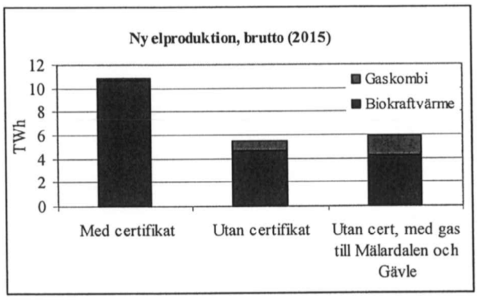
Graph 27. The graphs above show cogeneration potential for 2015, both for the baseline scenario and one without green certification. The horizontal axis shows cogeneration potential (in TWh) and the vertical axis shows the number of calculation outcomes (out of the total number of calculation outcomes). In the scenario without green certification, the expected value of cogeneration potential declines by 2.5 TWh compared to the baseline scenario.

In a scenario without green certification, the potential declines from 15 TWh to around 12.5 TWh. Compared to the baseline, the capacity of new cogeneration is halved, whereas the capacity of new CCGT cogeneration which is under construction undergoes a threefold increase (albeit from a low level). The net effect of this is a drop in potential of 2.5 TWh.

The distribution of calculation outcomes in the scenario without green certification is greater than in the baseline scenario. This is due to the fact that return on a number of investments ends up being “close to” the required return and is therefore more sensitive to variation in the variable parameters.

By way of complement to the baseline scenario, we also illustrate the scenario without green certification, but with the assumption that natural gas will be available in Mälardalen and Gävle. The following graph illustrates the impact of the distribution of new electricity production capacity between biomass cogeneration and CCGT. What it suggests is that, although the potential within biofuel will be halved, alternative investment in CCGT will provide some counterbalance.

New electricity production, gross (2015)



Bottom bar – Biomass cogeneration; Top bar – CCGT
X axis: With certification; Without certification; Without certification, but with Mälardalen and Gävle having access to natural gas
Y axis: TWh

Graph 28. Distribution of new electricity production, gross (2015) between CCGT and biomass cogeneration. The three bars illustrate three different scenarios: those with and without certification, and a scenario without certification, but with Mälardalen and Gävle having access to natural gas.

It should be noted that, if the green certification system is scrapped from 2010 onwards, cogeneration potential will be considerably more sensitive to variations in the other basic assumptions, such as the concession requirement imposed on adjacent systems, the CO_2 tax and the allocation of emission allowances. This is explained in greater detail in section 4.2.2.7.

4.2.2.3 Concession requirement imposed on integrable systems

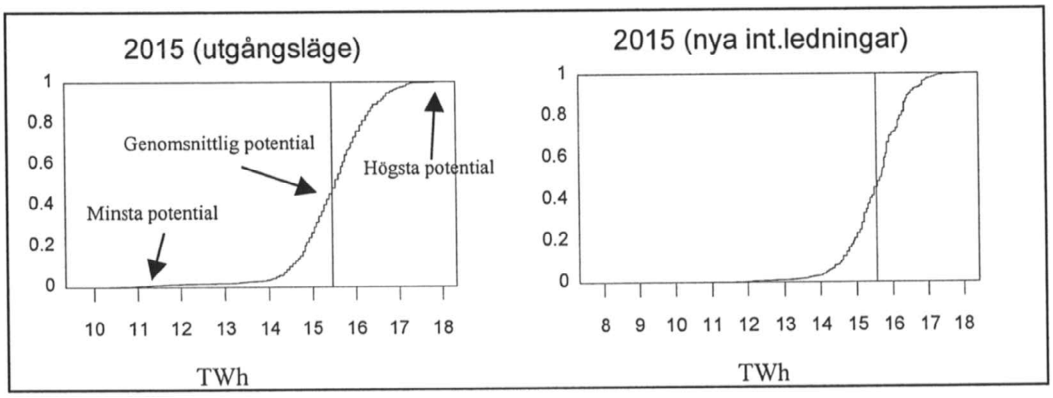
Due to technical and practical reasons, we have assumed that adjacent systems can be interconnected. When two systems are integrated in the model, the entire production capacity of the integrated systems is used across their entire heating infrastructure.[10] The systems assumed to be capable of interconnection are shown in the table below.

Municipalities assumed to have the potential for eventual integration					
Danderyd	with	Stockholm	Nora	with	Örebro
Falkenberg	with	Halmstad	Sandviken	with	Gävle
Falun	with	Borlänge	Solna	with	Stockholm
Hammarö	with	Karlstad	Staffanstorp	with	Malmö
Haninge	with	Stockholm	Svalöv	with	Malmö
Helsingborg	with	Malmö	Södertälje	with	Stockholm
Höganäs	with	Malmö	Timrå	with	Sundsvall
Kungsbacka	with	Gothenburg	Trelleborg	with	Malmö
Kungälv	with	Gothenburg	Trollhättan	with	Uddevalla
Kävlinge	with	Malmö	Täby	with	Stockholm
Köping	with	Västerås	Vallentuna	with	Stockholm
Laholm	with	Halmstad	Varberg	with	Halmstad
Lerum	with	Gothenburg	Vellinge	with	Malmö
Lund	with	Malmö	Ängelholm	with	Malmö
Nacka	with	Stockholm			

Graph 29. Municipalities which are currently not integrated, but which are assumed to have the potential to eventually be integrated. As stated earlier, the three networks in Stockholm have, from the outset, been treated as a single network.

The following graph shows baseline cogeneration potential and cogeneration potential in a hypothetical scenario in which new connecting pipelines are installed.

[10] We assume that service life will remain unchanged if adjacent systems are integrated. A slight increase in service life is possible in real terms, because more pipelines produce greater distribution losses if service life is long.



Key:
2015 (baseline); 2015 (new connecting pipelines)
Lowest potential; Average potential; Highest potential

Graph 30. The graphs above show cogeneration potential for 2015, both for the baseline scenario and for the hypothetical scenario involving new connecting pipelines. The horizontal axis shows cogeneration potential (in TWh) and the vertical one shows the number of calculation outcomes (out of the total number of calculation outcomes). There is no major impact on the expected value of cogeneration potential in the hypothetical scenario involving new connecting pipelines.

The result of the simulations shows that the potential is not significantly affected in a situation in which there are a greater number of connecting pipelines. The main explanation for this is that urban areas with a capacity for integration have scope for investment in cogeneration, whether or not their networks are integrated with adjacent networks. However, there are a small number of systems which could exceed the minimum requirement for cogeneration investment if they were fitted with connecting pipelines, even though their own power demand is not sufficient to warrant investment in cogeneration. However, their impact on the increase of cogeneration potential is marginal.

Connecting pipelines would not have any appreciable effect on the distribution of cogeneration potential between biomass cogeneration and CCGT, providing the green certification system remains in place after 2010.

If, on the other hand, the green certification system is scrapped in 2010, cogeneration potential will be considerably more sensitive to the introduction of a concession requirement for integrable systems. Cogeneration potential **increases** if the concession requirement is introduced, assuming that the green certification system is scrapped in 2010. This is explained in greater detail in section 4.2.2.7.

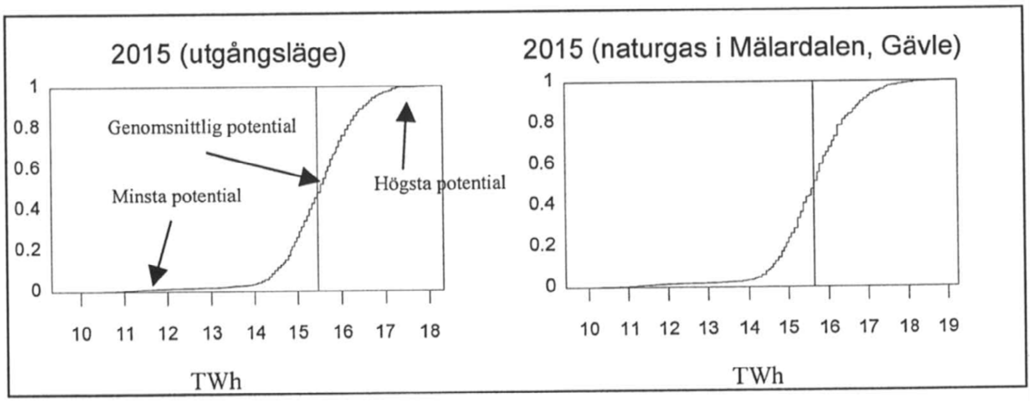
4.2.2.4 Natural gas pipeline extending to Mälardalen and Gävle in 2015

In a hypothetical scenario in which Mälardalen and the Gävle area gain access to natural gas, we have assumed that the following municipalities will have access to natural gas:

Municipalities with access to natural gas if Mälardalen and Gävle are granted access to natural gas			
Aneby	Hofors	Sala	Täby
Askersund	Håbo	Sandviken	Upplands Bro
Botkyrka	Jönköping	Sigtuna	Upplands Väsby
Danderyd	Katrineholm	Sollentuna	Uppsala
Enköping	Kumla	Solna	Vadstena
Eskilstuna	Linköping	Stockholm	Vaggeryd
Finspång	Mjölby	Strängnäs	Västerås
Flen	Motala	Sundbyberg	Älvkarleby
Gnesta	Norrköping	Södertälje	Ödeshög
Gävle	Nyköping	Tierp	Örebro
Hallsberg	Oxelösund	Tranås	

Graph 31. Municipalities assumed to have access to natural gas if Mälardalen and Gävle are granted access to natural gas

In the following graph, we show cogeneration potential for the baseline scenario and the hypothetical scenario in which Mälardalen and Gävle gain access to natural gas.



Key:
2015 (baseline); 2015 (natural gas for Mälardalen and Gävle)
Lowest potential; Average potential; Highest potential

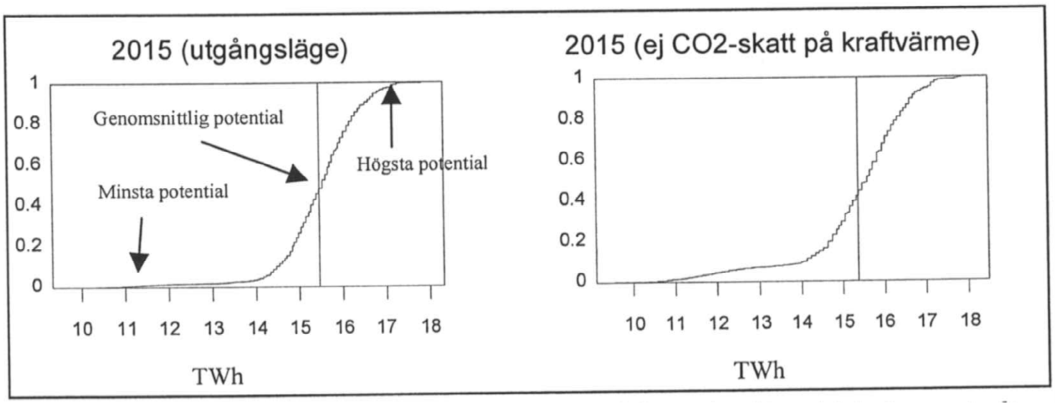
Graph 32. The graphs above show cogeneration potential for 2015, both for the baseline scenario and the hypothetical scenario in which Mälardalen and Gävle gain access to natural gas. The horizontal axis shows cogeneration potential (in TWh) and the vertical axis shows the number of calculation outcomes (out of the total number of calculation outcomes). There is no major impact on the expected value of cogeneration potential in the hypothetical scenario in which Mälardalen and Gävle gain access to natural gas.

The result of the simulations shows that cogeneration potential is not significantly affected in a situation in which Mälardalen and Gävle gain access to natural gas. What does happen, however, is that the potential shifts to some extent from biomass cogeneration to CCGT cogeneration. The doubling of the CCGT potential is to the detriment of the biomass cogeneration potential. The explanation for why expansion of a natural gas network has only a limited impact on the potential is that, in the majority of cases in the model, investment in biomass cogeneration is more profitable. It should be noted, however, that an expanded natural gas network could trigger a drop in biofuel prices in some regions and impact on other prices and variables. The model does not take account of the impact of this.

4.2.2.5. Scrapping of the CO2 tax on cogeneration production

Under the current tax system, any heat produced through cogeneration (and derived through allocation) is subject to 21% of the applicable CO_2 tax. Electricity production is not subject to the CO_2 tax.

The graphs below illustrate the impact of cogeneration being totally exempt from the CO_2 tax. Such a tax reduction would benefit, not only CCGTs, but also existing coal, oil and gas-fired cogeneration. As a result, investment in biomass cogeneration would become less profitable.



Key
2015 (baseline); 2015 (no CO2 tax on cogeneration)
Lowest potential; Average potential; Highest potential

Graph 33. The graphs above show cogeneration potential for 2015, both for the baseline scenario and for a hypothetical scenario where cogeneration production is totally exempt from the CO_2 tax. The horizontal axis shows cogeneration potential (in TWh) and the vertical axis shows the number of calculation outcomes (out of the total number of calculation outcomes). There is no major impact on the expected value of cogeneration potential in the scenario in which cogeneration production is totally exempt from the CO_2 tax.

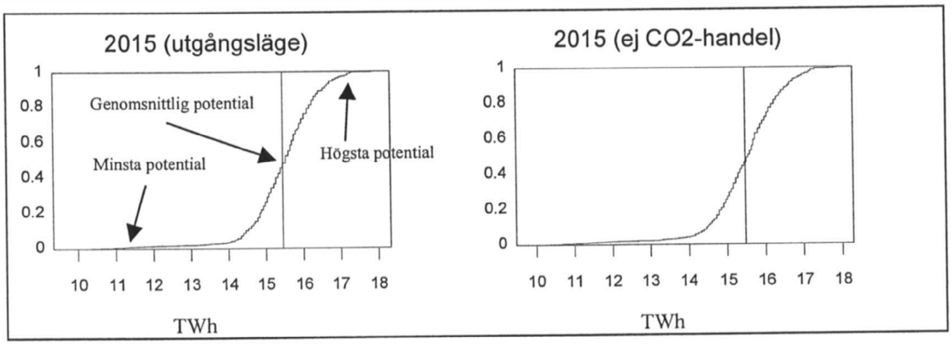
In the scenario in which the CO_2 tax on cogeneration is scrapped, cogeneration potential increases only marginally. However, there is a shift from investment in biomass cogeneration to investment in CCGT, because the benefits of investing in CCGT are greater if the CO_2 tax is scrapped. A converse effect of the scrapping of the CO_2 tax is that existing fossil fuel-fired cogeneration becomes cheaper, which reduces any savings likely to be made from new investment in cogeneration. The end result is that some investments in biomass cogeneration will be unable to meet the profitability requirement.

If the green certification system is scrapped in 2010, cogeneration potential will be considerably more sensitive to the scrapping of the CO_2 tax and the allocation of emission allowances. Cogeneration potential **increases** significantly if the CO_2 tax is scrapped and if emission allowances are grandfathered to new plants (providing the green certification system is scrapped in 2010). This is explained in greater detail in section 4.2.2.7.

4.2.2.6 Scrapping of emissions trading

In the model, CO_2 emissions are subject to the costs of purchase of emission allowances.

In the following section, we illustrate the impact of the potential scrapping of emissions trading. The impact of this is marginal.



2015 (baseline); 2015 (CO_2 trading scrapped)
Lowest potential; Average potential; Highest potential

Graph 34. The graphs above show cogeneration potential for 2015, both for the baseline scenario and for a hypothetical scenario in which CO_2 trading is scrapped. The horizontal axis shows cogeneration potential (in TWh) and the vertical one shows the number of calculation outcomes (out of the total number of calculation outcomes). There is no major impact on the expected value of cogeneration potential in the scenario in which CO_2 trading is scrapped.

If the green certification system is scrapped in 2010, cogeneration potential will be more sensitive to emissions trading. Cogeneration potential declines marginally if emissions trading is scrapped (providing the green certification system is scrapped in 2010).

4.2.2.7. Combined variations of basic assumptions

As explained above, the single most important basic assumption for cogeneration potential is whether the green certification system is maintained beyond 2010 or scrapped. Cogeneration potential drops from 15.6 TWh if the green certification system is maintained indefinitely to 12.5 TWh if it is scrapped in 2010.

On the other hand, if the green certification system is scrapped in 2010, cogeneration potential will be considerably more sensitive to any variation in the other basic assumptions, such as the concession requirement on integrable systems, the CO_2 tax and the allocation of emission allowances. We provide below an outline of some examples of the impact of combined variations in the basic assumptions.

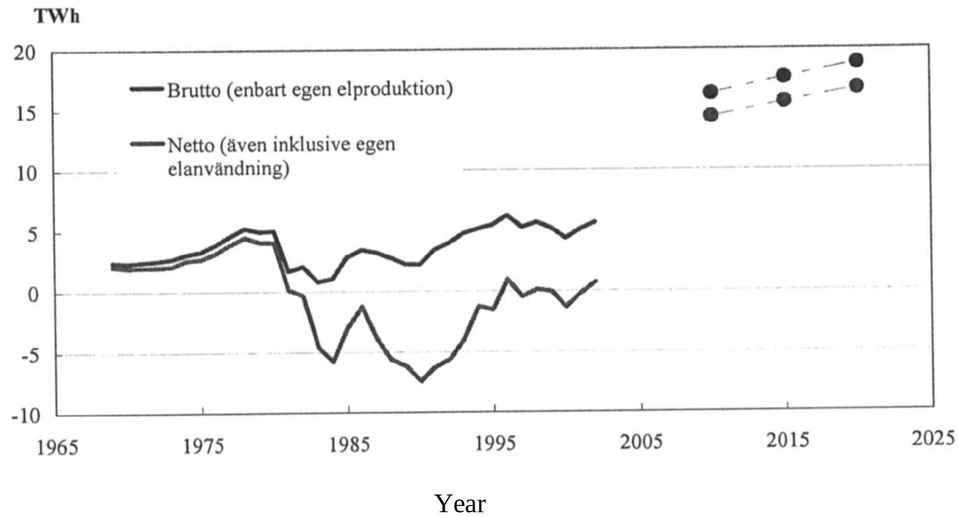
- The green certification system is scrapped in 2010 and the concession requirement is imposed on integrable systems.
- Cogeneration potential increases by nearly 2 TWh from the 12.5 TWh projected in the reference scenario
- The green certification system is scrapped in 2010, the concession requirement is imposed on integrable systems, the CO_2 tax is scrapped on cogeneration production and emission allowances are grandfathered to new plants.
- Cogeneration potential **increases** by some 4 TWh from the 12.5 TWh projected in the reference scenario.

4.3 Concluding discussion

4.3.1. The cogeneration potential of district heating systems

We have relied on the District Heating Consultancy Bureau's model of Sweden's district heating market in estimating cogeneration potential for 2010, 2015 and 2020. The graph below shows the potential of cogeneration within district heating and historical cogeneration production (measured in gross and net electricity balance).

Cogeneration within district heating



Gross (own electricity production only); Net (including own electricity consumption)

Graph 35. Gross and net historical cogeneration potential for the 1970-2003 period and estimated cogeneration potential if 14TWh is achieved in 2010, 15.5 TWh in 2015 and 17 TWh in 2002.

The graph suggests that the theoretical economic cogeneration potential within district heating systems has been estimated at more than 14 TWh for 2010, approx. 15.5 TWh for 2015 and 17 TWh for 2020. This potential arises partly from the fact that it is profitable to replace existing heat production with biomass cogeneration (which is in an economically advantageous position because of green certification, among other things) and partly from the volume growth of the district heating infrastructure.

Providing the prerequisites are in place, the model inclines towards heavy domination of biomass-based cogeneration production. One amongst many reasons for this is the strong instruments which favour renewable electricity production. However, it should be noted that the electricity sector will probably be cautious about relying too heavily on a single type of fuel. This is a lesson industry has learned from the reorganisation of the energy system after the oil crisis. Furthermore, as we observed in the section on the limitations of the model, we have not taken into account any practical logistic limitations concerning the expansion of biofuel-based cogeneration production in the proximity of metropolitan areas, for example.

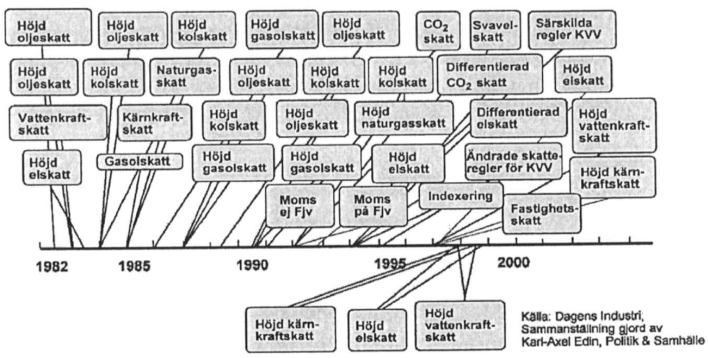
The single most important factor determining cogeneration potential is whether the green certification system is scrapped from 2010 onwards or maintained for a considerable length of time. Cogeneration potential drops from 15.6 TWh, if the green certification system is maintained, to 12.5 TWh, if it is scrapped in 2010. If the certification system remains in place indefinitely, any variations in the other basic assumptions will have a relatively limited impact on cogeneration potential.

However, if the green certification system is scrapped in 2010, cogeneration potential will become considerably more sensitive to variations in the other basic assumptions, such as the concession requirement imposed on integrable systems, the CO_2 tax and the allocation of emission allowances. If the green certification system is scrapped in 2010, cogeneration potential will increase by a little less than 2 TWh, assuming the concession requirement is introduced on integrable systems. If the CO_2 tax on cogeneration is scrapped in addition to the concession requirement and if allocation of emission allowances is grandfathered for new plants, cogeneration potential will increase by a total of 4 TWh.

4.3.2. Economic potential of implemented cogeneration

We have been commissioned by the District Heating Commission to analyse the **economic potential** for cogeneration. As described above, we can exclude the possibility of the volumes stated in this report **overestimating** the **cogeneration potential actually implemented**. It is not part of our mandate to analyse factors behind any past failure to install cogeneration or any future failure to install it to the extent suggested by the economic potential estimated. For this reason, we provide here only an outline of some of the aspects involved.

One basic problem in this context are the uncertainties about the prerequisites linked to investment in power generation. These uncertainties include any changes in taxation, environmental aspects, the regulatory framework etc. which affect the profitability of energy investments. This basically constitutes a source of uncertainty when it comes to investment in cogeneration, either existing or potential. We provide below an illustration of historical changes in the energy market:



From left to right:
Top row: Oil tax increase, Oil tax increase, Coal tax increase, LPN tax increase, Oil tax increase, the CO_2 tax, Sulphur tax, Special rules for CPG plants
Lower top row: Oil tax increase, Coal tax increase, Natural gas tax, Oil tax increase, Coal tax increase, Coal tax increase, Differentiated CO_2 tax, Electricity tax increase
Middle row: Hydroelectric power tax, Nuclear power tax, Coal tax increase, Oil tax increase, Natural gas increase, Differentiated electricity tax, Hydro-electric power tax increase
Upper bottom row: Electricity tax increase, LPG tax, LPG tax increase, Electricity tax increase, Changes in tax rules for CPG plants
Bottom row: District heating's exemption from VAT, VAT imposed on district heating, Indexation, Property tax
The row below the date line: Nuclear power tax increase, Electricity tax increase, Hydro-electric power tax

Graph 36. Historical changes in the determinants of the energy market
Source: Dagens Industri, Chart created by Karl-Axel Edin, The Politics and Society section

The illustration above may be supplemented by the introduction of the green certification system and any uncertainty concerning its long-term outlook.

We provide details below of a number of limiting aspects which we have observed vis-à-vis some implemented and projected cogeneration investments. As a result of the combined impact of these aspects, the cogeneration volume actually implemented has fallen below the theoretically estimated potential:

- Uncertainty about long-term conditions

  Anyone intending to invest in cogeneration may find there is a risk that the conditions might change in the future, along with the historical changes illustrated in the graph above. Since investment in cogeneration requires a financial commitment of at least 20 years, investors may conclude that there is a significant risk of the basis for the original investment calculation changing for the worse during this period and, in the worst-case scenario, of the entire investment coming to nothing.

  An example of this is the gas-fired cogeneration investment in Rya in Gothenburg, where the conditions which prevailed at the time when the investment decision was made (the beginning of 2004) deteriorated later that year.

  Another example is Sydkraft, now E.ON, which is in the process of simultaneously obtaining environmental permits for a gas-based plant and for a biofuel-based plant. E.ON maintains that making a final investment decision at a late stage creates a degree of flexibility, although this depends on the ways in which an operator goes about fulfilling their requirements.

  Major existing and planned cogeneration investments in Sweden are primarily geared towards increasing the production of nuclear and hydroelectric power plants, which often requires reinvestment. The largest power investment currently in progress in the Nordic countries is the building of Finland’s fifth nuclear power plant, investment in which is being driven by both industrial and power companies.

  All in all, companies and owners appear to be exercising caution before investing in cogeneration in Sweden, because of these uncertainties.

- Major investment is linked to company size

  Investing in cogeneration involves major investment expenditure in proportion to the company’s turnover. For example, the investment by Göteborgs Energi in the gas-fired cogeneration plant in Rya corresponds to approx. 70% of the company’s annual turnover, which excludes any commitments this company has undertaken under a long-term gas supply agreement.

  We have also noted that the investment expenditure of some other municipal companies which are examining or considering investment in cogeneration adds up to between 35 and 160% of their annual turnovers. Investment on such a major scale carries significant risks for both power companies and municipality owners (guarantees, finance etc.). One alternative to this is that the company could, instead, choose to invest in heat production alone, which carries a considerably smaller price tag and sidesteps any risks connected with the conditions of electricity production.

  Examinations carried out by PricewaterhouseCoopers in the latter part of 2003 indicated that many municipalities were reluctant to see their own power companies become exposed to risk. This has restricted the scope of both electricity trading and investment in electricity production.

- Access to, and requirements for, primary fuels

  An important factor to be considered before any investment decision can be made is the future requirements for primary fuels, both as regards access thereto and their cost and competitive power. In the present report, biofuels and natural gas are of particular interest.

  The stated ambition of Sweden's energy system is the increased use of biofuels in both heat and electricity production. This orientation is justified if viewed against this report's calculation results, which suggest that biofuels constitute a significant part of cogeneration potential. However, our calculations are based on very simplified assumptions which project a uniform biofuel price in Sweden and no changes in biofuel prices in real terms, despite the fact that demand will increase significantly with the expansion of biomass cogeneration.

  Nonetheless, anyone intending to invest in biomass cogeneration must form his own opinion about what the future purchase cost will be of supplying biofuels to the location where the plant will be installed. We have also noted a range of diverse opinions about the long-term development of the biofuel price and concerns that any considerable increase in reliance on biofuels might result in an increase in the price of biofuels.

  The situation is even more complex as regards access to, and requirements for, natural gas.

  According to estimates made by Svensk Naturgas AB and others, large quantities of natural gas could be made available primarily to district heating systems and large-scale industry in the eastern and central part of Svealand. Cogeneration constitutes the overwhelming bulk of this gas potential. Similar estimates of potential new delivery destinations have also been produced by Nova Naturgas and Sydkraft Gas. Examples of potential markets include the areas around Örebro, Linköping, Mälardalen, the Stockholm region, Gävle and parts of Bergslagen. Some reports suggest that letters of intent and preliminary agreements have been signed in many of these areas for a natural gas capacity of 10-15 TWh.

  However, the economic conditions for gas-based cogeneration are not clearly competitive, as is also suggested by the analyses carried out as part of this report. This generates uncertainty as to the profitability of routing gas pipelines to new supply areas. For example, Svensk Naturgas previously planned the routing of a gas pipeline to Svealand for 2008 or around that time, but reports we received in February 2005 suggest that this time-table has been pushed back to around 2010-2012, in order that a large-scale gas supply system, which would be competitive for cogeneration, can be put in place.

  The aggregate impact of these aspects relating to biofuels could affect any decision to invest in cogeneration, in terms of time, scale or choice of alternative.

- Changes in electricity prices

  The price of electricity in the Nordic market sank to a new low in the years immediately following the reform of Sweden's power market in 1996. In the period following 1996, both power companies and industrial enterprises put their power production capacity out of operation. The capacity put out of operation concerned any production which entailed variable costs which were high in comparison to the low price levels of fossil fuel-fired condensing power generation, for example. However, because of the capacity shortage in the winter of 2002 and 2003, some production was "de-mothballed", so to speak.

In addition to the uncertain conditions described above, we note that electricity price variations have different impacts on plants with low variable costs (hydro-electric and nuclear power plants) and those with high variable costs (cogeneration and condensing power generation plants). Any decrease in electricity prices will hit the latter plants twice as hard, because of the reduced cash flow once the plant has been put into operation and because of the reduced operating hours (the plant only being operated when its variable cost is lower than the price of electricity). Should there be any additional uncertainty about future prerequisites for cogeneration, a player might conclude that investing in other projects would make more sense.

- The time aspect

  The process from the initial investment decision to the construction and deployment of a cogeneration plant takes several years, because of factors such as environmental assessment, preparations, purchasing and construction. It is therefore possible that any estimated potential might materialise later than expected because of such delays. Moreover, any extension of the preparation process risks entailing changes to previously made decisions and suspending investment, as a result of which the cogeneration plant might never become a reality.

- Other aspects

  Some market players have sought to explain this by suggesting that the major power companies in Sweden (primarily Vattenfall, Fortum and E.ON) do not want the Nordic electricity system to expand its electricity supply. An isolated cogeneration plant might prove a profitable investment in itself, but if the additional electricity supply which it brings to the market triggers a reduction in electricity prices, then that cogeneration investment could have a negative impact on the profitability of the energy company's other power generation portfolios, as some players see it.

  It should be noted that the major power companies (Vattenfall, Fortum and Sydkraft/E.ON) account for 40% of the estimated economic cogeneration potential, while the remaining 60% is distributed among energy companies in municipal ownership.

  Furthermore, it is possible that the investor may conclude that an investment which initially appeared to be profitable is in fact unprofitable, because of environmentalist or public opinion pressure. For example, Vattenfall decided to shelve an investment in residual fuel oil-based power generation in Stenungsund after the project met with fierce protest.

We can therefore conclude, on the basis of the outline discussion above, that, for a number of reasons, any investment in cogeneration actually implemented will fall short of the economic potential theoretically estimated by the present report.

4.3.3. Comparison with other studies

In the following section, we compare the results of a selection of recent assessments of the cogeneration potential of Sweden's district heating industry.

In February 2004, the Swedish District Heating Association published a report entitled "The Future of District Heating and Cogeneration". This report forecast that cogeneration capacity would grow to 11 TWh by 2010. Its theoretical calculation projected the 2010 technical cogeneration potential at 27 TWh.

As part of the Nordleden study (District Heating, Cogeneration and Waste Incineration in Sweden, June 2002), estimates were made of the technical potential for electricity production within the district heating sector. In estimating the potential, the study examined whether biofuels should take priority over natural gas in the merit order and vice versa. The potentials estimated stand at 17-18 TWh and 27 TWh respectively.

Consequently, the estimates of potential of the Nordleden study differ from the estimates in this report. It should be noted, however, that our task does not include any detailed analysis of the differences between the study and our report.

An overview of Sweden's potential for cogeneration, as per various assessments	**TWh electricity per year**
Economic cogeneration potential for 2010-2020, as per this report	14-17
Swedish District Heating Association's forecast for 2010 (survey)	11
SDHA's calculation of the technical potential for 2010	27
SDHA's calculation of the technical potential for 2010 (including Mälardalen having access to natural gas)	41
Nordleden, calculation of technical potential (preferably biofuels)	17-18
Nordleden, calculation of technical potential (preferably natural gas)	27

4.3.4 Third-party access (TPA)

Although third-party access (TPA) to the district heating systems has been considered by the District Heating Commission, we had no mandate as part of our task to analyse this issue in any great detail. TPA is a complex issue and one which requires a number of questions to be addressed before the impact of TPA on the district heating market and cogeneration potential can be assessed. We provide examples of such considerations below.

It is difficult to transfer experience of deregulation in other markets to the district heating market, because it consists of 200 local submarkets.

In general, the district heating market is dominated by major barriers to entry, in the form of high initial investment requirements. Therefore, the players who are most likely to be interested in TPA are primarily waste heat suppliers.

Before we can forecast the likely impact of TPA on cogeneration potential, we first need to answer a few questions:

- What rules should apply to TPA? How should responsibilities be divided between the producer, the network owner and, where applicable, the supplier?

- What share of the district heating market is relevant? What kind of role could waste heat play and what kind of possibilities are there for the expansion of waste heat, in terms of being used within district heating networks? Which industrial investments in cogeneration could be self-sufficient and which would require income from the sale of waste heat? How would such investments affect investment in cogeneration by district heating companies?

- What kind of possibilities would a heat supplier have to make competitive offers to consumers? How should processing industries' service and maintenance periods be dealt with?

- What possibilities for cross-subsidisation are likely to arise for existing district heating companies which are exposed to competition and for those that are not? How might any such possibilities affect competition from independent heat suppliers?

- To what extent are waste heat suppliers interested in selling heat to end-users, given that their core activities do not currently include the selling of district heat? Currently, several municipalities purchase waste heat from adjacent industries at what are usually favourable prices. Waste heat suppliers and district heating companies could use the possibility of supplying heat to end-users as an argument to push up the price of waste heat. Eventually, this may therefore result in a higher heat price tag for the consumer.

5. The potential for small-scale cogeneration

There are three market segments for power demand which is lower than the minimum cogeneration plant size of 8/20 MW_{el} examined in Chapter 4.

- Medium-scale cogeneration: 1-8/20 MW_{el}
- Small-scale cogeneration: 50-1,000 kW_{el}
- Micro-cogeneration: 0-50 kW_{el}

International practice tells us that both small-scale cogeneration and micro-cogeneration exist. Their market penetration rates are high in the Netherlands, the United Kingdom and Germany. Where power demand is low, gas engines are used and, where power demand is high, gas turbines are used. The most commonly used fuel is natural gas. If biofuel is used as a resource, however, access to commercial technology is considerably more limited. There are, admittedly, some small-scale cogeneration development projects which use biofuel, but it is likely to be some time before commercial applications become available.

The cost of small-scale cogeneration technology continues to be very high. In Europe, approximately EUR 3 000-4 000 is paid per kW_{el} for small-scale plants.

In Sweden, there is as yet no natural gas-based small-scale cogeneration or micro-cogeneration. However, the potential exists in regions which have access to natural gas. Biogas-fired plants exist, to a limited extent.

As part of this task, we have postulated that heating infrastructure is theoretically available for natural gas-based medium and small-scale cogeneration and micro-cogeneration. In order to estimate the volume of the heating infrastructure for medium and small-scale cogeneration and micro-cogeneration, we have assumed that it consists of all the infrastructure which remains after cogeneration within district heating (demand greater than 20 and 8 MW_{el}, respectively) has used up its potential. Availability of natural gas was a basic prerequisite in estimating the heating infrastructure for medium and small-scale cogeneration and micro-cogeneration.

5.1 Methodology

In estimating cogeneration potential, we first estimated the potential heating infrastructure outside the district heating system. Our source of information here was the model which was produced for calculating the potential for cogeneration within district heating systems.

- Firstly, we selected urban areas with access to natural gas. Both urban areas which currently have access to natural gas and those which would have access to natural gas if a natural gas pipeline were routed to the Mälar region and Gävle were included in the potential. The heating infrastructure outside urban areas was not included in the potential, as it is assumed that this infrastructure will not be connected to a natural gas distribution network.

- Secondly, we selected heating infrastructure which comes under the following two groups:
    - Heating infrastructure in urban areas which have no access to district heating

- Heating infrastructure in urban areas where either cogeneration within district heating has not been profitable or there has not been sufficient heating infrastructure for cogeneration investment.

5.2 Calculated potential

The potential heating infrastructure for medium and small-scale cogeneration is shown in the table below. This potential infrastructure is substantially larger than the volume of existing natural gas deliveries to the heating market outside district heating systems. In 2003, their capacity amounted to 1.8 TWh.

Potential heating infrastructure for medium and small-scale cogeneration			
TWh (heat)	2010	2015	2020
Within existing natural gas network	6.6	6.1	5.4
Within future natural gas network	10.6	9.7	8.5
Sweden as a whole	37.1	35.3	33.2

The heating infrastructure decreases between 2010 and 2020 because we have assumed that a greater number of urban areas will reach the lower limit for large-scale cogeneration, i.e. 8 MW_{el} in respect of biomass and 20 MW_{el} for natural gas.

The potential heating infrastructure has been adjusted downwards because we have assumed that it would only be possible for natural gas to become physically available to 50% of the market. In addition, we have assumed that 50% of buyers with access to natural gas would be interested in small-scale cogeneration. In such a scenario, only the following adjusted potential heating infrastructure remains:

Adjusted heating infrastructure for medium and small-scale cogeneration			
TWh (heat)	2010	2015	2020
Within the existing natural gas network	1.6	1.5	5.4
Within the future natural gas network	2.7	2.4	2.1

We then applied an assumed electricity output appropriate for small-scale cogeneration plants to the adjusted heating infrastructure for medium and small-scale cogeneration. The assumed output approximated to 0.4, the resulting potential electricity production being as follows:

Potential electricity production			
TWh (heat)	2010	2015	2020
Within the existing natural gas network	0.7	0.6	0.5
Within the future natural gas network	1.1	1.0	0.8

Our calculations show that potential electricity production for medium and small-scale cogeneration amounts to between 0.5 and over 1 TWh_{el}. Even if all buyers with access to natural gas were interested in cogeneration, the potential would be less than 2 TWh_{el}.

5.3 Barriers to consumer-owned micro-cogeneration based on fossil fuels

The applicable Energy Taxation Act exempts any electricity produced by plants smaller than 100 kW from electricity tax if the producer does not supply electrical power in a professional capacity (Swedish Tax Agency 2004 and SFS 1994:1776). This means that tax credits are not granted for any fuel used in production. Instead, any electricity produced by such means is exempt from electricity tax.

If electricity is produced in a micro-cogeneration plant by the consumer (who does not supply electric power), the fuel used is subject to full taxation and the energy tax and the CO_2 tax must be paid. However, the consumer is not required to pay electricity tax. If using natural gas, the consumer must pay an energy and CO_2 tax of around SEK 0.26/kW for both electricity and heat.

If electricity is instead produced in a micro-cogeneration plant by an energy company (which supplies electric power), standard deduction rules apply and credits are granted for fuels used in electricity and heat production. In return, the consumer is required to pay an electricity tax of SEK 24.1/kWh for any power used (the tax rate being slightly lower in northern Sweden). Heat production is subject to a CO_2 tax rate of over SEK 0.05/kWh. Therefore, under current energy taxation rules, operating a micro-cogeneration plant will be cheaper if it is owned by an energy company.

However, according to current practice, a consumer becomes a supplier when he concludes an agreement on electricity supply. This means that, in practice, all owners of micro-cogeneration plants are subject to the taxation which applies to energy companies.

6. Cogeneration potential in industry

In 2003, cogeneration potential in industry amounted to 5.2 TWh[11], of which 5.1 TWh was produced by the paper and pulp industry. The remaining part was generated by the chemical and petrochemical industry.

We have not been able to carry out an analysis of cogeneration potential in industry to the level of detail that we applied to the district heating systems, i.e. on the basis of data concerning specific plants, for example. However, in line with our task, we have been able to produce a rough estimate of cogeneration potential in industry by means of international comparison.

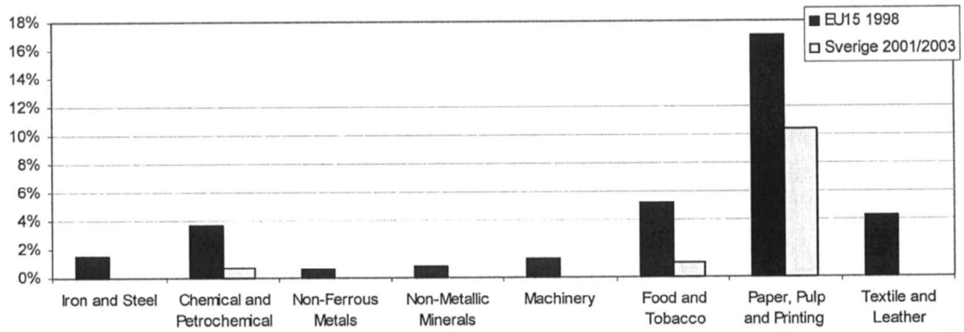
All our comparisons are based on industrial fuel consumption (which does not however include industrial electricity consumption). The estimated potential does not include any part of the heating infrastructure estimated for cogeneration potential within district heating systems. For this reason, there is no overlap between the potential within industry and the potential within district heating systems.

[11] Statistics Sweden's Annual Energy Statistics (electricity, gas and district heating), 2003.

6.1.1. International comparison

A comparison between Sweden and the EU-15 shows that industry in Sweden produced little of its own electricity in proportion to its fuel consumption. In the following section, electricity produced from industrial cogeneration is presented as the proportion of fuel used by various industries. The data used are the 1998 data for the EU-15 and the 2001 data for Sweden.

Electricity produced from industrial cogeneration,
as a proportion of the fuel used by the EU-15 and Sweden



Graph 37. Electricity produced from industrial cogeneration, as a proportion of the fuel used by the EU-15 in 1998 and Sweden in 2001.
Sources: Eurostat, Combined heat and power production in the EU 1994-1998 and IEA, Energy balance of OECD countries 1960-2001, Paris 2003.

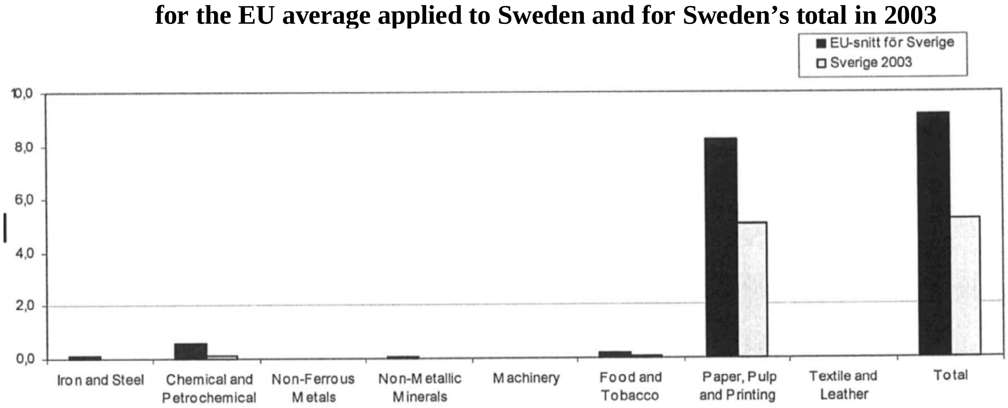
The graph above suggests that Sweden relies on cogeneration, as a proportion of its total fuel supply, considerably less than the EU-15.

The most energy-intensive industries in Sweden, i.e. the paper and pulp industry and the chemical and petrochemical industry, have considerably less cogeneration production than the equivalent industries in other countries.

<u>Sweden's cogeneration potential, based on a comparison with the EU</u>

In 2003, the cogeneration potential of Swedish industry stood at 5.2 TWh. If Sweden's cogeneration production were equivalent to that of the EU average, its cogeneration production could have totalled over 9 TWh. The graph suggests that most of this potential exists in the paper and pulp industry. The remainder exists in the chemical and petrochemical industry.

Sweden's electricity production and industrial cogeneration,
for the EU average applied to Sweden and for Sweden's total in 2003

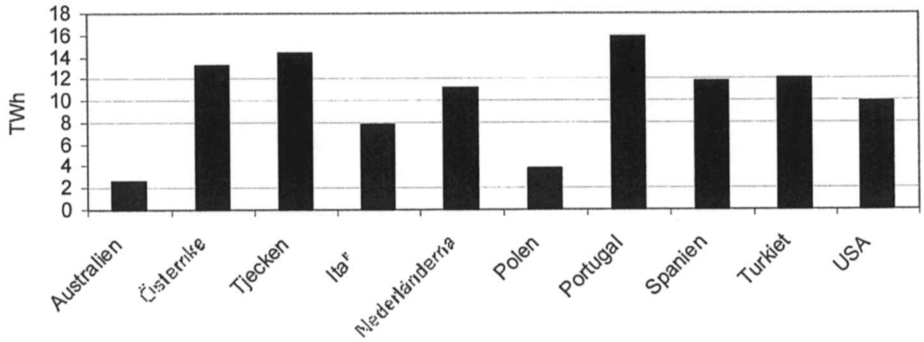


Graph 38. Sweden's electricity production and industrial cogeneration for the 1998 EU average and the 2003 total.
Source: Eurostat, Combined heat and power production in the EU 1994-1998 and IEA, Energy Balance of OECD countries 1960-2001. Paris, 2003.

<u>The cogeneration potential of the Swedish paper and pulp industry, based on a comparison with OECD countries</u>

Potential electricity production from industrial cogeneration for Sweden's paper and pulp industry, as compared to other countries' cogeneration-fuel supply ratio, is shown below. This graph shows that there is major potential for increasing Sweden's electricity production within its paper and pulp industry from the current level of over 5 TWh to around 10-15 TWh.

The cogeneration-fuel use ratio of various OECD countries, as applied to Sweden's paper and pulp industry's fuel use



From left to right: Australia, Austria, Czech Republic, Italy, Netherlands, Poland, Portugal, Spain, Turkey and USA

Graph 39. The cogeneration-fuel use ration of various OECD countries' paper and pulp industries, as applied to Sweden's paper and pulp industry's fuel use (Cogeneration-fuel supply ratio data for 1998; Sweden's fuel consumption for 2001).
Source: IEA Electricity Information 2000.

6.1.2. Comparison with completed studies

In the following section we compare the results of a selection of recent assessments of the cogeneration potential of Swedish industry.

In November 2004, the Swedish Bioenergy Association (SVEBIO) published a survey which had been conducted in order to gauge opinion on the impact of the green certification system on biofuel-based electricity production. The survey targeted the forest industry. 31 of the 33 biomass cogeneration plants in the forest industry which were entitled to green certification responded to SVEBIO's survey. The conclusion of the survey was that forest industry players expected a 60% increase in biomass cogeneration production (from just over 4 TWh in 2003 to 6.3 TWh in 2010). Another important remark made by the forestry industry is that they would prefer the green certification system to continue for a longer period, i.e. beyond 2010. This would provide longer-term infrastructure on the basis of which decisions to invest could be made.

Some of those who responded to SVEBIO's survey expressed an initial interest in black liquor gasification, a technology which enables higher electricity outputs in the paper and pulp industry. However, the companies interviewed stated that it would take at least 10 years before this technology was mature enough for commercial exploitation.

In its publication *A Review of the Green Certification System, Stage 2*, the Swedish Energy Agency forecast a “reasonable” potential of 7 TWh by 2015. The same document projected the technical potential at 11-12.7 TWh (Möllersten, 2003).

In the following table, we provide an overview of Sweden’s cogeneration potential, as assessed by different sources. The reference value is the 2003 output.

An overview of the Swedish industry’s cogeneration potential, as per different assessments	**TWh electricity per year**
2003 output	5.2
EU-15 average in 1998, as applied to Sweden	9.1
The 1998 average for various leading OECD countries (paper and pulp industry only)	10-15
SVEBIO survey, 2010 survey (forest industry, biomass cogeneration only)	6.3
The Swedish Energy Authority’s “reasonable” potential for 2015 (*A Review of the Green Certification System*, Annex 6)	7
Möllersten 2003 (technical potential of industrial backpressure)	11-12.7

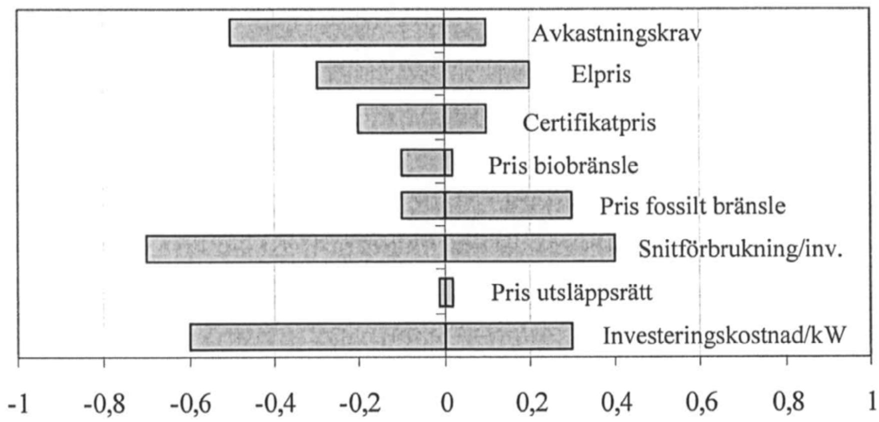
Discussions with industry players have revealed a great deal of interest in the expansion of industrial cogeneration. Typically, this is explained by the argument that investment at current electricity prices is profitable in itself and the argument that an increased supply of electricity in the Nordic electricity market would boost the chances of preventing a long-term increase in electricity prices.

Appendix 1 – A sensitivity analysis of the potential for cogeneration within district heating

In this appendix, we present the result of a number of sensitivity analyses which were carried out in order to assess the potential for cogeneration within district heating (as dealt with in Chapter 4 of the report). In the sensitivity analysis, we have analysed the results' sensitivity to the varying of variable parameters.

The sensitivity analysis has been carried out in respect of the 2015 reference scenario. The result is illustrated in the graph below and a brief comment is provided below.

Sensitivity analysis of the cogeneration potential in the reference scenario, TWh



From top to bottom:
Required return; Electricity price; Certificate price; Biofuel price; Fossil fuel price; Average consumption per inhabitant; Emission allowance price; Investment cost/kW

Graph. A sensitivity analysis of the cogeneration potential in the 2015 reference scenario

We can conclude on the basis of this sensitivity analysis that the cogeneration potential calculated in the model is not sensitive to single isolated variations in the variable parameters. Note, however, the major impact on cogeneration potential in situations where several variable parameters assume both favourable and unfavourable values simultaneously. This is illustrated by the S curves explained in a foregoing section of this report.

We provide comments below on the effects of each individual variation in the variable parameters.

Required return

Required return varies between 7.5 and 10.3% (corresponding to a risk-free real interest reduction of -0.65% or increase of +1.7%, compared to the reference scenario). Required return has a limited effect only on the potential for new cogeneration. This may be explained by the fact that there are only a handful of plants within the threshold of profitability. Where the power demand of a system exceeds the minimum size, investment is profitable in the majority of cases.

Electricity price

The electricity price varies between SEK 200 and 300/MWh. Of course, electricity price has an impact on the profitability of new cogeneration construction. However, most biomass investments remain at the same level and never fall to the level of the electricity price of SEK 200/MWh, because a significant part of their income comes from green certification.

Certificate price

The certificate price varies between SEK 150 and 250/MWh. It is only natural that certificate price should have an impact on the profitability of new cogeneration construction. However, the variations within the interval do not determine the potential. If, on the other hand, the green certification system is scrapped, major variations in the potential occur, as described above.

Biofuel price

The biofuel price varies between SEK 135 and 165/MWh. The price of biofuel has only a marginal impact on the potential for new cogeneration, which leads us to conclude that, under the given prerequisites and assumptions, investment in biomass cogeneration will be made in the majority of cases, provided that the heating infrastructure is adequate.

Variations in the price of biofuel do not have any major impact on the potential for the combined cycle technology.

Fossil fuel price

The price of fossil fuels (coal, natural gas and oil) varies between low and high values. The price of fossil fuels affects the potential for new cogeneration to a certain extent.

From this we may conclude that, under the given prerequisites and assumptions, investment in biomass cogeneration will be made in the majority of cases, provided that the heating infrastructure is adequate. In itself, the price of fossil fuels is not a determining factor.

Heat consumption per inhabitant

The average heat consumption per urban inhabitant varies between 8.5 and 9.5 MWh per inhabitant and year.

The potential is sensitive to variation in this assumption.

Investment cost per kW

The investment cost per kW varies between low and high values, both for CCGT and for biomass cogeneration.

The potential is sensitive to variation in this assumption.