THESIS ON MECHANICAL AND INSTRUMENTAL ENGINEERING E58

Model for the Analysis of Combined Heat and Power Production

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Declaration:
Hereby I declare that this doctoral thesis, my original investigation and achievement submitted for the doctoral degree at Tallinn University of Technology has not been submitted for any academic degree.

/Eduard Latõšov/

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Soojuse ja elektri koostootmise analüüsi mudel

EDUARD LATÕSOV

TTÜ KIRJASTUS

CONTENTS

INTRODUCTION

Energy policy in the present-day world is based on two main directions: energy efficiency and environmental protection.

The Electricity Market Act, Long-term Public Fuel and Energy Sector Development Plan until 2015 and Estonian Electricity Sector Development Plan until 2020 are the main standard acts for the Estonian energy sector. The above-mentioned documents are based on the European Union directives and draw attention to the necessity for promoting efficient CHP production.

CHP production is an available, efficient, clean, and reliable approach to generating power and thermal energy from a single fuel source. By installing a CHP system designed to meet the thermal and/or electrical loads of a facility/district heating area, CHP can greatly increase the efficiency and decrease energy production costs. At the same time, CHP reduces the emission of greenhouse gases, which contribute to the global climate change (i.e. efficient CHP production is one of the effective energy consumption methods where the CHP production from renewable fuels is preferable).

At the moment Estonian economy is highly dependent on fossil fuels. Approximately 90% of Estonia's energy is produced through the combustion of fossil fuels. The remaining 10% comes from renewables, such as biomass, hydropower and wind. The main domestic energy source is the combustion of oil shale, which puts high pressure on the environment, i.e., approximately 70% of atmospheric pollution, 80% of effluents and 80% of generated solid waste come from the oil shale power industry. [1]

Regarding the agreements within the bounds of Directive 2001/77/EC and Long-term Public Fuel and Energy Sector Development Plan until 2015, Estonia should increase the share of electricity produced from renewable fuels and in the CHP plants of gross electricity consumption.

Relying on the aforesaid obligations, the strategic objectives for the Estonian electricity sector have to ensure that

- by 2010 the renewable electricity makes 5.1% of the gross electricity consumption and at least 8% by 2015;
- by 2020 the electricity produced in combined heat and power plants forms 20% of the gross consumption and at least 18% (at the moment ~15% is produced in the CHP mode) by the year 2015.

To achieve the targets, the government should take measures to make the energy production from renewable fuels and CHP production more attractive. But at the same time an investor should take steps to make an investment decision, not the government.

It is important that the state policy for supporting investments in the renewable energy and CHP generation is able to secure investments against all kind of risks and provide clear and stable rules for the investment planning. For these purposes we need some common rules and methods to evaluate the investments in the energy sector which are accepted by state institutions, the banking system and investors as well as a set of the approved and methodically updated initial technical data for the appropriate calculations and estimations. The environment which has influence on the investments in the renewable energy and CHP production faces a lot of issues. It is important to discuss the problems and try to solve them:

- The energy related legislation is not stable. Too frequent changes in values and conditions for gaining feed-in tariffs influence the economic activity of energy companies. It does not support investments, although the main target of energy-related legislation is designed to meet opposite goals;
- The estimation methods of factors and values as well as their interpretation differ. As an example, they include the rules and requirements for energy business plans and projects subsidy application from governmental institutions, methods for evaluating the maximum heat sale price, methods for calculating the feed-in tariffs, etc;
- The initial technical and economic data used for the calculation of CHP plant related issues varies. As an example, no accepted forecast for fuel prices, electricity prices is available. No collecting, systematizing and updating methods have been approved.

To solve the above mentioned problems, the work must be aimed at the collection and systematization of technical and economic data as well as at the methods required for planning CHP plants. It is important to make this knowledge available and obligatory for the application to all parties who are directly or indirectly related to the expansion of energy production.

Based on the aforesaid assumption, the goals of this study are:

- Taking into consideration the main problems and tasks of CHP plant planning based on the general-to-particular approach;
- Development of a mathematical model based on basic and simplified conceptual models for solving the issues related to planning the construction of a CHP plant under the conditions in Estonia. Examination of mathematical interactions between the components in a mathematical model. Providing the analysis of technical and economic values for their use as initial data for the calculations;
- Requirements determination for developing a computational program based on the mathematical model, discussion about the issues related to the program development.

The author hopes that the description of approaches and principles regarding the analysis of technical and economic consequences of renewable energy implementation based CHP systems will be somehow noticed by the parties influencing the CHP expansion. The implementation and further development of methods and principles will help to establish regular communication between the parties, make their work more efficient, provide investors with clear, stable and common decision making rules, and based on this, to increase the number of decisions in order to invest in environmentally friendly and efficient methods of energy production.

This study is structured as follows. Chapter 1 provides an overview regarding creation of the basic conceptual model and its components. An overview regarding the main objects and factors in a CHP plant activities that affect the plant's viability is given and their interrelations discussed. Chapter 2 describes the development of a simplified conceptual model. The point in creating a simplified conceptual model is to filter out the data, which is not valid or non-typical for Estonian conditions and adjust the remaining results for simplifying the analysis. Chapter 3 deals with the creation of a mathematical model for the analysis of technical and economic impact of renewable energy based CHP systems. Chapters 4 describes the composition of a computer program based on the mathematical model and illustrates the application of principles discussed in the earlier chapters in practical calculations.

Method of research

The main goal of the study is to create a mathematical model for planning the construction of a CHP plant. The model should provide information about the measurement of investments based on Estonian conditions. In order to compose the mathematical model, the general-to-particular approach is used.

Development of the conceptual model is the most important part of modelling process. The conceptual model is the foundation of the quantitative, mathematical presentation of the object/process (mathematical model), which in turn is the basis for the computer code used for simulation.

The context in which a conceptual model is developed constrains the range of its applicability. A conceptual model is by necessity a simplification of the real system, but the degree of simplification must be commensurate with the problem being addressed. [2]

In general terms, a conceptual model is a qualitative tool being expressed by ideas, words and figures. A mathematical model is a qualitative tool expressed in the form of mathematical equations. The two are closely related. In essence, a mathematical model results from translating the conceptual model into a well-posed mathematical problem that can be solved. [2]

To provide a precision way of model development the following steps shown in *Figure 1* are used in this study.

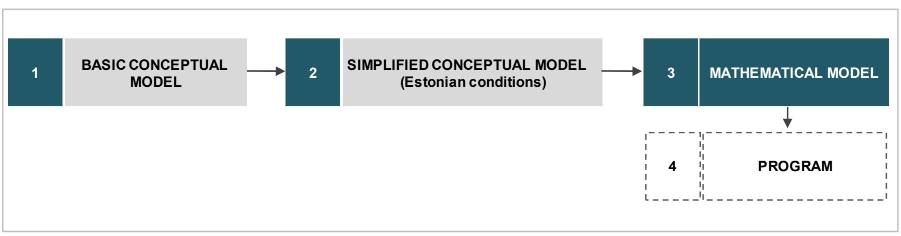

Figure 1 Mathematical model development stages

The main goal of the first step of model development (basic conceptual model) is to give an overall overview of the main objects and factors in CHP plant operating activities, including their interrelations that affect the plant's viability.

The goal for a simplified conceptual model is to filter the data which is not valid or non-typical for Estonian conditions and adjust the remaining results for simplifying the analysis.

The mathematical model is composed based on the simplified conceptual model. The mathematical model should be used in the initial stage of CHP plant planning, because the main decisions on the further development of CHP plant are mainly made in the pre-feasibility stage.

Regarding [3], the pre-feasibility study is a preliminary assessment of technical and economic viability of the proposed project. Alternative approaches to various elements of the project are compared, and the most suitable alternative for each element is recommended for further analysis. The cost of development and operations is estimated. The anticipated benefits are assessed so that some preliminary economic criteria for the evaluation can be calculated.

The implementation of mathematical model should provide an understanding of the CHP plant related business development issues.

The personal contribution of the author

The contribution of the author to the PhD thesis and papers include the following:

- The author is responsible for the PhD thesis (i.e. literature overview, data collection, analysis and calculation, model preparation, program composition).
- Eduard Latõšov is the corresponding author of the papers I, II, IV, V, VII, VIII and IX (see chapter List of publications). He is responsible for the data collection, analysis, calculation and presentation of the results.
- Eduard Latõšov is a co-author of the papers III and VI (see chapter List of publications). He is responsible for the Estonia related initial data collection and internal revision of papers.
- Preparing the PhD thesis and papers is based on the experience obtained during the participation in the CHP plant related pre-feasibility and feasibility studies for different locations in Estonia (e.g. Tallinn, Tartu, Pärnu, Jõgeva) as well as in other energy related projects (see Consulting Assignments in Appendix 2).
- The author has calculated/evaluated the impact of subsidy mechanisms on the biomass based electricity prices, estimated the competitiveness of combined heat and power plant technologies in Estonian conditions, calculated different CHP expansion scenarios (different technologies, fuels and available subsidies) in a 30000 MWh district heating area and provided some case-specific consultant arrangements for the

implementation of combined heat and power production with the mathematical model composed for CHP planning.

Scientific novelty of the thesis

The novelty of the work includes developing a new method allowing estimation of the economic and technical viability of CHP systems in Estonian conditions. The model development started from point zero. It is not an update or a duplicate of any of the existing programs.

The composition of the mathematical model is based on the general-to-particular method of approach. It allows working out the mathematical models for other conditions (additional modelling tasks, models for the other countries, etc.).

The main features of the used approaches and created models are:

- A web-based application concept. The web-based application gives an opportunity to access the calculations from anywhere and at anytime by using a computer connected to the web, web browser and the right user login data. The web-based application will also help to save some disk space. The web-based application will allow updating the process in the easiest way where all changes and new features are delivered to the program users automatically;
- The transparency of computation steps and initial data. The user has a possibility to examine all computation steps and logics used in the modelling. This approach avoids the software treating as if it was a "black box" without any knowledge of internal implementation. It will potentially increase the knowledge and trust of the users, as well as allow debugging and development of the model in a most efficient way (cooperation with user);
- Considering the computational transparency as well as free for use principles, the target group of the model/program applies to all parties involved in CHP planning and development activities, i.e. heat and power engineers, enterprises with high heat demand, businessman, local government, consultants, etc.

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I owe big gratitude to the anonymous reviewers of my papers who sent their feedback with interesting suggestions about the ideas and approaches to the problems that have been discussed.

I would like to thank my family and friends for the patience and support.

Eduard Latõšov

ABBREVIATIONS AND SYMBOLS

Abbreviations
CHL – constant heat load
CHP – combined heat and power
DH – district heating
EIA – environmental impact assessment
FCFE – free cash flow on equity
FCFF – free cash flow of firm
HRSG – heat recovery steam generator
IRR – internal rate of return
NPV – net present value
O&M – operation and maintenance
ORC – Organic Rankine Cycle
RES – renewable energy sources
TDHL – temperature-depended heat load
UDHL – user defined heat load
WACC – weighted average cost of capital

Symbols
$Corr^{ASHPRICE}$ – ash disposal price correction factor
$Corr^{CO2RATE}_t$ – carbon dioxide emission charge rate correction factor
Cor^{CORATE}_t – carbon oxide emission charge rate correction factor
$Corr^{ELPRICE}_t$ – electricity price correction factor
$Corr^{FIXEDOM}_t$ – fixed O&M costs correction factor
$Corr^{FUELPRICE}_t$ – fuel price annual correction factor
$Corr^{heat.demand}_t$ – heat demand annual correction factor
$Corr^{HEATPRICE}_t$ – electricity price correction factor
Cor^{HMRATE}_t – heavy metals emission charge rate correction factor
$Cor^{NOxRATE}_t$ – nitrogen dioxides emission charge rate correction factor
$Cor^{PARTRATE}_t$ – particulates emission charge rate correction factor
$Corr^{QUOTAPRICE}_t$ – CO_2 quota price correction factor
$Cor^{SO2RATE}_t$ – sulphur dioxide emission charge rate correction factor
$Cor^{VOCRATE}_t$ – volatile organic compounds emission charge rate correction factor
$Corr^{VOM}_t$ – variable O&M costs correction factor
$COSTSash_t$ – annual ash disposal costs
$COSTSco_t$ – annual costs on carbon oxide emission
$COSTSco2_t$ – annual costs on carbon dioxide emission
$COSTSenv_t$ – annual environmental costs
$COSTSfixedom_t$ – t year annual fixed O&M costs
$COSTSfuel_t$ – annual fuel costs
$COSTShm_t$ – annual costs on heavy metals emission
$COSTSinv$ – project investment costs
$COSTSnox_t$ – annual costs on nitrogen dioxides emission

$COSTSpart_t$ – annual costs on particulates emission
$COSTSquota_t$ – annual carbon dioxide quota costs
$COSTSso2_t$ – annual costs on sulphur dioxide emission
$COSTSvoc_t$ – annual costs on volatile organic compounds emission
$COSTSvom_t$ – *i* year annual variable O&M costs
DEBT – sum of debt
$DEBTin_t$ – interest annual repayment
$DEBTloanpart_t$ – loan part annual repayment
DEBTrate – interest rate
DEBTrep – repayment period
DH – reference year degree-hours
DISPash – the share of ash to be disposed by the ash disposal system
DISPwet – the increase of ash weight in comparison to dry ash disposed weight
eexIRR – expected equity related IRR
elEFFm – electrical efficiency at minimum load
elEFFmed – electrical efficiency at intermediate load
elEFFnom – electrical efficiency at nominal load
elPm – minimum electrical capacity
elPmed – electrical capacity at intermediate point
elPnom – nominal electrical capacity
eNPV – equity related NPV
EQUITY – equity capital
FUELash – ash content
FUELcal – fuel calorific value
FUELco2 – carbon dioxide emission factor
FUELco – carbon monoxide emission factor
FUELfossil – fossil fuel
FUELgaseous – gaseous fuel
FUELhm – heavy metals emission factor
FUELliquid – liquid fuel
FUELnox – nitrogen oxides emission factor
FUELpart – particulates emission factor
fuelPm – minimum fuel capacity
fuelPmed – electrical fuel at intermediate point
fuelPnom – nominal fuel capacity
FUELren – renewable fuel
FUELso2 – sulphur dioxide emission factor
FUELsolid – solid fuel
$FUEL_{VOC}$ – volatile organic compounds emission factor
HCI_n – *n* consumer temperature-depended heat consumption indicator
heatEFFm – heat efficiency at minimum load
heatEFFmed – heat efficiency at intermediate load
heatEFFnom – heat efficiency at nominal load
HEATloss – heat loss in district heating network
heatPm – minimum heat capacity

heatPmed – electrical heat at intermediate point
heatPnom – nominal heat capacity
LOADm – minimum capacity point
LOADmed – intermediate capacity point
OMfixed – base year fixed O&M costs
OMv – base year variable O&M costs
PAYMENTan – annual annuity repayment
PRICEash – ash disposal rate
PRICEel – electricity price
PRICEfuel – fuel price
PRICEheat – heat price
PRICEquota – CO_2 quota price
P^{const}_m – CHL *m* consumer heat load for reference year
pexIRR – expected project related IRR
pNPV – project related NPV
$P^{user}_{i,l}$ – reference year *i* hours TDHL *l* user heat load
Q^{const}_m – CHL *m* consumer annual heat demand
Q^{temp}_n – TDHL *n* consumer annual heat demand
RATEco – carbon oxide emission charge rate
RATEco2 – carbon dioxide emission charge rate
RATEhm – heavy metals emission charge rate
RATEnox – nitrogen dioxides emission charge rate
RATEpart – particulates emission charge rate
RATEso2 – sulphur dioxide emission charge rate
RATEvoc – volatile organic compounds emission charge rate
$REVel_t$ – annual revenues from electricity sale
$REVheat_t$ – annual revenues from heat sale
SUBSIDY – one-time investment subsidy

1 BASIC CONCEPTUAL MODEL

This chapter provides an overview of the main objects and factors in CHP plant operating activities as well as their interrelations that affect the plant's viability. The descriptions of components and interactions are versatile and could be applicable to the majority of CHP plants.

The flowchart of the basic conceptual model is shown in *Figure 1.1*. The description of the components is provided below.

1.1 Energy consumers

A CHP plant has to be built in the location where energy consumers/purchasers and connections with them are available. These are the main conditions which define the possibility to build a CHP plant in a specific location.

The energy consumers' demand for heat, steam, cooling and electricity, parameters of the consumed energy as well as energy consumption profiles define the technical parameters of CHP plant components and operating strategy of the plant.

Thus it is very important to define the consumer/purchaser energy demand.

The consumer energy demand cannot always be satisfied by a CHP plant. A good example here is a large district heating network, which involves different heat producers. Other producers can provide heat in case of the CHP plant's planned shutdown, failure or inefficient operation mode.

Mainly the same principle is applicable to electricity production where the CHP plant (especially based on renewable fuels) operation is defined by the heat consumer demand, but not by that of electricity consumers.

The opposite situation could occur in case of the so-called "island mode" of CHP plant operation. In this case only the CHP plant equipment is to cover the consumer energy demand while it should be primarily supplied with the necessary amount of energy. Other energy sources produced in CHP plants are considered as secondary products. The primarily supplied energy sources need often a backup energy production unit, which could be an integrated part of a CHP plant. For district heating areas the backup unit could be a peak load boiler, which can provide certain amount of heat during the failure of the CHP basic load unit.

The estimations of energy consumers/purchasers energy supply conditions influence the selection of CHP plant equipment, capacities and amount of produced energy.

The next chapter provides information about the main properties of energy loads which are important for the CHP plant planning.

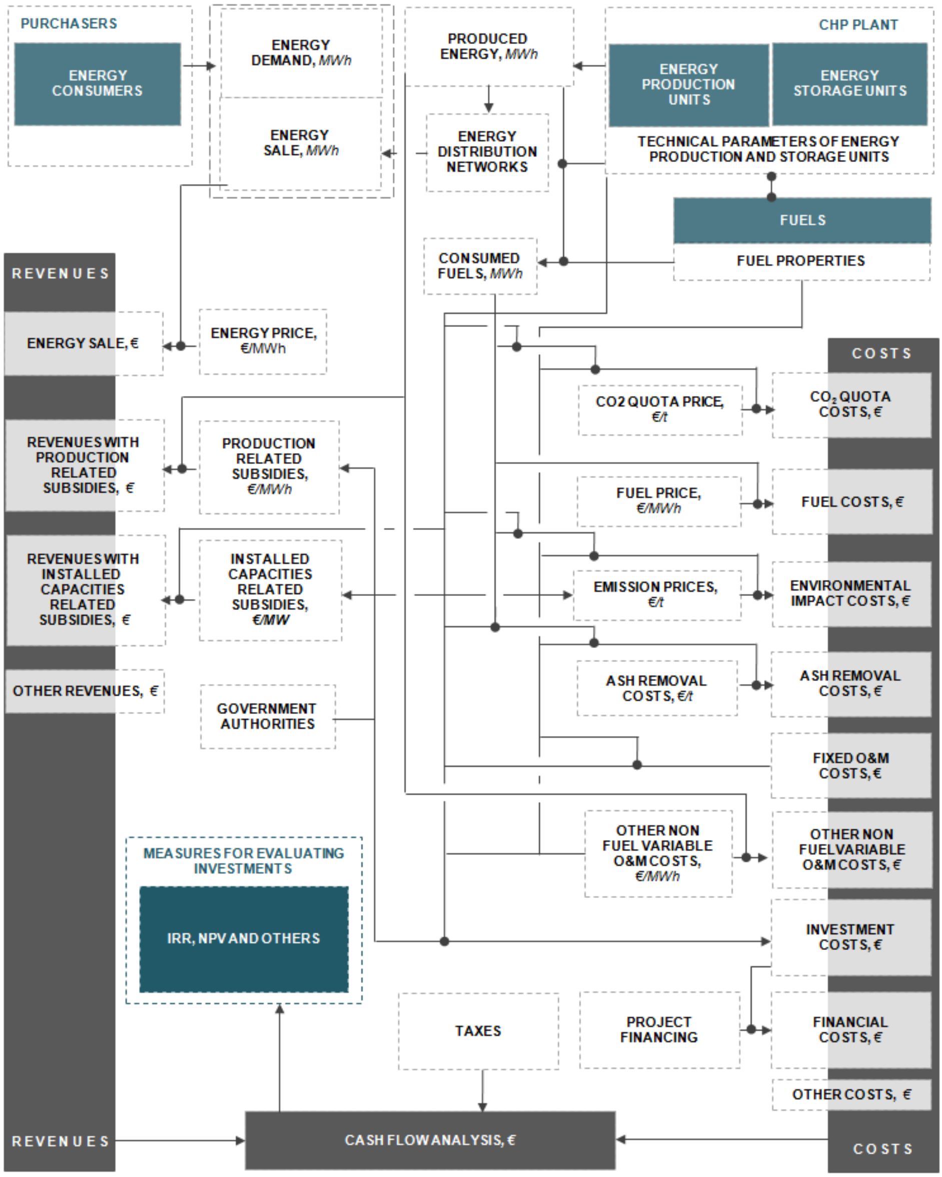


Figure 1.1Basic conceptual model of a CHP plant

1.2 Energy demand

The heat demand can be established in several ways. Regarding the consumers connected to the energy networks to whom energy has been supplied for many years already with their actual heat consumption being measured, the energy demand of previous years can be taken for the basis.

If the statistic data is not available, the energy demand and load duration curve has to be calculated. This energy load simulation approach is appropriate for planning the demand of new energy consumers as well as old ones where no continuous measurements of energy consumption have been executed.

The main energy source to be estimated is heat. For the consumers who are going to be connected to the DH system in the near future, the project documentation related to heat supply can be used for establishing the heat demand in case of a new building. When the new consumer is the one who has used the local heating before, the data on the earlier consumption can be used. For the consumers who are going to be connected to the system later, there is a simpler way for estimating their demand based on the volume of buildings, number of inhabitants, etc.

It must be underlined that when estimating the future demand based on the earlier consumption level, evident decrease of heat load in the future has certainly to be taken into account. The reason for the reduction can be additional thermal insulation of buildings, more flexible control of heat consumption, introduction of energy saving appliances and changes in the consumption habits, etc. The rising prices (both heat and water), and for example, installation of water meters in each flat can also reduce consumption.

The energy demand can be defined when the data (previously measured or calculated) on the load is available for certain periods of time. The graphic appearance of data is called an energy load graph. The ordered energy load graph is called a heat load duration curve.

1.3 Fuels

The fuel selection is an important part of CHP plant planning. Thorough the investigation of fuel availability, the price as well as properties of available fuels will help to select the most reasonable fuel type for the CHP plant expansion and avoid possible fuel related problems. The main fuel selection related properties and issues are briefly described below.

Sulphur content is an important component of fuel. Fuel firing causes sulphur oxidation and emission of sulphur oxides (SO_x) into the environment. High sulphur content can cause low temperature corrosion of flue gas ducts, air pre-heaters and stack. In the course of selection of CHP plant components it is important to ensure that the temperature on any surface in contact with the combustion gases will not fall below their acid dew-point temperature (about 120 – 140^{o}C), otherwise low temperature corrosion and acid smut emission may occur. The higher cost of equipment as well as maintenance should be considered for the use of fuels rich in sulphur.

The chlorine content in the fuel could also have impact on the corrosion of heat transfer surfaces. The presence of corrosive gases such as chlorine and hydrogen chloride, corrode the boiler tubes, particularly those operating above 400^{o}C, resulting in tube thinning and failure.

The high *fuel moisture content* decreases the lower heating value of fuel. The use of wet fuels increases the volume of fuel gases and worsens the fuel ignition. The boilers are optimized for a specified fuel moisture content and designed for certain moisture variation. The usage of fuel with the lower moisture content than determined by the boiler manufacturer may cause significant damage on heat transfer surfaces and in the case of grate boiler damage the grate. High moisture content increases the danger of capacity drop and boiler shut-down. In this case the combustion mode fails, boiler cannot reach the calculated capacity and steam parameters, the electrical and total efficiency of the CHP plant decrease.

High ash content in fuels increases ash handling costs, which show linear dependence on the ash content. The settled particles worsen heat transfer from flue gases to the heat transfer surfaces, increase the temperature of fuel gases and decrease the efficiency of plant operation. The particles moving with fuel gases increase the erosion of surfaces. The high ash content can lead to fast blinding of heat transfer surfaces. To reduce the negative impact of high ash content, more efficient (and more expensive) heating surface cleaning systems should be used.

Ash melting properties define the boiler design. It is important that under different boiler operation modes, there are no zones on heat transfer surfaces where the temperature exceeds the ash melting point. The melted ash forms a glassy slag area. The cleaning of glassy slag with the boiler surface cleaning systems during operation is not effective. The glassy slag areas decrease heat transfer and could significantly decrease the boiler efficiency.

When ordering/designing a boiler, it is important to know the fuel properties. In the case of co-combustion of different fuels, it is important to know the ratio as well. If it is assumed to combust a local fuel with the melting characteristics not determined; it will be necessary to provide tests and define them.

If the boiler is designed for one fuel, it will be important to know that co-combustion with some other fuel may cause serious boiler slagging. The reason for this is the melting point of ash produced during co-combustion. It is almost always lower than the melting point of the fuel with the lowest melting point of co-fired fuels.

1.4 CHP technologies

There are numerous CHP technologies that can theoretically be used in CHP systems. Some of them are still under development, their use is technically (the commercial use assumes high availability, which is not guaranteed) or/and economically (high price or/and high maintenance costs) not feasible. Others are market ready and competitive CHP technologies. The main CHP technologies, their typical nominal heat output capacities and roughly estimated annual heat productions (assumed 4500 hours of operation divided to the annual nominal heat capacity) are shown in *Figure 1.2.*

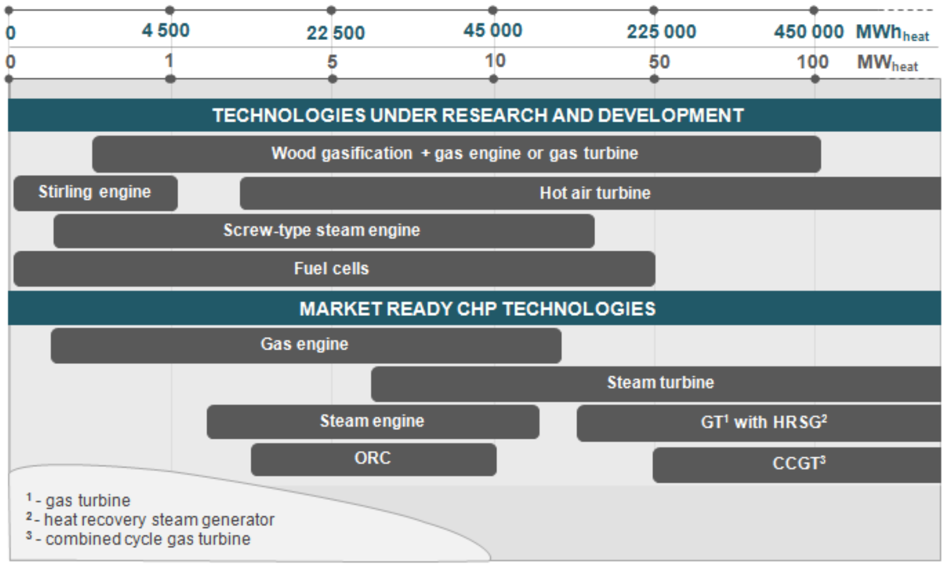


Figure 1.2 Main prime mover CHP technologies

One of the most promising technologies is the use of wood gas in gas engines. The advantage of this technology is a possibility to achieve relatively high electrical efficiency in district heating networks with a relatively low heat demand by using local renewable fuels (mainly wood). The main problems of wood gas utilization in gas engines are the availability of technology and its price. The high soot and tar content of wood gas requires effective treatment facilities. The cheap treatment facilities do not allow achieving the high quality of wood gas, and as a result frequent gas engine breakdowns occur (low availability and high repair costs). Reaching the high and stable quality of wood gas anticipates expensive treatment facilities; thereby the implementation of this technology becomes unreasonable.

The energy load variations, as well as parameters of the energy to be produced influence the selection of technology. As an example, high pressure steam can be produced by using of a steam turbine or CCGT technology. The heat recovery from the flue gases of gas engine exhaust allow producing low pressure (basically lower than 10 bars) steam while the ORC technology is designed for the hot district heating water production only.

Each technology is characterized by the following main indicators:

- Capital costs;
- Efficiency at nominal load;
- Change of efficiency when working at partial load;
- Fixed and variable operating and maintenance costs.

A brief description of mostly used market ready CHP technologies is provided below. The description and flowcharts are based on the assumption that no steam is delivered to consumers.

The steam turbine technology has a classical design regardless of fuel type. The main equipment of the plant is a steam boiler and steam turbine with a generator. The heat generated as a result of fuel combustion is used for steam generation. The higher is the produced steam temperature and pressure, the higher electrical efficiency could be achieved. Steam expands in a steam turbine and does mechanical work (spinning the generator).

The flowchart of a steam turbine based CHP plant is shown in *Figure 1.3.*

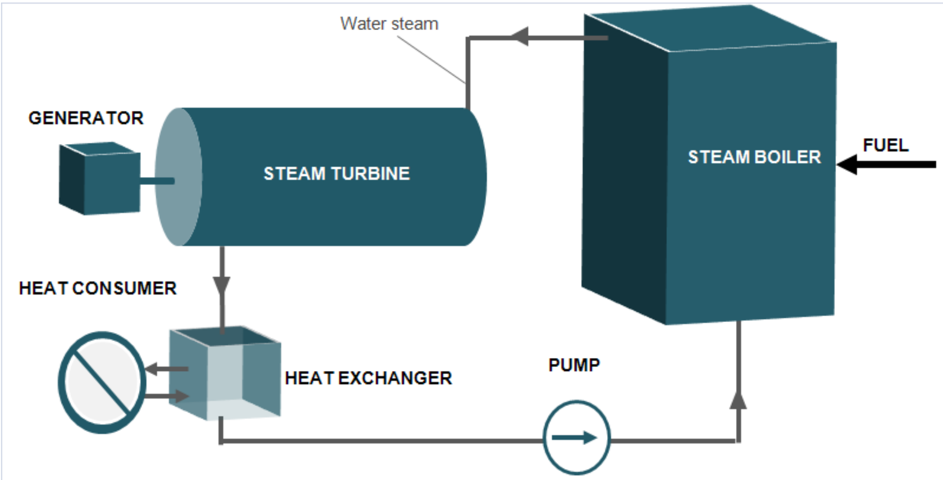


Figure 1.3 Flowchart of a steam turbine based CHP plant

The diagram above shows a backpressure steam turbine based CHP plant, which is mainly used for hot water production in a district heating area. Another type of steam turbine used in CHP applications is called an extraction turbine. In these turbines, steam is extracted from the turbine at some intermediate pressure. This steam can be used to meet the facility's steam need. The remaining steam is expanded further and condensed.

The common capacity of steam turbines ranges from 1 to 500 MW_{el}. The electrical efficiency of steam turbine based CHP plants is mainly in the range of 9 to 35%. The total efficiency is generally above 80%.

The steam engine operation process is mostly similar to a steam turbine based CHP plant where the turbine is replaced by the engine (*Figure 1.4*).

The steam engine capacities are in the range of 0.1 to 1.5 MW_{el}. Mainly under 1$MW_{el,}$ the steam engine performance parameters are slightly better than for steam turbines with the same nominal capacities.

The final decision regarding the selection between a steam turbine and steam engine depends on concrete characteristics of the proposed units and site conditions (heat parameters, heat demand and shape of heat load profile).

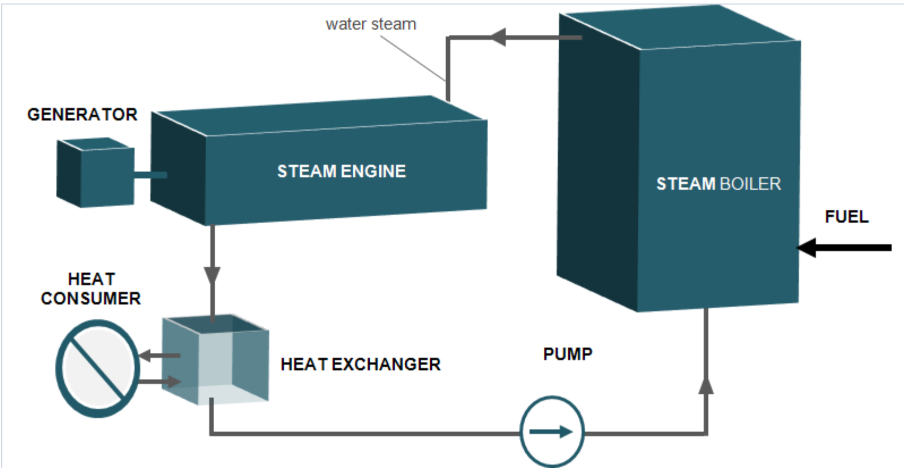


Figure 1.4 Flowchart of a steam engine based CHP plant

The difference of ***Organic Rankine Cycle (ORC)*** process from the water steam cycle is that heat is transformed into electricity by the thermal oil and organic heat transfer medium cycle. The ORC units are industrially produced for ORC plants. An ORC unit consists of the following main components:

- Heat exchanger for heat transfer from thermal oil to heat carrier (an organic fluid);
- Steam turbine driven by the organic heat carrier and generator;
- Heat exchanger for heat transfer from the organic heat carrier coming from a steam turbine to heat consumer;
- All necessary piping and automation devices installed.

The flowchart of an ORC unit based CHP plant is shown in *Figure 1.5.*

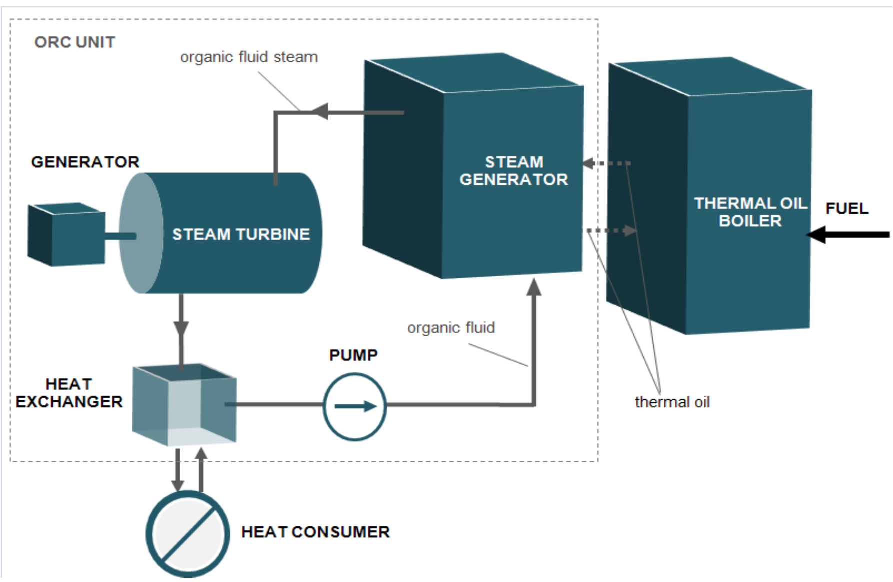


Figure 1.5 Flowchart of an ORC unit based CHP plant

As long ago as approximately 10 years, the ORC based technology was rarely used. But because of some pros in comparison to the water steam cycle and successful technical implementation of ORC theory, it has become worth of consideration and competitive for 0.25 – 2 MW_{el} CHP applications.

The main pros of CHP plants based on the ORC technology in comparison to the water steam based technologies are:

- Thermal oil operates under lower temperature;
- Organic fluid is not corroding, the turbine lasts longer;
- Organic fluid treatment is not necessary;
- Wide operation range (15 – 100%);
- Practically constant efficiency at the partial load.

The electrical capacity of ORC plants is about 15%. The total efficiency of an ORC plant is usually higher than 80%.

Gas engine based CHP plants (*Figure 1.6*) are widely-distributed in the world, and particularly in Estonia. The main fuels for gas engines are natural gas and light fuel oil. The extended use of biofuels in energy production stimulates research work in the field of biomass gasification (especially wood gasification) and wider use of the produced biogas in gas engines.

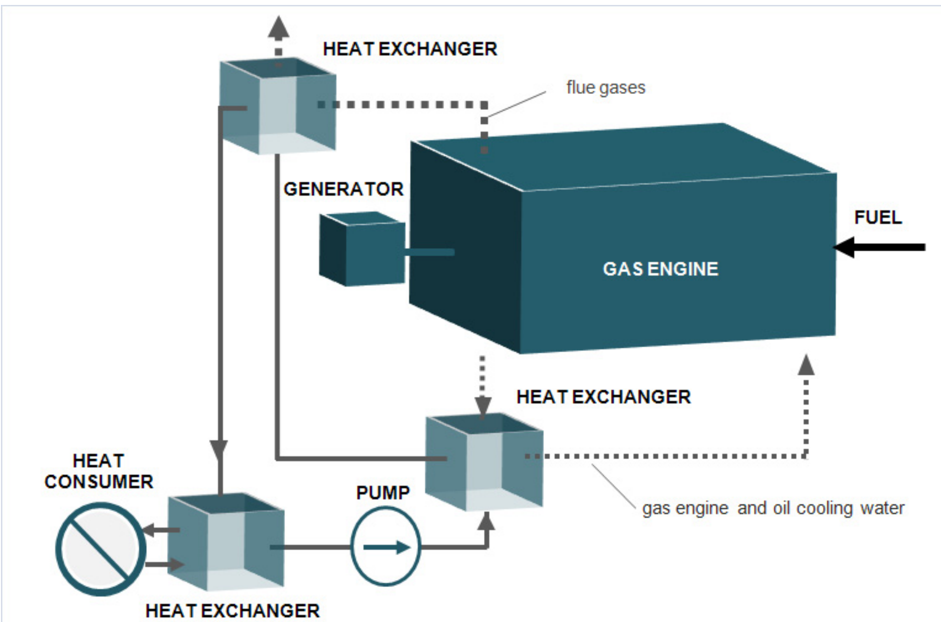


Figure 1.6 Flowchart of a gas engine based CHP plant

Electricity is produced by the generator connected to the gas engine. The district heating water is heated with recovering the heat from the flue gases of gas engine, engine cooling water circuit and lubricating oil circuit.

These plants are generally manufactured as fully packaged units that can be installed within a plant room or external plant compound with simple connections to the sites gas supply, electrical distribution and heating systems.

The gas turbine plant with a heat recovery boiler *(simple cycle gas turbine CHP plant)* is such a plant where hot flue gases from the gas turbine go to the heat recovery boiler (water boiler). Heat from the recovery boiler is transferred to heat consumers. The additional heat could be added to the heat recovery boiler by the extra fuel to be combusted in the boiler.

The simplified diagram of the gas turbine plant with a heat recovery boiler is shown in *Figure 1.7*.

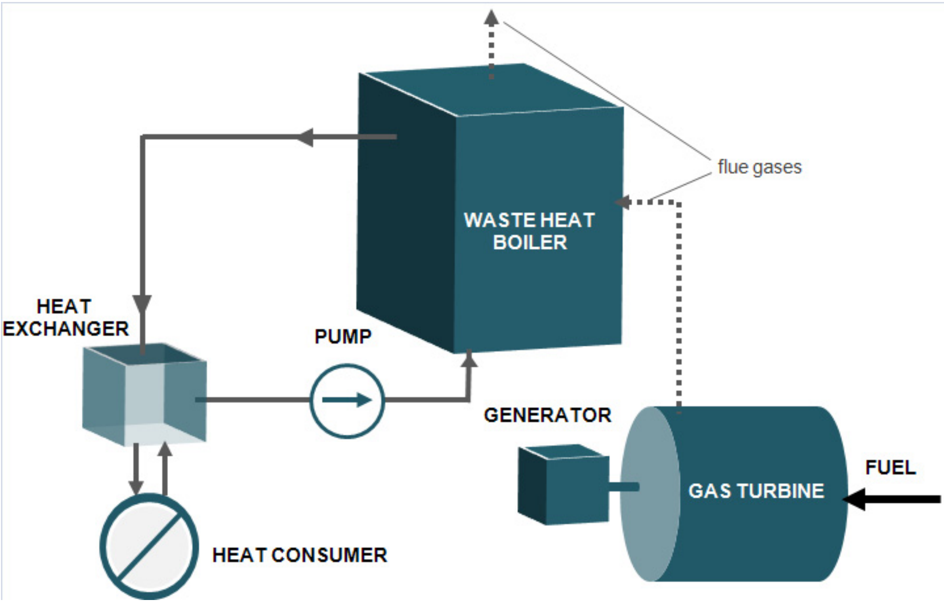


Figure 1.7 Flowchart of a simple cycle gas turbine based CHP plant

The electrical efficiency of this kind of plants is mainly 30 – 36% and depends on the efficiency of gas turbine. The overall efficiency of simple cycle gas turbine CHP plants is typically above 80% (heat output is higher than for electricity).

The combined cycle gas turbine plant (CCGT) differs from the simple cycle technology by heat recovery from the gas turbine exhaust gases for electricity production. The CCGT plant is such a plant where hot flue gases go to the heat recovery steam generator (HRSG). The steam produced in HRSG moves to the steam turbine where additional electricity is generated. The steam discharged from the turbine is used for heat production.

The CCGT plant electrical efficiency is about 45 – 60%. It depends on the electrical efficiency of gas and steam turbines. The total efficiency of CCGT plant is about 85 – 90% where the share of produced electricity is mainly higher than that of heat.

The CCGT plant combines high electrical efficiency and flexibility of operation. The bypass after the gas turbine allows changing electrical load without any impact on the heat output.

The CCGT plant flowchart is shown in *Figure 1.8*.

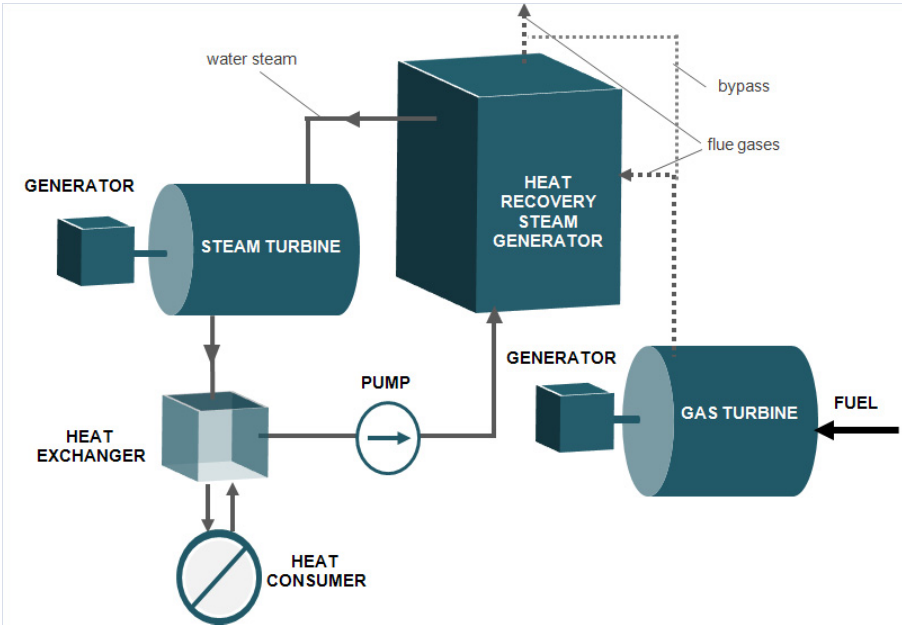


Figure 1.8 Flowchart of a combined cycle gas turbine based CHP plant

It is important to mention that a lot of research and development work is being carried out in optimizing and improving the technology characteristics. Thereby depending on the targets and working conditions, the market can provide some hybrid technologies, which could significantly differ from the above mentioned main technology designs. As an example, to increase the electrical capacity of gas engines some offerers can propose a combination with the ORC process where hot flue gases from the engine go to the oil boiler that is connected to an ORC unit. It is important to evaluate all available alternatives and select the most cost efficient solution.

1.5 CHP plant costs

For the evaluation of the economic feasibility of investments it is useful to consider the CHP plant O&M costs separately as fixed and variable costs. The fixed costs include costs that do not depend on heat output, and are approximately proportional to the nominal value of the plant. The distribution of costs into fixed cost and variables is not clearly defined and may differ from case to case. As an example, some time ago the environmental costs were considered fixed costs, due to the negligibility in comparison with total costs. For the time being the environmental costs have higher share in total costs and are mainly considered variable costs.

The main costs of a CHP plant are discussed below.

1.5.1 Environmental costs

The environmental impact of combustion plants through the emission of sulphur dioxide, nitrogen oxides, carbon oxide, volatile organic compounds, solid particles and heavy metals into the ambient air depends on combustion technologies, flue gas cleaning technologies, control devices as well as capacities and properties of the fuels burnt in the plant.

To estimate the environmental costs it is important to know the amount of emitted pollutants during the period of time and pollution charge rates upon the emission of pollutants into the ambient air.

The emissions can be estimated on the basis of direct measurements (the existing plant with appropriate gauges) and/or calculations.

The rules to calculate emission factors and values for the pollution charge rates upon the emission of pollutants are mainly defined in the state acts and regulations.

1.5.2 CO_2 quota costs

The European Union (EU) Directive 2003/87/EC of 13 October 2003 has established a scheme for greenhouse gas emission allowance trading with the purpose to:

- Induce society to use resources more effectively and encourage innovations;
- Increase awareness of CO_2 damage from fossil fuel combustion and their cost to society;
- Improve fulfilment of the obligations taken under the Kyoto Protocol for reducing greenhouse gas emissions.

The CO_2 quota trade rules are applicable for the countries which have ratified the Kyoto Protocol, an international agreement on climate regulations.

The CO_2 quota trade is a symbiosis of power engineering and financial world, which is important for all energy producers and other industries involved to the quota trade.

The first period of trading lasted from 2005 to 2007 when the CO_2 quota trading was mainly conducted only between EU Member States. The emissions quota trading scheme 2005 – 2007 was like a training stage. [4]

In the second period of trading (2008 – 2012) the CO_2 quota trade rules assume that a combustion plant is not obliged to buy or sell CO_2 quotas if the CO_2 emissions do not exceed the allocated quantity. All combustion plants with a rated thermal input of less than 20 MW of capacity do not take part in quota trades.

Since the rules for *the third period of trading* which will apply after the year 2012 are not distinctly clear yet, it is quite complicated to forecast the CO_2 quota price. In outline, third period means cancellation or significant reduction in the CO_2 quotas allocated to EU countries and putting into operation general exchange for trading in CO_2 quotas.

In spite of not clearly defined trading rules for the period after 2012 it is important to take into consideration risks or opportunities related to possible affects of CO_2 trading to CHP plant economics.

CO_2 quota costs are proportional to a fuel-specific CO_2 emission factor by the equal CO_2/t quota price.

1.5.3 Ash handling costs

Ash handling costs depend on:

- Fuel ash content;
- Percentage of ash to be handled by the ash removing system;
- Water content in ash which determines the final weight of ash to be disposed of;
- The class of ash to be disposed of (domestic waste, dangerous waste etc.).

The classification of ash depends on the composition and properties of ash particles, which mainly depends on the fuel composition and combustion technologies. As an example, fly ash from the mass burn waste-to energy plants is commonly classified as a dangerous waste due to the high content of heavy metals. The disposal price per mass unit of dangerous waste could be significantly higher (more than ten times) than for a domestic waste disposal.

In the case of wet ash removing technology the wet ash density is much higher than in the case of implementing the dry ash removing technology (ash removal costs are higher). But the wet ash removal system can reduce the risk of fire caused by the unfinished burning particles when removing ash from the ash container into fields. Besides, in the case of wet ash removal, there is no dust in the air and ash is always cold – that contributes to a longer service life of the equipment.

Ash handling costs can form a significant part of CHP plant O&M costs. It is important to carefully consider the ash types formed during the energy production process, amount of ashes to be disposed and the price of ash disposal for each type of generated ash.

1.5.4 Project financing costs

The project financing costs include all costs which are necessary to plan, construct and put a CHP plant into operation. The capital structure of the costs may consist of equity capital, debt and subsidies. The proportion of debt and equity in the capital structure of a firm will vary with the investment opportunities and market structure within which firms operate.

All lenders charge interest. The rate charged for particular loans depends upon both the maturity (and length) of the loan and its risk. The relationship between interest rates and maturity is called the term structure of interest rates.

All other things equal, the typical relationship between interest rates and loan maturity is positive, i.e. longer term loans bear higher interest rates. [5]

The subsidies, as a percentage of total costs, or as a predefined amount of money per kW installed is an important supporting mechanism which decrease the amount of equity and/or debt and makes project more competitive. [6]

1.5.5 Other costs

In addition to above mentioned costs, the following costs should be considered (the list of costs is formed based on the cost breakdown proposed by the Estonian Competition Authority):

- Purchased heat, electricity, chemicals;
- Consumed water and sewerage costs;
- Land Use Tax;
- Government duties;
- Operation and maintenance of the equipments and buildings;
- Office building and rooms related costs;
- Technical consultancies and legal advices;
- Corporate fees;
- Transport costs;
- Telecommunication costs;
- Insurance costs;
- Office costs;
- Labour costs, etc.

1.6 Revenues

The revenues of the CHP plant are mainly formed from selling the produced energy. The amount of produced energy and that of sold energy are not always equal. As an example, the CHP plant heat output decreases due to the heat loss in the district heating network, the consumers pay for the used amount of heat. As a rule, at the same time the amount of sold electricity does not take into account electricity transmission and distribution losses. Thereby it is important to establish the right amount of energy, which is correct for the revenue calculations and applicable to certain energy price.

Energy price or feed-in tariff can be constant for a certain relatively long period of time (fixed feed-in tariff for a year) or variable (day/night tariffs, seasonable tariffs, Nord Pool electricity price fluctuations, etc.). In the case of co-combustion of biofuels and fossil fuels in CHP plants the amount of electricity subsidized by available feed-in tariffs should be defined.

The revenues from energy sale are defined by the amount of sold energy and an appropriate energy price. The energy price can be formed in the course of competitive activity or matched by the appropriate government authorities.

The revenues with production related subsidies depend on the amount of energy to be subsidized and the subsidy tariff. The types and the values of subsidy tariffs vary by country. The energy production related subsidies are mainly applied to the electricity production from RES or in the CHP plants working in efficient cogeneration mode. The main point of electricity production related subsidies is to increase competitiveness of RES and CHP production and promote its move toward grid parity.

The heat production related subsidizing is not widely used to support the expansion of CHP plants. But the use of this supporting method is under consideration in some countries. [7]

The revenues with fixed subsidies are mainly described as a percentage of total costs, or as a predefined amount of money per kW installed. Usually, the fixed subsidies are used in the form of a single sum of money to decrease the amount of equity and/or debt and make the project more competitive.

All other CHP plant activities related revenues, which have not been specified above should be taken into account.

1.7 Measures for evaluating investments

The profit can be understood and treated differently - in many countries the profit is a financial source used for investments, technology upgrading, mitigation of environmental impact and improvement of labour conditions. The owner's profit from the power company's activities, i.e., dividends from the shares, may be either allowed or prohibited.

In some countries (as an example in Denmark) the district heating companies are usually owned by local authorities and earning profit for the owner is forbidden. In other countries most of DH companies are privately owned and the owners' interest in earning reasonable profit provides better management. [8]

To evaluate the profitability of the project at the planning level different measures for evaluating the investments could be used. The mostly used cash flow based measures are:

- Net Present Value of Cash Flows (NPV);
- Internal Rate of Return (IRR);
- Payback time.

The selected measures for evaluating investments should be clear for investors and be determinative for decision making. If the CHP plant profitability calculations are intended for the investors (co-financing), government authorities (for subsidizing, etc.) or banks (to get a loan), authorized in these organizations measures should be applied.

2 SIMPLIFIED CONCEPTUAL MODEL

The previous chapter described main objects and factors in the CHP plant operating activities affecting the plant feasibility; a basic conceptual model of CHP plant was composed.

This chapter concerns the development of a simplified conceptual model by filtering out the data not valid or non-typical for Estonian conditions from the basic conceptual model and specifying some of the data natural for the Estonian energy sector. The composition of simplified conceptual model is based on the analysis of current legislation, available information and experience obtained during the participation in CHP plant related pre-feasibility and feasibility studies for different locations in Estonia (e.g. Tallinn, Tartu, Pärnu, Jõgeva) as well as in other energy related projects (see Consulting Assignments in Appendix 2).

2.1 Energy consumers

The main potential CHP developers are district heating networks in the cities and municipalities in Estonia. *Figure 2.1* shows their distribution by the annual heat demand. The locations where CHP plants have already been constructed or are under construction, as well as in the state of active development are marked separately. *Figure 2.1* reflects well known principles where the consumers with higher annual heat demand are more preferred.

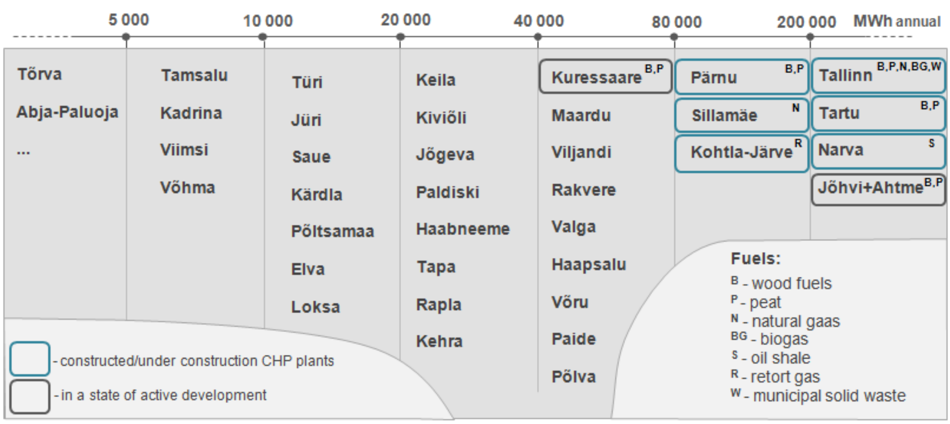


Figure 2.1 Distribution of Estonian cities and municipalities by the annual heat demand

The CHP expansion in the industrial sector is also considerable. The most attractive projects involve the enterprises with a stable heat load demand (woodworking and pellet production companies, etc.). The companies with a variable process heat demand (dairy industry, bakery industry) are more complicated for CHP plant developing due to the more complex sizing and optimization of energy production.

The interest of developers to the CHP unit based district heating/cooling option can be considered negligible. It is assumed with taking into account the above mentioned circumstances that the average energy consumer is a district heating network or industrial enterprise consuming heat (hot water or low pressure steam). The electricity is mainly sold on the market (Nord Pool). The Estonian transmission system operator Elering is obligatory to by all electricity produced based on renewable energy sources, including biomass.

2.2 Energy demand

On the average, the energy demand of consumers who are promising for the CHP expansion in Estonia is about 5000 – 60000 $MWh_{heat,}$ including the heat loss in heat distribution systems where the average heat loss is 20%. [9]

The electricity market is more globalized and at the moment there are no limitations to electricity production as a result of insufficient demand. Besides, regarding some studies, a negative energy balance is expected to emerge in the Baltic States. [10]

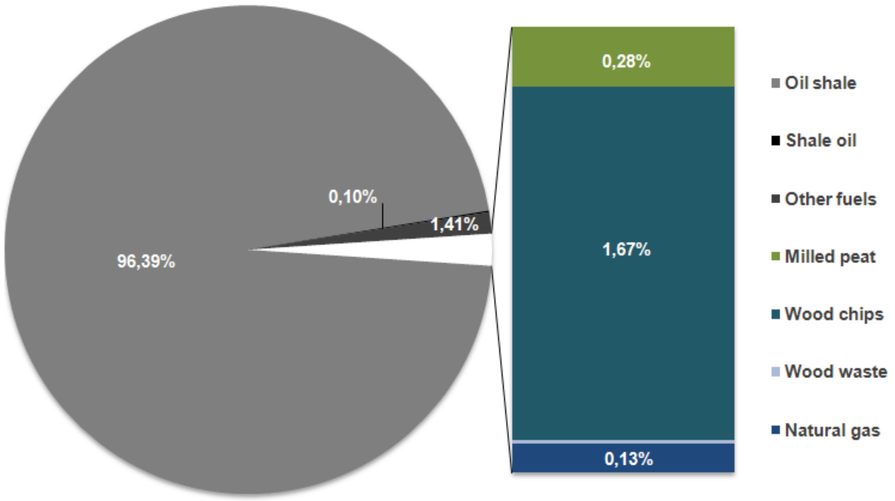
2.3 Fuels

The Estonian energy sector is mainly based on oil shale, which is one of the main factors providing energy independence for Estonia. About 96% of electricity is produced from oil shale in comparison to other fuel types.

The main fuels used for electricity production in Estonia are: oil shale (the major part), peat, woodchips and natural gas (see *Figure 2.2*). Oil shale processing products (shale oil and shale oil gas) are also having their share in electricity production. Oil shale gas is used as a main fuel or additional fuel in oil shale boilers. Shale oil products are mainly used as a firing-up fuel.

Oil shale has high ash content (about 45%) [11] and this makes the fuel transport and ash removing costs high. Besides, the oil shale based market ready efficient combustion technologies for less than 50 MW_{fuel} are not available. Oil shale gas is more flexible, but the use of the gas depends on oil processing. The utilization of oil shale gas is of local value. The technologies for oil shale gas compression and transportation are not being used. There is no practical interest in the oil shale gas use in CHP systems outside the oil shale processing regions. The price of oil shale products is variable and remains close to that of crude oil products. At present the oil shale price (~35 €/MWh_{fuel}) [12] is not competitive with other domestic renewable fuels and is almost the same as that of natural gas, which is a cleaner and more flexible fuel.

For the time being, a few waste burning projects have been studied. One of them developed by the Estonian state owned energy group Eesti Energia has signed an agreement on building a waste incineration unit (17 MW_{el} and 50 MW_{heat}) at the Iru cogeneration plant just outside Tallinn. About 100 M€ plant would burn annually up to 220000 tons of waste created in Estonia and its approximate operation start time is in 2012. This plant will utilize 2/3 of the waste suitable for energy use, which is deposited into Estonian landfills each year. The further CHP expansion based on unsorted waste incineration is limited to fuel (waste) deficiency.



Other fuels: The shale oil gas and biogas, black liquorer fuels are other fuels.

Figure 2.2 Fuel consumption for electricity production in 2009 [13]

Taking into account the above mentioned consequences the use of oil shale and oil shale processing products in CHP expansion is unlikely. The use of burning waste is limited to its deficiency. The most suitable fuels for CHP plants are woodchips, peat and natural gas.

2.4 CHP technologies

During the last 2 years not many CHP plants working on woodchips and peat were built in Estonia. A few of biomass CHP plants are under active development. All of them are planned to be built or reconstructed in major Estonian cities and are based on the backpressure steam turbine technology. At the same time the feed-in tariffs as well as possibilities to get grants for expanding the CHP implementation and use of renewable fuels makes CHP expansion more attractive for the locations with lower heat demand.

The steam turbine technology is classical for CHP plants. But in relatively small-scale boilers and district heating systems the use of steam turbines is related to economically less efficient operation (commonly higher specific investment costs, O&M costs and lower electrical efficiency). There the use of other alternative CHP technologies could be preferable. Taking into account the average capacities of potential CHP systems (see Chapter 2.1) and level of market-readiness (*Figure 1.2*) the following CHP technologies are considered:

- Steam turbine/steam engine;
- Gas engine;
- ORC technology.

2.5 CHP plant costs

The CHP plant costs can be defined by calculations, assumptions or considering the analogy with similar technologies, capacities, fuel types and other plant parameters. It is important to sort out the major costs, which could be calculated with or without considering the slight impact of assumption on the calculation results. Other costs have to be estimated based on an analogy with similar units or assumptions. Taking into account Estonian conditions, the CHP plant major costs will be described below.

2.5.1 Environmental impact costs

To estimate the environmental costs it is important to know the amount of emitted pollutants during the period of time and the pollution charge rates upon the emission of pollutants into the ambient air.

Regarding [14 and 15], the emissions of sulphur dioxide, nitrogen oxides, carbon oxide, volatile organic compounds, solid particles and heavy metals generated by combustion plants and emitted into the ambient air shall be determined on the basis of direct measurements and/or calculations. During the planning period the emissions of pollutants should be determined based on calculations. This method takes into account different combustion technologies, flue gas cleaning technologies, control devices as well as capacities to define the emission factors of pollutants.

Pollution charge rates upon emission of pollutants into the ambient air are defined in [16] where the charge rates are given until the year 2015.

2.5.2 CO_2 quota costs

The trade rules of CO_2 quota are applicable for Estonia, as a country that has ratified the Kyoto Protocol. Trading rules for the period after 2012 are not clearly defined, so it is important to take into consideration the risks or opportunities related to the possible impact of CO_2 trading on CHP plant economics. It is assumed that the CO_2 costs are equal to the amount of CO_2 emitted multiplied by the CO_2 quota price. The computations of fuel-specific CO_2 emission factor for calculating the amount of CO_2 emitted are defined in [15]. Regarding [17], if CO_2 trading will be prolonged after 2012, the CO_2 quota price level could range from 20 up to 35 €/t. It is important to mention that according to the latest available data [18], the installations with a total rated thermal input exceeding 20 MW are not involved to CO_2 quota trade.

2.5.3 Ash handling costs

The ash handling costs depend on ash composition, fuel ash content, percentage of ash to be handled, and the type of ash removal system. In the case of wet ash removal technology, the wet ash density is much higher than in the case of implementing the dry ash removal technology.

At the moment the disposal of ash from the biomass and peat consuming CHP plants in Estonia does not differ from the domestic waste disposal (disposal prices and conditions). Regarding the information obtained from different landfill owners, the average ash removal costs (ash transportation to a landfill and storing) in Estonia comprise 45 €/t for the year 2010.

The ash content of peat is 5%. The average calorific value is 3.3 MWh/t [19]. The ash content of woodchips is 1% with the calorific value being 2.4 MWh/t. Natural gas based combustion does not emit any ash.

2.5.4 Project financing costs

There a different capital structure compositions and financing methods in energy projects. The share of debt in the project depends on the available equity capital and credit conditions. The subsidies in the capital structure decrease the amount of equity and/or debt and make the project more competitive.

It is also important to mention a regulation, which assumes grant payments of fewer than 2 MW_{el} biomass CHP plants for up to 50% from the eligible expense assistance [20]. Enactment of this regulation is an extremely important step for the expansion of small-scale CHP plants. At the same time the application of this regulation is limited to the availability of funds. The latter depends on the amount of CO_2 quota sold and terms of sale. Since it is unfeasible to expect guaranteed utilization of the above mentioned grant payments, it becomes unreasonable to take them into account during the plant planning. Therefore the grant payments are not considered in this study.

2.5.5 Other costs

Other CHP costs cannot be calculated by the accepted computation methods and available data. They should be estimated based on assumptions or by the analogy with the same technology and similar capacity, fuel type and other plant parameters.

3.6 Revenues

Basically, in Estonia a CHP plant gets the revenue from heat and electricity sale and electricity related subsidies. The description of these components is provided below.

2.6.1 Electricity sale

Estonia has time until December 2012 to fully open its electricity market; however, 35% of the market was opened to large consumers in January 2009.

An important step for establishing free market conditions was taken in spring 2010 with the introduction of Estonian price area in Nord Pool Spot electricity exchange. The connection between Estonia and Finland (the Nord Pool market) is available through the sea cable Estlink1, which allow 350 MW connection capacities. To establish more tight linkage between the Nordic and Baltic countries a new sea cable Estlink2 is planned. The electricity price for CHP planning calculations should reflect the situation in Nord Pool Spot Estonia with taking into account the average price formation related tendencies.

2.6.2 Heat sale

According to the District Heating Act, heating undertakings that produce heat in the process of combined heat and power production should get approval for the heat price in every district heating area from the local government or Estonian Competition Authority. It means that during the planning process of a CHP plant, it is not correct to define the income from heat sale using a random heat price. The maximum price of heat shall be set such that:

- The necessary operating expenses, including the expenses incurred upon the production, distribution and sale of heat, are covered;
- Necessary investments for the performance of operational and development obligations are made;
- Environmental quality and safety requirements are met;
- Justified profitability is ensured.

To realize the above-mentioned procedure for the approval of maximum prices for heat, a heating undertaking shall keep separate accounts for the production, distribution and sale of heat and that for the areas of activity not related to such activities. According to the District Heating Act, a combined heat and power plant should separate the costs for heat and power production from one CHP facility, which vary significantly depending on the CHP technology and cost separating methodology. As an example, the pieces of equipment in a CHP plant based on the steam turbine technology can be used for heat or power production only. The main equipment (a boiler, steam turbine, fuel handling equipment) is used both for heat and power production, which brings about a necessity to divide equipment depreciation between the joint products. A very important issue concerns the fuel consumption for heat and power production separately, because at the moment there is no approved methodology for that in Estonia. Basically, there are some well-known methodologies to separate the share of fuel for heat and electricity production. These methods differ from each other by fuel dividing methodology and achieved results.

For the time being the Estonian Competition Authority uses the Reference Boiler House Method. This method assumes that the price for heat produced at the CHP plant maximum heat price is not higher than the price of heat produced from the same fuel(s) in the similar capacity boiler plant [21]. This method assumes that a heat consumer will not pay more than for the heat produced in the boiler plant. At the same time the investor has indicative heat price and the effective investment in the combined CHP generation can allow higher profit from the investments.

So for the time being, in the CHP plant modelling it is reasonable to use the heat limit price at the same level as for similar boiler plants. The use of higher heat cost may give overrated recoupment of capital investment.

2.6.3 Subsidy mechanisms

The subject which needs special consideration is the formation of energy related subsidy mechanisms (excluding one-time investment subsidies).

The EU regulations and local Estonian legislation influence policy making in the field of electricity production. According to the EC Directive 2001/77/EC on the promotion of electricity produced from renewable energy sources in the internal electricity market, an indicative target of 21 percent was established for the share of renewable energy sources in the total energy consumption of EU members by 2010. After the Commission's re-assessment in 2008, however, the existing policies and measures were estimated to lead to a 19% share of renewable energy in the EU's electricity production by 2010. The directive also defines indicative targets for each member state; the figure for Estonia was 5.1% by 2010. The EU has also adopted measures to promote combined heat and power generation, which are mainly based on the EC Directive 2004/8/EC on the promotion of cogeneration based on the useful heat demand in the internal energy market. To fulfil the requirements of EU directives, numerous changes have been made in The Electricity Market Act. [22]

A scheme, which includes the obligation for the network operators to purchase electricity generated from renewable energy sources, has been in use since 1998. Up until May 2007, the rate of obligatory feed-in tariff was 51.77 €/MWh_{el}. For a long period of time Estonia provided a level of support in the form of feed-in tariffs, which was quite close to the range of electricity generation costs. The main idea of such a policy is to offer a moderate profit for the most cost-efficient plants [23]. This policy would work efficiently in the case of high interest to install new plants, but as a result, no new plants appeared before changes were made in the support schemes [24].

In 2007 several important changes were made in the support schemes for electricity production from renewable sources and in cogeneration production plants. Earlier, cogeneration had not been supported in Estonia, and the new provisions of the Act stimulated high efficiency cogeneration by electricity purchase obligation and certain feed-in tariff. Two alternatives were introduced as options for cogeneration: either to select a combination of purchase obligation with the feed-in tariff, or to only apply for a subsidized feed-in tariff. However, the subsidy system was changed again from 1 July 2010.

Current subsidy mechanisms which are summarized in *Table 2.1.* are included in the valid Electricity Market Act. The main difference of biomass energy subsidizing is that only the feed-in tariff is used. The purchase obligation is not any more available. Electricity produced in the cogeneration mode from biomass is subsidized by the feed-in tariff, which is given per MWh of electricity delivered to the grid. The oil shale energy sector is subsidized by the net capacity operation of oil shale plants and does not depend on the electricity production level. The evaluation of cogeneration regime of biomass CHP plants should be performed based on *Biomass based cogeneration principles* [25]. According to this document, electricity is produced in the cogeneration regime if the efficiency is at least 0.4. The determination of cogeneration in the annual total net regime on the basis of annual calculations as well as some other issues does not seem to be optimal and in the near future some changes in this document are expected (proposals from the Estonian Competition Authority are already provided for the consideration) [26].

Table 2.1 Current subsidy mechanisms for biomass and oil shale energy

Fuel	Subsidy mechanism	Subsidy description
Oil shale	If CO_2 quota price is above 20 €/tCO_2, then 16.0 €/MW_{el} per hour	The subsidy is valid for oil shale plants, which were launched between January 1, 2013 and January 1, 2016. The subsidy is valid for 20 years. The subsidy should not exceed 83.3 M€ annually.
	If CO_2 quota price is 15 – 20 €/tCO_2, then 14.7 €/MW_{el} per hour	
	If CO_2 quota price is 10 – 14.99 €/tCO_2, then 14.1 €/MW_{el} per hour	
Biomass	53.7 €/MWh_{el}	Electricity is produced in cogeneration regime. The feed-in tariff is valid for 12 years.
Other fuels	32.0 €/MWh_{el}	Electricity is produced in effective cogeneration regime. The CHP plant electrical capacity does not exceed 10 MW_{el}.[1] The feed-in tariff is valid for 12 years.

[1] - except peat, waste, oil shale gas

The evaluation of an effective cogeneration regime should be performed based on the enactment of *Requirements for effective cogeneration* [27]. If a CHP plant does not fulfil the requirements during the reporting period (1 month), the subsidy for this period will not be paid. So during CHP plant dimensioning and selection of CHP technology it is important to estimate the CHP plant operation mode for the purpose to avoid the unexpected denial of subsidy.

2.7 Measures for evaluating investments

There are different approaches to determine and calculate measures for evaluating investments. Regardless of differences it is necessary to calculate and show the project relate revenues, costs, capital structure and other components, which are necessary for an investment analysis. So it is important to provide a basic data for calculations and calculate main measures for evaluating investment. The additional, more profound analysis could be performed later, taking into account probable requirements and needs.

For the project basic evaluation the two most-used measures for evaluating an investment are used. They are the net present value and the internal rate of return which are based on cash flows. It is important to differ the project related IRR and NPV from the equity related IRR and NPV where project IRR is the cash flow return without debt. The project IRRs calculate return based on the project cash outflows and cash inflows only, irrespective the source of financing. The equity IRRs calculate the return to equity investors and therefore also consider the amount and cost of available debt financing. The decision to proceed with an investment is based on returns to the investors, so equity IRR will be more appropriate in many cases. However, there will also be cases where a project IRR may be appropriate. [28]

According to the Estonian *Income Tax Act* [29], the undistributed profits are not taxed in Estonia. The standard rate (flat) on gross dividends is 21%. It is assumed in the majority of cases of investment analysis that there are no undistributed profits, so the tax rate is zero. In the CHP modelling the same assumption is valid.

Taking into account the above mentioned assumptions and descriptions, the following formation of free cash flow on firm (FCFF) and free cash flow on equity (FCFE) for the calculation of Project IRR and Equity IRR is proposed (*Figure 2.3*).

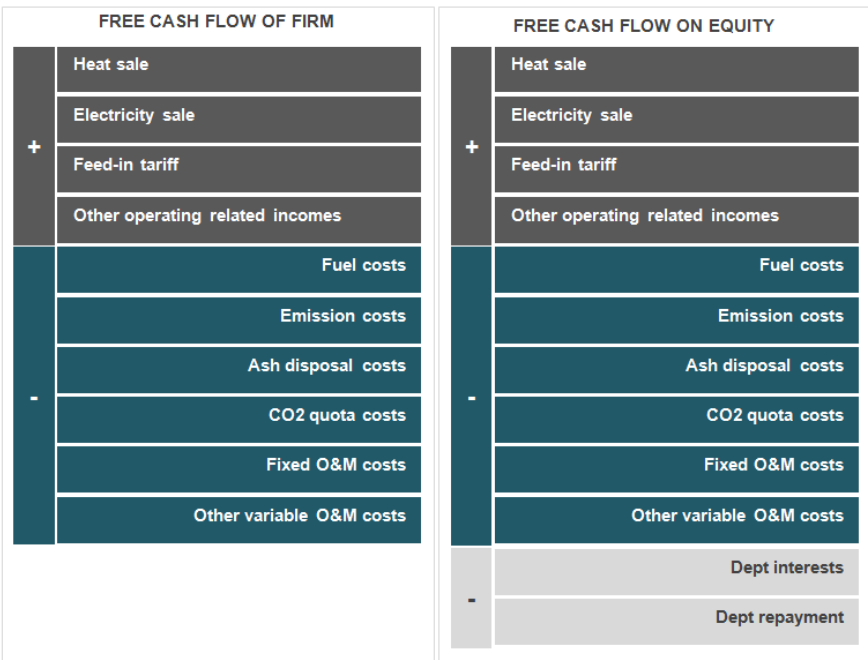


Figure 2.3 The FCFF and FCFE formation

So for no debt in the project capital structure, the FCFF and FCFE will be equal, which means that the project IRR and equity IRR will be the same.

2.8 Simplified conceptual model scheme

Summarizing the information provided in Chapters 2.1 to 2.7, the simplified conceptual model scheme is composed. The scheme is shown in *Figure 2.4*.

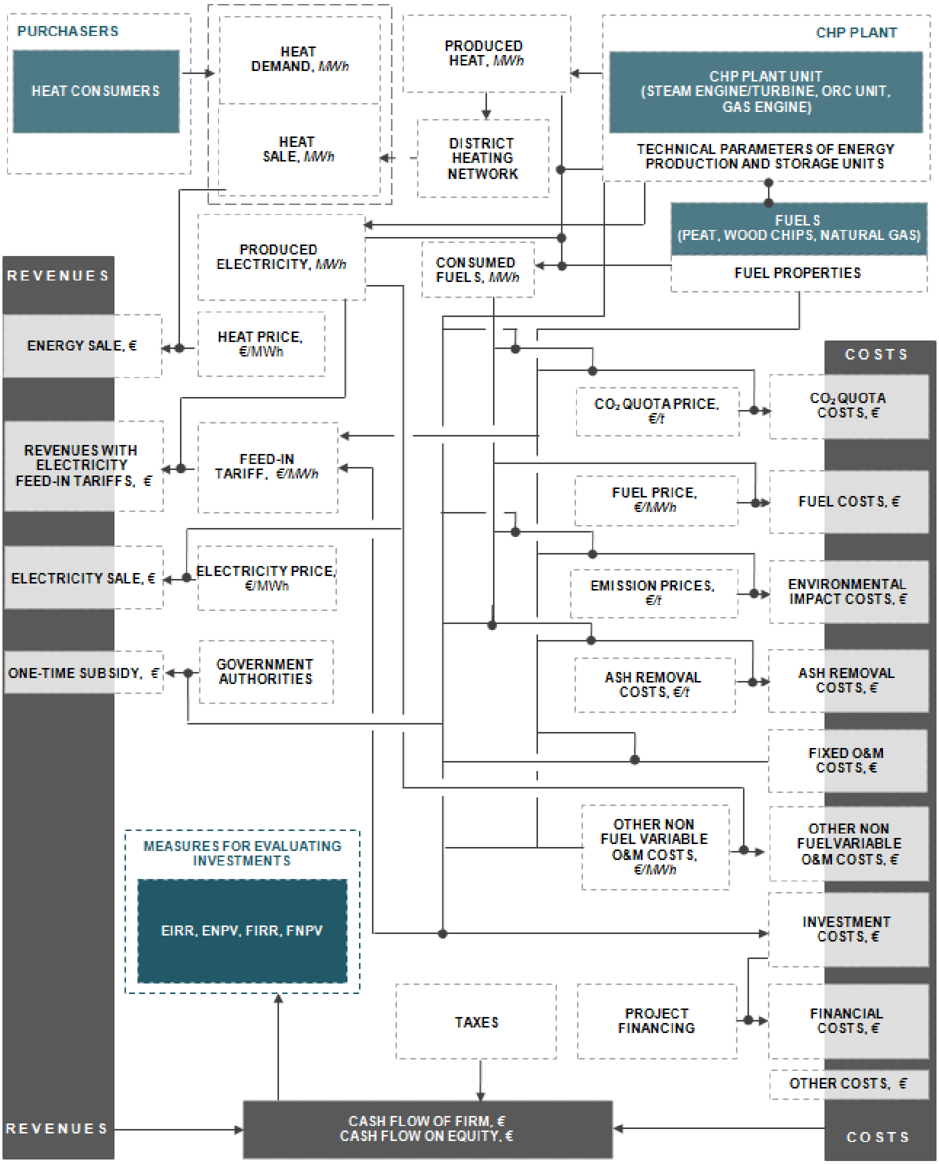


Figure 2.4 Simplified conceptual model of a CHP plant

3 MATHEMATICAL MODEL

This chapter deals with developing a mathematical model for a CHP plant based on the simplified conceptual model described in the previous chapter.

The mathematical model quantifies the state of any component as a numeric variable while the processes are described by using a series of mathematical equations [30]. The main request made to the mathematical model is to enable providing calculations at least on the pre-feasibility study level. It means that calculations have to make it possible to provide a preliminary assessment of technical and economic viability of the proposed project, estimate costs of development and operations, assess anticipated benefits and preliminary economic criteria for the evaluation.

Compared with the simplified conceptual model, the mathematical model includes data related to the project time schedule, which will affect modelling of other components. The mathematical model components/modules also have to be considered in an appropriate order, because the output of some equations could be the input for others. The composition of mathematical model will be considered in the following Chapters: 3.1 to 3.16. The order of described components is shown in *Figure 3.1*.

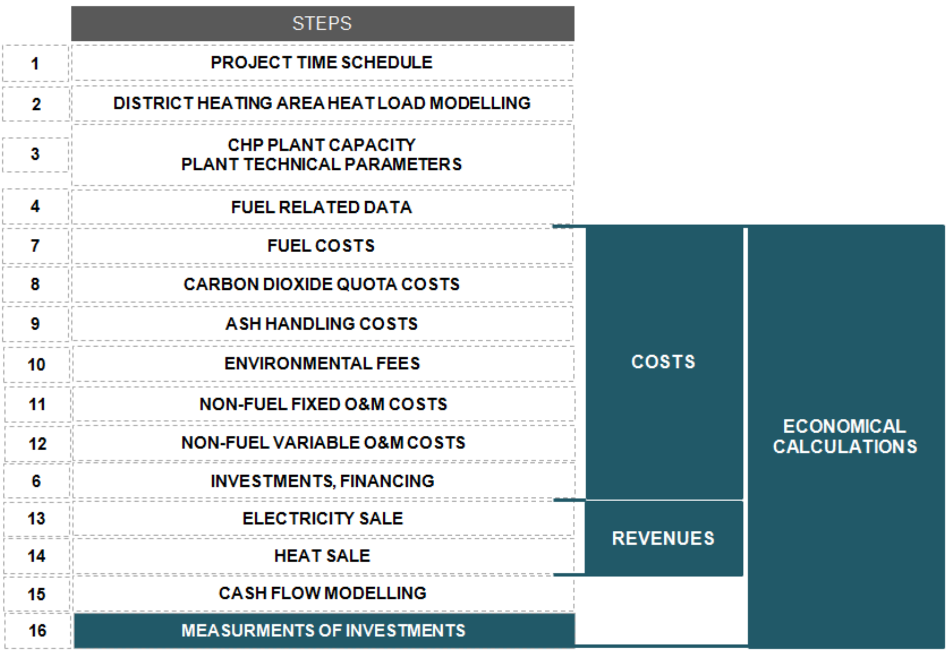


Figure 3.1 Composition of the mathematical model and order of consideration

3.1 Project time schedule

Project time schedule is important for defining the main project related dates, such as project startup, the year of operation and total length of the project.

During the time between the project start up and start of operation the following major actions are taken:

- Pre-feasibility study;
- Feasibility study;
- Pre-engineering;
- Environmental Impact Assessment;
- Engineering;
- Procurement;
- Construction;
- Consulting Services;
- Commissioning.

It is assumed that during this period all investments will be performed.

For further calculations the following project time schedule related data should be specified:

- T_{start} – project start-up (date number format "YYYY");
- T_{com} – the year of plant commercial operation (date number format "YYYY");
- T_{length} – length of the project, years.

The number of operation year states:

$$T_{op} = T_{length} - (T_{com} - T_{start}), \tag{3.1}$$

where T_{op} – length of the project commercial operation, years.

In the equations provided in the following chapters t means the year of project development where t is from 1 to T_{length}.

The values without t mean that it is the basic (first) or nonindex value.

3.2 Heat load estimation principles

For heat load simulation the data on heat demand and climate conditions are necessary.

The heat demand can be established in several ways. For the consumers connected to the district heating system where heat has been supplied for many years already and their actual heat consumption is being measured, the heat demand of previous years can be taken for the basis.

3.2.1 Heat load types

It is suggested that the district heating load consists of temperature-dependent, constant and user-defined heat loads [31]. Each type of heat load is formed by different heat load consumers (*Figure 3.2*).

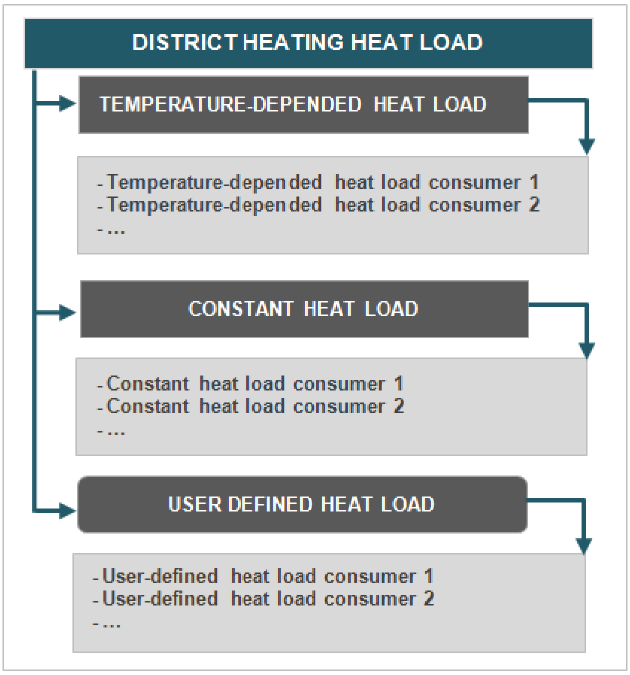


Figure 3.2 District heating heat load composition

The descriptions of temperature-dependent, constant and user defined heat loads are provided in Chapters 3.2.2 – 3.2.4.

3.2.2 Temperature-dependent heat load

The temperature-dependent heat load (TDHL) modelling procedure is the most complicated part of heat load modelling where the integration of temperature datasets is necessary. Space heating as well as ventilation with, or without heat exchangers is a good example of TDHL.

TDHL modelling is closely connected with the degree hour term [32].

A degree hour is simply the number of degrees spent above or below the standard reference temperature during 1 hour [33].

The reference year degree-hours state:

$$DH = \sum_{i=1}^{8760} (temp_{ref,n} - temp_i), \tag{3.2}$$

where DH – reference year degree-hours, $^{o}C{\cdot}h$;
$temp_i$ – reference year i hours average outdoor temperature, ^{o}C;
$temp_{ref}$ – standard reference temperature for n TDHL consumer, ^{o}C;
$n \in 1 to N$, where N is the number of TDHL consumers for the reference year.

Knowing the reference year degree-hours and TDHL n consumer annual heat consumption, its heat consumption indicator is defined as:

$$HCI_n = \frac{Q^{temp}{}_n}{DH}, \tag{3.3}$$

where $Q^{temp}{}_n$ – TDHL n consumer annual heat demand, MWh;
HCI_n – n consumer temperature-depended heat consumption indicator, MW/^{o}C.

The reference year i hours average n consumer temperature-dependent heat load states:

$$P^{temp}{}_{i,n} = HCI_n \times t_i. \tag{3.4}$$

The reference year i hours TDHL is defined as a summary of temperature-dependent consumers i hour's heat loads:

$$P^{temp}{}_i = \sum_{n=1}^{N} P^{temp}{}_{i,n}. \tag{3.5}$$

The reference year TDHL consumers' heat demand could be defined as:

$$Q^{temp} = \sum_{n=1}^{N} Q^{temp}{}_n = \sum_{i=1}^{8760} P^{temp}{}_i. \tag{3.6}$$

3.2.3 Constant heat load

The constant heat load (CHL) does not change during a year. For CHL the equality works:

$$P^{const}{}_{1,m} = P^{const}{}_{2,m} = \ldots = P^{const}{}_{8759,m} = P^{const}{}_{8760,m} = P^{const}{}_m, \tag{3.7}$$

where $P^{const}{}_m$ – CHL m consumer heat load for the reference year, MW;
$m \in 1 to M$, where M is the number of CHL consumers for the reference year.

The CHL m consumer heat load can be defined as:

$$P^{const}{}_m = \frac{Q^{const}{}_m}{8760}, \tag{3.8}$$

where $Q^{const}{}_m$ – CHL n consumer annual heat demand, MWh.
There are no examples for CHL in its pure form. But with some exceptions heat loss in district heating network as well as average daily warm water consumption could be considered as a CHL. [34]

The reference year CHL states:

$$P^{const} = \sum_{m=1}^{M} P^{const}{}_m. \tag{3.9}$$

The reference year heat demand of CHL consumers can be defined as:

$$Q^{const} = \sum_{m=1}^{M} Q^{const}{}_m = \sum_{m=1}^{M} 8760 \times P^{const}{}_m. \tag{3.10}$$

3.2.4 User-defined heat load

The user-defined heat load (UDHL) is the most flexible way to define heat loads for a CHP plant. At the same time UDHL implies that heat load is more or less defined for every hour of the reference year. The industrial heat loads are a great example of UDHL.

The UDHL demand in the reference year *i* hours can be defined as:

$$P^{user}{}_i = \sum_{l=1}^{L} P^{user}{}_{i,l}, \tag{3.11}$$

where $P^{user}{}_{i,l}$ – TDHL *l* user heat load of the reference year *i* hours, MW; $l \in 1 to L$, where *L* is the number of UDHL consumers for the reference year.

The UDHL consumers' heat demand in the reference year can be defined:

$$Q^{user} = \sum_{l=1}^{L} Q^{user}{}_l = \sum_{i=1}^{8760} P^{user}{}_i = \sum_{i=1}^{8760}\sum_{l=1}^{L} P^{user}{}_{i,l}. \tag{3.12}$$

3.2.5 District heating heat load

The district heating heat load for the reference year *i* hour is the sum of reference year *i* hour heat loads. It can be defined as:

$$P_i = P^{temp}{}_i + P^{const} + P^{user}{}_i, \tag{3.13}$$

where *Pi* – district heating heat load for the reference year *i* hour, MW.

The annual heat demand of district heating for the reference year can be defined as:

$$Q = Q^{temp} + Q^{const} + Q^{user} = \sum_{i=1}^{8760} P_i. \tag{3.14}$$

The generalized equation of district heating heat load for the reference year *i* hour states:

$$P_i = \sum_{n=1}^{N} \frac{Q^{temp}{}_n}{\sum_{i=1}^{i=8760}(t_{ref} - t_i)} \times t_i + \sum_{m=1}^{M} \frac{Q^{const}{}_m}{8760} + \sum_{l=1}^{L} P^{user}{}_{i,l}. \tag{3.15}$$

3.2.6 District heating heat load forecast

To provide a heat demand forecast all the correction factors of annual heat demand have to be defined.

The annual correction factor of heat demand $Corr^{heat.demand}{}_t$ specifies the increase or decrease of annual heat demand in comparison to the previous year percentage wise where *t* is the year of project development, where *t* is from 1 to T_{length}. Due to the fact that $Corr^{heat.demand}{}_1$ corresponds to the base year, $Corr^{heat.demand}{}_1 = 0$.

The district heating heat load for *t* year, *i* hour states:

$$P_{t,i} = \frac{Corr^{heat.demand}{}_{t}}{100} \times P_{t-1,i} + P_{t-1,i}. \tag{3.16}$$

The district heating heat demand for *t* year, *i* hour states:

$$Q_{t,i} = \frac{Corr^{heat.demand}{}_{t}}{100} \times Q_{t-1,i} + Q_{t-1,i} = \frac{Corr^{heat.demand}{}_{t}}{100} \times \\ \times \sum_{i=1}^{8760} P_{t-1,i} + \sum_{i=1}^{8760} P_{t-1,i}. \tag{3.17}$$

The generalized equation for district heating heat load for *t* year, *i* hour can be obtained by the substitution of Eq. (3.15) into Eq. (3.17) and states:

$$P_{t,i} = \left[\left(\frac{Corr^{heat.demand}{}_{t}}{100} + 1\right) \times \left(\frac{Corr^{heat.demand}{}_{t-1}}{100} + 1\right) \times \ldots \times \left(\frac{Corr^{heat.demand}{}_{1}}{100} + 1\right) \right] \times \\ \times \sum_{n=1}^{N} \frac{Q^{temp}{}_{n}}{\sum_{i=1}^{i=8760} (t_{ref} - t_i)} \times t_i + \sum_{m=1}^{M} \frac{Q^{const}{}_{m}}{8760} + \sum_{l=1}^{L} P^{user}{}_{i,l}. \tag{3.18}$$

If there are no changes in heat demand expected then $Corr^{heat.demand}{}_{t}$ = 0% and $P_{1,I} = P_{2,I} = \ldots = P_{Tlength,i}$.

3.3 CHP plant technical parameters

It is important to define such technical parameters of a CHP plant as electrical capacity, heat capacity, fuel capacity and efficiency for the nominal operation mode and that of partial operation. It is necessary to fix the minimum heat output of power plant, to eliminate the consideration of plant functioning in the technically impracticable operation mode.

The calculation principles regarding working at partial load are based on the assumption that the CHP plant parameters should be defined for the nominal, minimum and one intermediate capacity point. The use of intermediate capacity point will increase the accuracy of input of power plant partial load operation curves (capacity drop, efficiency drop etc.) provided by the manufacturers or received from other sources.

The power plant operation related data, which will be used in further calculations, is provided in *Table 3.1*. The data shown in blue cells is the initial data and should be specified.

Table 3.1. Power plant operation data

		Nominal load	Intermediate load	Minimal load
	unit	100 [%][1]	*LOADmed* [%][1]	*LOADm* [%][1]
Electrical capacity	MW_{el}	*elPnom*	*elPmed*	*elPm*
Heat capacity	MW_{heat}	*heatPnom*	*heatPmed*	*heatPm*
Fuel capacity	MW_{fuel}	*fuelPnom*	*fuelPmed*	*fuelPm*
Electrical efficiency	%	*elEFFnom*	*elEFFmed*	*elEFFm*
Heat efficiency	%	*heatEFFnom*	*heatEFFmed*	*heatEFFm*
Total efficiency	%	*totalEFFnom*	*totalEFFmed*	*totalEFFmin*

[1] - percent from the nominal electrical capacity

The descriptions of designations used in *Table 3.1*. are given as follows:
LOADm – minimum capacity point;
LOADmed – intermediate capacity point (*LOADmed is lower* than 100% and higher than *LOADm*);
elPnom – nominal electrical capacity;
elPmed – electrical capacity at intermediate point;
elPm – minimum electrical capacity;
heatPnom – nominal heat capacity;
heatPmed – electrical heat at intermediate point;
heatPm – minimum heat capacity;
fuelPnom – nominal fuel capacity;
fuelPmed – electrical fuel at intermediate point;
fuelPm – minimum fuel capacity;
elEFFnom – electrical efficiency at nominal load;
elEFFmed – electrical efficiency at intermediate load;
elEFFm – electrical efficiency at minimum load;
heatEFFnom – heat efficiency at nominal load;
heatEFFmed – heat efficiency at intermediate load;
heatEFFm – heat efficiency at minimum load;
totalEFFnom – total efficiency at nominal load;
totalEFFmed – total efficiency at intermediate load;
totalEFFmin – total efficiency at minimum load.

The calculation of non-initial data designations from *Table 3.1* is obtained as follows:

$$elPmed = \frac{elPnom \times LOADmed}{100}, \tag{3.19}$$

$$elPm = \frac{elPnom \times LOADm}{100}, \tag{3.20}$$

$$heatPnom = fuelPnom - elPnom, \tag{3.21}$$

$$heatPmed = fuelPmed - elPmed, \tag{3.22}$$

$$heatPm = fuelPm - elPm, \tag{3.23}$$

$$fuelPnom = \frac{elPnom \times 100}{elEFFnom}, \tag{3.24}$$

$$fuelPmed = \frac{elPmed \times 100}{elEFFmed}, \tag{3.25}$$

$$fuelPm = \frac{elPm \times 100}{elEFFm}, \tag{3.26}$$

$$heatEFFnom = totalEFFnom - elEFFnom, \tag{3.27}$$

$$heatEFFmed = totalEFFmed - elEFFmed, \tag{3.28}$$

$$heatEFFm = totalEFFm - elEFFm. \tag{3.29}$$

3.4 Fuel related data

The selection of feed-in tariffs and other calculation components needs information regarding the fuel state and type. They are designated as follows:
FUELren – renewable fuel;
FUELfossil – fossil fuel;
FUELgaseous – gaseous fuel;
FUELliquid – liquid fuel;
FUELsolid – solid fuel.

The following main fuel related data should be specified for enabling the following calculations:
FUELash – ash content, %;
FUELcal – fuel calorific value, MWh/t or MWh/m^3;
PRICEfuel – fuel price, €/MWh.

The following fuel related emission data should be specified:
FUELco2 – carbon dioxide emission factor, t/MWh;
FUELso2 – sulphur dioxide emission factor, t/MWh;
FUELnox – nitrogen oxides emission factor, t/MWh;
FUELco – carbon monoxide emission factor, t/MWh;
FUELpart – particulates (except for heavy metals and compounds of heavy metals) emission factor, t/MWh;
FUELvoc – volatile organic compounds emission factor, t/MWh;
FUELhm – heavy metals emission factor, t/MWh.

It is assumed that a fuel related bulk unit for the fuel calorific value, and emissions is the same.

3.5 Fuel costs

The fuel related costs ($COSTSfuel_t$) are defined as follows:

$$COSTSfuel_t = \left[(\frac{Corr^{FUELPRICE}{}_t}{100} + 1) \times (\frac{Corr^{FUELPRICE}{}_{t-1}}{100} + 1) \times ... \times (\frac{Corr^{FUELPRICE}{}_1}{100} + 1) \right] \times$$

$$\times PRICEfuel \sum_{i=1}^{8760} fuelP_{t,i}, \tag{3.30}$$

where $COSTSfuel_t$ – annual fuel cost, €;
$PRICEfuel$ – fuel price, €/MWh;
$Corr^{FUELPRICE}{}_t$ – fuel price correction factor, %.

The $PRICEfuel$ and $Corr^{FUELPRICEt}$ belongs to initial data and should be specified.

3.6 Carbon dioxide quota costs

The calculation of carbon dioxide quota cost ($COSTSquota_t$) is not provided for renewable fuels based CHP plants (if fuel type = *FUELren,* then $COSTSquota_t$ *is* 0) or units with the heat input capacity exceeding 20 MW (if $fuelPnom$ > 20 MW_{fuel}, then $COSTSquota_t$ = 0). In other cases the CO_2 quota costs are calculated as follows:

$$COSTSquota_t = \left[(\frac{Corr^{QUOTAPRICE}{}_t}{100} + 1) \cdot (\frac{Corr^{QUOTAPRICE}{}_{t-1}}{100} + 1) \cdot ... \cdot (\frac{Corr^{QUOTAPRICE}{}_1}{100} + 1) \right] \cdot$$

$$\cdot PRICEquota \cdot FUELco2 \cdot \sum_{i=1}^{8760} fuelP_{t,i} / (1000000 \cdot FUELcal), \tag{3.31}$$

where $COSTSquota_t$ – annual carbon dioxide quota costs, €;
$PRICEquota$ – CO_2 quota price, €/t;
$Corr^{QUOTAPRICE}{}_t$ – CO_2 quota price correction factor, %.

The $PRICEquota$ and $Corr^{QUOTAPRICE}{}_t$ belongs to initial data and should be specified.

3.7 Ash handling costs

The equation for calculating ash handling costs is:

$$COSTSash_t = \left[(\frac{Corr^{ASHPRICE}{}_t}{100} + 1) \times (\frac{Corr^{ASHPRICE}{}_{t-1}}{100} + 1) \times ... \times (\frac{Corr^{ASHPRICE}{}_1}{100} + 1) \right] \times$$

$$\times RATEash \times FUELash \times (\frac{DISPwet}{100} + 1) \times (\frac{DISPash}{100} + 1) / (FUELcal \times 100), \tag{3.32}$$

where $COSTSash_t$ – annual ash disposal costs, €;
$PRICEash$ – ash disposal rate, €/t;
$Corr^{ASHPRICE}{}_t$ – ash disposal price correction factor, %;
$DISPwet$ – the increase of ash weight in comparison to dry ash disposed weight, %;
$DISPash$ – the share of ash to be disposed by the ash disposal system, %.

The $PRICEash$, $Corr^{ASHPRICE}{}_t$ and $DISPwet$ belong to initial data and should be specified.

3.8 Environmental fees

The annual environmental fees consist of a sum of the costs for sulphur dioxide, nitrogen oxides, carbon oxide, volatile organic compounds, solid particles and emissions of heavy metals into the ambient air. The annual costs of carbon dioxide emissions are:

$$COSTSco2_t = \left[(\frac{Corr^{CO2RATE}{}_t}{100}+1)\times(\frac{Corr^{CO2RATE}{}_{t-1}}{100}+1)\times...\times(\frac{Corr^{CO2RATE}{}_1}{100}+1) \right]\times$$
$$\times RATEco2 \times FUELco2 \times \sum_{i=1}^{8760} fuelP_{t,i}, \qquad (3.33)$$

where $COSTSco2_t$ – annual costs of carbon dioxide emissions, €;
$Corr^{CO2RATE}{}_t$ – carbon dioxide emission charge rate correction factor, %;
$RATEco2$ – carbon dioxide emission charge rate, €/t.

The annual costs of sulphur dioxide emissions are:

$$COSTSso2_t = \left[(\frac{Corr^{SO2RATE}{}_t}{100}+1)\times(\frac{Corr^{SO2RATE}{}_{t-1}}{100}+1)\times...\times(\frac{Corr^{SO2RATE}{}_1}{100}+1) \right]\times$$
$$\times RATEso2 \times FUELso2 \times \sum_{i=1}^{8760} fuelP_{t,i}, \qquad (3.34)$$

where $COSTSso2_t$ – annual costs of sulphur dioxide emissions, €;
$Cor^{SO2RATE}{}_t$ – sulphur dioxide emission charge rate correction factor, %;
$RATEso2$ – sulphur dioxide emission charge rate, €/t.

The annual costs of nitrogen dioxide emissions are:

$$COSTSnox_t = \left[(\frac{Corr^{NOxRATE}{}_t}{100}+1)\times(\frac{Corr^{NOxRATE}{}_{t-1}}{100}+1)\times...\times(\frac{Corr^{NOxRATE}{}_1}{100}+1) \right]\times$$
$$\times RATEnox \times FUELnox \times \sum_{i=1}^{8760} fuelP_{t,i}, \qquad (3.35)$$

where $COSTSnox_t$ – annual costs of nitrogen dioxide emissions, €;
$Cor^{NOxRATE}{}_t$ – nitrogen dioxide emission charge rate correction factor, %;
$RATEnox$ – nitrogen dioxide emission charge rate, €/t.

The annual costs of carbon oxide emissions are:

$$COSTSco_t = \left[(\frac{Corr^{CORATE}{}_t}{100} + 1) \times (\frac{Corr^{CORATE}{}_{t-1}}{100} + 1) \times ... \times (\frac{Corr^{CORATE}{}_1}{100} + 1) \right] \times$$

$$\times RATEco \times FUELco \times \sum_{i=1}^{8760} fuelP_{t,i}, \tag{3.36}$$

where $COSTSco_t$ – annual costs of carbon oxide emissions, €;
$Cor^{CORATE}{}_t$ – carbon oxide emission charge rate correction factor, %;
RATEco – carbon oxide emission charge rate, €/t.

The annual costs of particulate emissions are:

$$COSTSpart_t = \left[(\frac{Corr^{PARTRATE}{}_t}{100} + 1) \times (\frac{Corr^{PARTRATE}{}_{t-1}}{100} + 1) \times ... \times (\frac{Corr^{PARTRATE}{}_1}{100} + 1) \right] \times$$

$$\times RATEpart \times FUELpart \times \sum_{i=1}^{8760} fuelP_{t,i}, \tag{3.37}$$

where $COSTSpart_t$ – annual costs of particulate emissions, €;
$Cor^{PARTRATE}{}_t$ – particulate emission charge rate correction factor, %;
RATEpart – particulate emission charge rate, €/t.

The annual costs of volatile organic compound emissions are:

$$COSTSvoc_t = \left[(\frac{Corr^{VOCRATE}{}_t}{100} + 1) \times (\frac{Corr^{VOCRATE}{}_{t-1}}{100} + 1) \times ... \times (\frac{Corr^{VOCRATE}{}_1}{100} + 1) \right] \times$$

$$\times RATEvoc \times FUELvoc \times \sum_{i=1}^{8760} fuelP_{t,i}, \tag{3.38}$$

where $COSTSvoc_t$ – annual costs of volatile organic compounds emissions, €;
$Cor^{VOCRATE}{}_t$ – volatile organic compound emission charge rate correction factor, %;
RATEvoc – volatile organic compound emission charge rate, €/t.

The annual costs on heavy metal emissions are:

$$COSTShm_t = \left[(\frac{Corr^{HMRATE}{}_t}{100} + 1) \times (\frac{Corr^{HMRATE}{}_{t-1}}{100} + 1) \times ... \times (\frac{Corr^{HMRATE}{}_1}{100} + 1) \right] \times$$

$$\times RATEhm \times FUELhm \times \sum_{i=1}^{8760} fuelP_{t,i}, \tag{3.39}$$

where $COSTShm_t$ – annual costs on heavy metal emissions, €;
$Cor^{HMRATE}{}_t$ – heavy metal emission charge rate correction factor, %;
RATEhm – heavy metal emission charge rate, €/t.

The total annual environmental costs are defined as follows:

$$COSTSenv_t = COSTSco2_t + COSTSso2_t + COSTSnox_t + COSTSco_t + \\ + COSTSpart_t + COSTSvoc_t + COSTShm_t, \tag{3.40}$$

where $COSTSenv_t$ – annual environmental costs, €.

3.9 Non-fuel fixed operation and maintenance costs

The non-fuel fixed O&M costs are defined as follows:

$$COSTSfixed\,om_t = \left[(\frac{Corr^{FIXEDOM}{}_t}{100} + 1) \times (\frac{Corr^{FIXEDOM}{}_{t-1}}{100} + 1) \times \ldots \times (\frac{Corr^{FIXEDOM}{}_1}{100} + 1) \right] \times$$
$$\times OMfixed\,, \tag{3.41}$$

where $COSTSfixedom_t$ – t year annual fixed O&M costs, €;
$OMfixed$ – base year fixed O&M costs, €;
$Corr^{FIXEDOM}{}_t$ – fixed O&M costs correction factor, %.

3.10 Non-fuel variable operation and maintenance costs

The non-fuel variable O&M costs depend on the electricity production level and are defined as follows:

$$COSTSvom_t = \left[(\frac{Corr^{VOM}{}_t}{100} + 1) \times (\frac{Corr^{VOM}{}_{t-1}}{100} + 1) \times \ldots \times (\frac{Corr^{VOM}{}_1}{100} + 1) \right] \times$$
$$\times OMv \times \sum_{i=1}^{8760} elP_{t,i}\,, \tag{3.42}$$

where $COSTSvom_t$ – i year annual variable O&M costs, €;
OMv – base year variable O&M costs, €/MWh_{el};
$Corr^{VOM}{}_t$ – variable O&M costs correction factor, %.

3.11 Investments, financing

The capital structure of investment costs may consist of equity capital, debt and subsidies. The availability of equity capital and subsidies defines the share of necessary debt. The debt calculation equation is:

$$DEBT = COSTSinv - EQUITY - SUBSIDY\,, \tag{3.43}$$

where $COSTSinv$ – project investment costs, €;
$EQUITY$ – equity capital, €;
$SUBSIDY$ – one-time investment subsidy, €;
$DEBT$ – sum of debt, €.

Annual debt repayments are:

$$PAYMENTan = \frac{DEBT \times \frac{DEBTrate}{100}}{1 - (1 + \frac{DEBTrate}{100})^{(-DEBTrep)}}\,, \tag{3.44}$$

where $PAYMENTan$ – annual annuity repayment, €;
$DEBTrate$ – interest rate, %;
$DEBTrep$ – repayment period, years.

The annual interest repayments are calculated as follows:

$$DEBTin_t = (DEBT - DEBTloanpart_{t-1} \ldots - \ldots - DEBTloanpart_1) \times \\ \times \frac{DEBTrate}{100}, \tag{3.45}$$

where $DEBTin_t$ – annual interest repayment, €;
$DEBTloanpart_t$ – annual loan part repayment, €.

The annual debt repayments are calculated as:

$$DEBTloanpart_t = PAYMENTan - inDEBT_t. \tag{3.46}$$

It is assumed, that repayments start in the first operation year and repayment period cannot exceed the period of commercial operation for all debt related calculations.

3.12 Electricity sale

3.12.1 Electricity sale related income

The electricity sale related income is defined as:

$$REVel_t = \left[(\frac{Corr^{ELPRICE}{}_t}{100} + 1) \times (\frac{Corr^{ELPRICE}{}_{t-1}}{100} + 1) \times \ldots \times (\frac{Corr^{ELPRICE}{}_1}{100} + 1) \right] \times \\ \times PRICEel \times \sum_{i=1}^{8760} elP_{t,i} \tag{3.47}$$

where $PRICEel$ – electricity price, €/MWh;
$REVel_t$ – annual revenues from electricity sale, €;
$Corr^{ELPRICE}{}_t$ – electricity price correction factor, %.

3.12.2 Feed-in tariffs related income

The feed-in tariffs are calculated for 12 years from launching the plant commercial operation. The efficiency control is provided for each month. If the total plant efficiency is lower than the appropriate total minimum efficiency level, the income with feed-in tariffs is zero for this period. To simplify the accounting on monthly basis, it is assumed that every accounting period from 12 is equal to 730 hours (12 x 730 = 8760 hours).

An algorithm for determining the feed-in tariffs is summarized in the following steps:

1. If fuel is *FUELren* and not *FUELsolid*, then $FEED = FEED1$ and $EV = EV3$ then go to step 5. Otherwise, go to step 2.
2. If fuel is *FUELren* and *FUELsolid*, then $FEED = FEED1$ and $EV = EV2$ then go to step 5. Otherwise, go to step 3.
3. If fuel is *FUELfossil* and peat, shale oil gas or waste, then $FEED = FEED2$ and $EV = EV3$ then go to step 5. Otherwise, go to step 4.
4. If fuel is *FUELfossil* and not peat, shale oil gas or waste and plant $elPnom <$ $20MW_{el}$, then $FEED = FEED2$ and $EV = EV3$, then go to step 5. Otherwise, $feedREV_t = 0$.
5. For z = 1 to 12, if $EV < \sum_{v=1}^{730} \frac{elP_{t,(z-1)\cdot 730+v} + heatP_{t,(z-1)\cdot 730+v}}{fuelP_{t,(z-1)\cdot 730+v}}$, then calculate

   $REVfeed_{t,z} = FEED \times \sum_{v=1}^{730} elP_{t,(z-1)\cdot 730+v}$, else $REVfeed_{t,z} = 0$. Go to step 6.
6. Calculate $feedREV_t = \sum_{z=1}^{12} feedREV_{t,z}$, (3.49)

where *FEED* – available feed-in tariff, €/MWh;
$FEED1 = 53.7$, €/MWh;
$FEED2 = 32.0$, €/MWh;
EV – total minimum efficiency level;
$EV1 = 0.75$;
$EV2 = 0.5$;
$EV3 = 0$;
$REVfeed_t$ – annual revenues from feed-in tariffs, €.

3.13 Heat sale

The heat sale related income is defined as:

$$REVheat_t = \left[(\frac{Corr^{HEATPRICE}{}_t}{100}+1)\times(\frac{Corr^{HEATPRICE}{}_{t-1}}{100}+1)\times\ldots\times(\frac{Corr^{HEATPRICE}{}_1}{100}+1) \right]\times$$

$$\times PRICEheat \times \frac{(100-HEATloss)}{100} \times \sum_{i=1}^{8760} heatP_{t,i}, \tag{3.50}$$

where *PRICEheat* – heat price, €/MWh;
$REVheat_t$ – annual revenues from heat sale, €;
HEATloss – heat loss in district heating network, %;
$Corr^{HEATPRICE}{}_t$ – electricity price correction factor, %.

3.14 Cash flow modelling

The free cash flow of the firm is defined as:

$$FCFF_t = REVel_t + REVheat_t + REVheat_t + REVother_t - (COSTSfuel_t +$$

$$+ COSTSenv_t + COSTSquota_t + COSTSash_t + COSTSfixedom_t +$$
$$+ COSTSvom_t) - COSTSinv, \quad (3.51)$$

where $FCFF_t$ – free cash flow of the firm, €.

The free cash flow of the equity is calculated as:

$$FCFE_t = REVel_t + REVfeed_t + REVheat_t + REVother_t - (COSTSfuel_t +$$
$$+ COSTSenv_t + COSTSquota_t + COSTSash_t + COSTSfixedom_t +$$
$$+ COSTSvom_t) - DEDBTloanpart_t - DEBTin_t, \quad (3.52)$$

where $FCFE_t$ – free cash flow of the equity, €.

3.15 Measurements of investments

The project related NPV is calculated as:

$$pNPV = -COSTSinv + \sum_{t=1}^{Tlength} \frac{FCFF_t}{(1 + \frac{pexIRR}{100})^t}, \quad (3.53)$$

where $pexIRR$ – expected project related IRR, %;
$pNPV$ – project related NPV, €.

The equity related NPV is calculated as:

$$eNPV = -EQUITY + \sum_{t=1}^{Tlength} \frac{FCFE_t}{(1 + \frac{eexIRR}{100})^t}, \quad (3.54)$$

where $eexIRR$ – expected equity related IRR, %;
$eNPV$ – equity related NPV, €.

The equity IRR and project IRR should be calculated based on Eq.(3.53) and Eq.(3.54) using trial and error method with taking into account that the equity IRR and project IRR is the rate at which the $eNPV$ and $pNPV$ equals 0.

3.16 Primary energy efficiency

The primary energy efficiency (PEE) is a ratio of final energy consumption to the used primary energy from the energy source. The calculation of PEE is important to indicate the energy performance and consequently the quality of energy systems.

Primary energy (PE) is the energy that has not been subject to any conversion or transformation process. The use of primary energy factors takes into account the energy that is used from the extraction of the energy carrier and all the losses until the energy is delivered to the end user in the desired form such as heat, cooling or electricity.

The primary energy factor (PEF) expresses how much primary energy is needed to deliver 1 unit of power, heat or cooling to the end user. Therefore the term primary energy efficiency (PEE) is used to describe the total use of energy from the extraction to the supply to end user where also the system efficiency within the buildings is included.

The use of the primary energy concept and CO_2 emission accounting is recommended when implementing Directive 2002/91/EC on the energy performance of buildings and the recast of the same directive (2010/31/EU) with a clear reference also to Directive 2009/28/EC on the promotion of the use of energy from renewable sources. For implementation it is also referred to some European standards, such as EN 15603:2007 and EN 15217:2007.

The development of PEE estimation methods is closely connected to the estimation of accurate PEF values. It is important to find an optimum between the simplicity of general values, which will not remain valid for many specific cases and complicate life cycle assessment like methods, which imply the collection of thousands of parameters. It is necessary to work on developing systems, methods and to collect credible data regarding the energy chains for calculating the actual values of PEF.

A CHP plant is only one part of an energy chain, which mainly includes fuel extraction, processing, storage, transport, transformation, and transmission and distribution [49]. The estimation of primary energy use in CHP plants is an important step in the PEF defining process. In this study the estimation of primary energy savings by CHP plant is provided based on the enactment of *Efficient Co-generation Requirements* [47, 48].

The primary energy savings during the CHP production are:

$$PES = \left(1 - \frac{1}{\dfrac{CHPH\,\eta}{REFH\,\eta} + \dfrac{CHPE\,\eta}{REFH\,\eta}} \right) \times 100\,\%, \tag{3.55}$$

where PES – primary energy saving;
$CHPH\eta$ – useful heat efficiency of CHP plant;
$REFH\eta$ – indicative efficiency of separate heat production;
$CHPE\eta$ – electrical efficiency of CHP plant;
$REFE\eta$ – indicative efficiency of separate electricity production.

The useful electrical efficiency of CHP plant in the base year:

$$CHPE\eta = \frac{\sum_{i=1}^{8760} elP_{1,i}}{\sum_{i=1}^{8760} fuelP_{1,i}}. \tag{3.56}$$

The useful heat efficiency of CHP plant in the base year is:

$$CHPH\eta = \frac{\sum_{i=1}^{8760} heatP_{1,i}}{\sum_{i=1}^{8760} fuelP_{1,i}}. \tag{3.57}$$

According to [47], the indicative efficiency of separate heat production is 86% for peat and woodchips and 90% for natural gas.

The indicative efficiency of separate electricity production is 39% for peat, 34% for woodchips and 52.5% for natural gas.

As an example, a woodchip based CHP plant with the useful heat efficiency of 65% and electrical efficiency of 20% will allow saving 26% of PE in comparison with the separate production of the same amount of heat and electricity.

3.17 Initial data

To provide the calculation steps described in Chapters 3.1 to 3.17 the following initial data should be specified:

1. T_{start} – project start-up (date number format "YYYY");
2. T_{com} – the year of plant's commercial operation (date number format "YYYY");
3. T_{length} – length of the project, years;
4. $temp_i$ – average outdoor temperature of the reference year *i* hours, ^{o}C;
5. $temp_{ref}$ – standard reference temperature for *n* TDHL consumer, ^{o}C;
6. Q^{temp}_{n} – TDHL *n* consumer annual heat demand, MWh;
7. P^{const}_{m} – CHL *m* consumer heat load for reference year, MW;
8. Q^{const}_{m} – CHL *n* consumer annual heat demand, MWh;
9. $P^{user}_{i,l}$ – TDHL *l* user heat load in the reference year *i* hours, MW;
10. $Corr^{heat.demand}_{t}$ – annual heat demand correction factor, %;
11. *LOADm* – minimum capacity point;
12. *LOADmed* – intermediate capacity point (*LOADmed* is lower than 100% and higher than *LOADm*);
13. *elPnom* – nominal electrical capacity;
14. *elEFFnom* – electrical efficiency at nominal load;
15. *elEFFmed* – electrical efficiency at intermediate load;
16. *elEFFm* – electrical efficiency at minimum load;
17. *totalEFFnom* – total efficiency at nominal load;
18. *totalEFFmed* – total efficiency at intermediate load;
19. *totalEFFmin* – total efficiency at minimum load;
20. *FUELash* – ash content, %;
21. *FUELcal* – fuel calorific value, MWh/t or MWh/m^3;
22. *PRICEfuel* – fuel price, €/MWh_{fuel};
23. *FUELco2* – carbon dioxide emission, t/MWh_{fuel};

24. *FUELso2* – sulphur dioxide emission, t/MWh$_{fuel}$;
25. *FUELnox* – nitrogen oxides emission, t/MWh$_{fuel}$;
26. *FUELco* – carbon monoxide emission, t/MWh$_{fuel}$;
27. *FUELpart* – particulates (except for heavy metals and compounds of heavy metals), t/MWh;
28. *FUELvoc* – volatile organic compounds (except for mercaptans) emission, t/MWh$_{fuel}$;
29. *FUELhm* – heavy metals emission, t/MWh$_{fuel}$;
30. Fuel type/state:
- *FUELren* – renewable fuel;
- *FUELfossil* – fossil fuel;
- *FUELgaseous* – gaseous fuel;
- *FUELliquid* – liquid fuel;
- *FUELsolid* – solid fuel.
31. *COSTSinv* – project investment costs, €;
32. *EQUITY* – equity capital, €;
33. *SUBSIDY* – one-time investment subsidy, €;
34. $Corr^{FUELPRICE}_t$ – fuel price annual correction factor, %;
35. *PRICEquota* – CO_2 quota price, €/t;
36. $Corr^{QUOTAPRICE}_t$ – CO_2 quota price correction factor, %;
37. *PRICEash* – ash disposal rate, €/t;
38. $Corr^{ASHPRICE}_t$ – ash disposal price correction factor, %;
39. *DISPwet* – the increase of ash weight in comparison to dry ash disposed weight, %;
40. *DISPash* – the share of ash to be disposed by the ash disposal system, %;
41. $Corr^{CO2RATE}_t$ – carbon dioxide emission charge rate correction factor, %;
42. *RATEco2* – carbon dioxide emission charge rate, €/t;
43. $Cor^{SO2RATE}_t$ – sulphur dioxide emission charge rate correction factor, %;
44. *RATEso2* – sulphur dioxide emission charge rate, €/t;
45. $Cor^{NOxRATE}_t$ – nitrogen dioxides emission charge rate correction factor, %;
46. *RATEnox* – nitrogen dioxides emission charge rate, €/t;
47. Cor^{CORATE}_t – carbon oxide emission charge rate correction factor, %;
48. *RATEco* – carbon oxide emission charge rate, €/t;
49. $Cor^{PARTRATE}_t$ – particulates emission charge rate correction factor, %;
50. *RATEpart* – particulates emission charge rate, €/t;
51. $Cor^{VOCRATE}_t$ – volatile organic compounds emission charge rate correction factor, %;
52. *RATEvoc* – volatile organic compounds emission charge rate, €/t;
53. Cor^{HMRATE}_t – heavy metals emission charge rate correction factor, %;
54. *RATEhm* – heavy metals emission charge rate, €/t;
55. *OMfixed* – base year fixed O&M costs, €;
56. $Corr^{FIXEDOM}_t$ – fixed O&M costs correction factor, %;
57. *OMv* – base year variable O&M costs, €/MWh$_{el}$;
58. $Corr^{VOM}_t$ – variable O&M costs correction factor, %;
59. *COSTSinv* – project investment costs, €;

60. *EQUITY* – equity capital, €;
61. *SUBSIDY* – one-time investment subsidy, €;
62. *DEBTrate* – interest rate, %;
63. *DEBTrep* – repayment period, years;
64. *PRICEel* – electricity price, €/MWh_{el};
65. $Corr^{ELPRICE}{}_{t}$ – electricity price correction factor, %;
66. *PRICEheat* – heat price, €/MWh_{heat};
67. *HEATloss* – heat loss in district heating network, %;
68. $Corr^{HEATPRICE}{}_{t}$ – electricity price correction factor, %;
69. *pexIRR* – expected project related IRR, %;
70. *eexIRR* – expected equity related IRR, %.

For the calculation of case-specific project on the feasibility level (the pre-feasibility study is prepared, budgetary inquiries for the plant equipment are received, CHP technology is selected, technology related data is estimated, fuel and fuel properties are identified, investment related issues are considered, etc.) the manual selection of above mentioned initial data could be reasonable.

To simplify the calculations in the pre-feasibility stage or provide not case-specific calculations the use of pre-defined generalized data can be more preferable. The use of internal databases concerning technologies, fuels, emissions will decrease the amount of initial data.

It is important that the information used in databases and data selection principles are clear and acceptable by the user.

The use of databases will allow decreasing the amount of initial data from 70 components/values to maximum 7 where the following components/values should be identified:

1. LOC_i – CHP plant location;
2. *elPnom* – nominal electrical capacity;
3. *tec* – CHP plant technology;
4. *fuel* – used fuel;
5. $Q^{temp}{}_{n}$;
6. $P^{const}{}_{m}$ or $Q^{const}{}_{m}$;
7. $P^{user}{}_{i,l}$.

If the data on the heat demand of district heating area is available, the calculations come to defining 4 characteristics:

1. *elPnom* – nominal electrical capacity;
2. *tec* – CHP plant technology;
3. *fuel* – used fuel;
4. $P^{user}{}_{i,l}$.

The selection of initial data for the CHP plant calculations with the use of databases and pre-defined values is described below.

3.17.1 Technologies related initial data

Technologies related initial data is provided for six fixed reference capacities (0.1, 0.5, 1, 5, 10 and 50 MW). The distribution of capacity data will allow taking into account the influence of CHP plant scale-factor data values. The technologies related data is shown in *Table 3.2*.

Table 3.2. CHP technologies related data

	Reference capacity	Efficiency		Partial load performance		Specific investment	O&M costs	
		Electrical	total	min. capacity	el. efficiency at min. capacity		Fixed O&M	Variable O&M
	MW_{el}	%	%	%	%	$M€/MW_{el}$	% from the investments	$€/MWh_{el}$
Steam engine	0.1	9	85	20	90	9.0	2.5	2.6
	0.5	12	85	20	90	7.0	2.5	2.2
	1	14	85	20	90	5.0	2.5	1.9
	5	14	85	20	90	3.8	2.5	1.9
	10	14	85	20	99	3.8	2.5	1.9
	50	14	85	20	99	3.8	2.5	1.9
Steam turbine	0.1	9	85	30	35	9.0	2.5	2.2
	0.5	12	85	30	35	7.7	2.5	2.2
	1	16	85	30	35	5.0	2.5	1.9
	5	20	85	30	35	4.0	2.5	1.6
	10	25	85	30	35	3.3	2.5	1.3
	50	32	85	30	35	2.2	2.5	1.3
Gas engine	0.1	30	85	25	85	1.3	2.5	3.2
	0.5	32	85	25	85	1.2	2.5	2.9
	1	36	85	25	85	0.8	2.5	2.6
	5	39	85	25	85	0.7	2.5	2.2
	10	40	85	25	85	0.7	2.5	1.9
	50	40	85	25	95	0.6	2.5	1.9
ORC unit	0.1	13	85	20	90	7.0	2	1.9
	0.5	14	85	20	90	5.8	2	1.6
	1	15	85	20	90	4.5	2	1.3
	5	16	85	20	90	3.5	2	1.3
	10	16	85	20	98	2.9	2	1.3
	50	16	85	20	99	2.9	2	1.3

The values proposed in *Table 3.2* are obtained and systemized on the basis of information about CHP plants collected from different information sources such as [35, 36, 37, 38 and 39].

The designations shown in *Table 3.3* are used to describe the principles of initial data selection from the values shown in *Table 3.2*.

Table 3.3. CHP technologies related data designations

tec	Reference capacity	Efficiency		Partial load performance		Specific investment	O&M costs	
		electrical	total	min. capacity	el. efficiency at min. capacity		Fixed O&M	Variable O&M
	MW_{el}	%	%	%	%	€/MW_{el}	% from the invest-ments	€/MWh_{el}
1	rc_1	$ELEFF_{1,1}$	$TEFF_{1,1}$	$mCAPP_{1,1}$	$ELEFFdrop_{1,1}$	$SPECINV_{1,1}$	$FOM_{1,1}$	$VOM_{1,1}$
	rc_2	$ELEFF_{1,2}$	$TEFF_{1,2}$	$mCAPP_{1,2}$	$ELEFFdrop_{1,2}$	$SPECINV_{1,2}$	$FOM_{1,2}$	$VOM_{1,2}$
	rc_3	$ELEFF_{1,3}$	$TEFF_{1,3}$	$mCAPP_{1,3}$	$ELEFFdrop_{1,3}$	$SPECINV_{1,3}$	$FOM_{1,3}$	$VOM_{1,3}$
	rc_4	$ELEFF_{1,4}$	$TEFF_{1,4}$	$mCAPP_{1,4}$	$ELEFFdrop_{1,4}$	$SPECINV_{1,4}$	$FOM_{1,4}$	$VOM_{1,4}$
	rc_5	$ELEFF_{1,5}$	$TEFF_{1,5}$	$mCAPP_{1,5}$	$ELEFFdrop_{1,5}$	$SPECINV_{1,5}$	$FOM_{1,5}$	$VOM_{1,5}$
	rc_6	$ELEFF_{1,6}$	$TEFF_{1,6}$	$mCAPP_{1,6}$	$ELEFFdrop_{1,6}$	$SPECINV_{1,6}$	$FOM_{1,6}$	$VOM_{1,6}$
2	rc_1	$ELEFF_{2,1}$	$TEFF_{2,1}$	$mCAPP_{2,1}$	$ELEFFdrop_{2,1}$	$SPECINV_{2,1}$	$FOM_{2,1}$	$VOM_{2,1}$
	rc_2	$ELEFF_{2,2}$	$TEFF_{2,2}$	$mCAPP_{2,2}$	$ELEFFdrop_{2,2}$	$SPECINV_{2,2}$	$FOM_{2,2}$	$VOM_{2,2}$
	rc_3	$ELEFF_{2,3}$	$TEFF_{2,3}$	$mCAPP_{2,3}$	$ELEFFdrop_{2,3}$	$SPECINV_{2,3}$	$FOM_{2,3}$	$VOM_{2,3}$
	rc_4	$ELEFF_{2,4}$	$TEFF_{2,4}$	$mCAPP_{2,4}$	$ELEFFdrop_{2,4}$	$SPECINV_{2,4}$	$FOM_{2,4}$	$VOM_{2,4}$
	rc_5	$ELEFF_{2,5}$	$TEFF_{2,5}$	$mCAPP_{2,5}$	$ELEFFdrop_{2,5}$	$SPECINV_{2,5}$	$FOM_{2,5}$	$VOM_{2,5}$
	rc_6	$ELEFF_{2,6}$	$TEFF_{2,6}$	$mCAPP_{2,6}$	$ELEFFdrop_{2,6}$	$SPECINV_{2,6}$	$FOM_{2,6}$	$VOM_{2,6}$
3	rc_1	$ELEFF_{3,1}$	$TEFF_{3,1}$	$mCAPP_{3,1}$	$ELEFFdrop_{3,1}$	$SPECINV_{3,1}$	$FOM_{3,1}$	$VOM_{3,1}$
	rc_2	$ELEFF_{3,2}$	$TEFF_{3,2}$	$mCAPP_{3,2}$	$ELEFFdrop_{3,2}$	$SPECINV_{3,2}$	$FOM_{3,2}$	$VOM_{3,2}$
	rc_3	$ELEFF_{3,3}$	$TEFF_{3,3}$	$mCAPP_{3,3}$	$ELEFFdrop_{3,3}$	$SPECINV_{3,3}$	$FOM_{3,3}$	$VOM_{3,3}$
	rc_4	$ELEFF_{3,4}$	$TEFF_{3,4}$	$mCAPP_{3,4}$	$ELEFFdrop_{3,4}$	$SPECINV_{3,4}$	$FOM_{3,4}$	$VOM_{3,4}$
	rc_5	$ELEFF_{3,5}$	$TEFF_{3,5}$	$mCAPP_{3,5}$	$ELEFFdrop_{3,5}$	$SPECINV_{3,5}$	$FOM_{3,5}$	$VOM_{3,5}$
	rc_6	$ELEFF_{3,6}$	$TEFF_{3,6}$	$mCAPP_{3,6}$	$ELEFFdrop_{3,6}$	$SPECINV_{3,6}$	$FOM_{3,6}$	$VOM_{3,6}$
4	rc_1	$ELEFF_{4,1}$	$TEFF_{4,1}$	$mCAPP_{4,1}$	$ELEFFdrop_{4,1}$	$SPECINV_{4,1}$	$FOM_{4,1}$	$VOM_{4,1}$
	rc_2	$ELEFF_{4,2}$	$TEFF_{4,2}$	$mCAPP_{4,2}$	$ELEFFdrop_{4,2}$	$SPECINV_{4,2}$	$FOM_{4,2}$	$VOM_{4,2}$
	rc_3	$ELEFF_{4,3}$	$TEFF_{4,3}$	$mCAPP_{4,3}$	$ELEFFdrop_{4,3}$	$SPECINV_{4,3}$	$FOM_{4,3}$	$VOM_{4,3}$
	rc_4	$ELEFF_{4,4}$	$TEFF_{4,4}$	$mCAPP_{4,4}$	$ELEFFdrop_{4,4}$	$SPECINV_{4,4}$	$FOM_{4,4}$	$VOM_{4,4}$
	rc_5	$ELEFF_{4,5}$	$TEFF_{4,5}$	$mCAPP_{4,5}$	$ELEFFdrop_{4,5}$	$SPECINV_{4,5}$	$FOM_{4,5}$	$VOM_{4,5}$
	rc_6	$ELEFF_{4,6}$	$TEFF_{4,6}$	$mCAPP_{4,6}$	$ELEFFdrop_{4,6}$	$SPECINV_{4,6}$	$FOM_{4,6}$	$VOM_{4,6}$

Depending on the chosen pre-defined technology (*tec*) and specified power plant nominal electrical capacity (*elPnom*), the following initial data selection steps are used:

1). If $elPnom < rc_1$ or $elPnom > rc_6$, then $rc_{i-1} = ELEFF_{tec,i-1} = TEFF_{tec,i-1} = mCAPP_{tec,i-1} = ELEFFdrop_{tec,i-1} = SPECINV_{tec,i-1} = FOM_{tec,i-1} = VOM_{tec,i-1} = 0$ and go to step 3. Else, go to step 2.

2). For i=2 to 6. If $rc(i-1) \le elPnom < rc_i$, then go to step 3, else next i.

3)

$$LOADm = \frac{mCAPP_{tec,i} - mCAPP_{tec,i-1}}{rc_i - rc_{i-1}} \times elPnom + mCAPP_{tec,i-1}, \tag{3.58}$$

$$LOADmed = \frac{100 + LOADm}{2}, \tag{3.59}$$

$$elEFFnom = \frac{ELEFF_{tec,i} - ELEFF_{tec,i-1}}{rc_i - rc_{i-1}} \times elPnom + ELEFF_{tec,i-1}, \tag{3.60}$$

$$elEFFm = \frac{ELEFFnom}{100} \times (\frac{ELEFFdrop_{tec,i} - ELEFFdrop_{tec,i-1}}{rc_i - rc_{i-1}} \times elPnom + ELEFFdrop_{tec,i-1}), \tag{3.61}$$

$$elEFFmed = \frac{elEFFnom + elEFF\min}{2}, \tag{3.62}$$

$$totalEFFnom = totalEFFmed = totalEFFm = \frac{TEFF_{tec,i} - TEFF_{tec,i-1}}{rc_i - rc_{i-1}} \times elPnom + TEFF_{tec,i-1}, \tag{3.63}$$

$$COSTSinv = elPnom \times \frac{SPECINV_{tec,i} - SPECINV_{tec,i-1}}{rc_i - rc_{i-1}} \times elPnom + SPECINV_{tec,i-1}, \tag{3.64}$$

$$OMv = \frac{VOM_{tec,i} - VOM_{tec,i-1}}{rc_i - rc_{i-1}} \times elPnom + VOM_{tec,i-1}, \tag{3.65}$$

$$OMfixed = \frac{COSTSinv}{100} \times (\frac{FOM_{tec,i} - FOM_{tec,i-1}}{rc_i - rc_{i-1}} \times elPnom + FOM_{tec,i-1}). \tag{3.66}$$

3.17.2 Fuel related initial data

The fuel database consists of woodchips, peat and natural gas related data, which is shown in *Table 3.4*.

Table 3.4. Fuel related data

	Woodchips	Peat	Natural gas
Fuel type/state	$Fuel^{solid}$, $Fuel^{ren}$	$Fuel^{solid}$, $Fuel^{fossil}$	$Fuel^{gaseos}$, $Fuel^{fossil}$
Calorific value, MWh/t (MWh/m^3 for natural gas)	2.4	3.3	0.0093
Ash content, %	1	5	0
Fuel price, €/MWh	12.8	11.7	28
Emission factors, t/MWh			
Carbon dioxide, CO_2	0	0.374	0.201
Sulphur dioxide, SO_2	0	0.00072	0
Nitrogen oxides, NO_x	0.00036	0.0011	0.00022
Carbon monoxide, CO	0.00072	0.00036	0.00014
Particulates	0.00025	0.00029	0
Volatile organic compounds	0.00017	0.00036	0.000014
Heavy metals	0.000000104	0.00000028	0

Table 3.5. shows the designations for the data provided in *Table 3.4*. The values for emission factors are determined on the basis of calculations regarding [14]. This method takes into account different combustion technologies, flue gas cleaning technologies, control devices as well as capacities to define the emission factors of pollutants.

To avoid the complexity of analysis arising from different combinations of capacities, combustion technologies, fuel gas cleaning and control equipment, it is assumed that:

- the thermal capacity of combustion plants is below 50 MW;
- the selected combustion technology provides the lowest emission level compared to all other combustion technologies mentioned in [14];
- the combustion plant is equipped with the most effective control systems mentioned in [14];
- the combustion plant is equipped with the most effective flue gas treatment technology mentioned in [14].

The emissions of carbon dioxide are calculated according to the method described in [15], thereby the carbon dioxide emissions from biofuels equal zero.

Table 3.5. Fuel related data designation

	fuel=1	fuel=2	fuel=3
Fuel type/state	$Fuel^{solid}$, $Fuel^{ren}$	$Fuel^{solid}$, $Fuel^{fossil}$	$Fuel^{gaseos}$, $Fuel^{fossil}$
Calorific value, MWh/t (MWh/m^3 for natural gas)	$CALV_1$	$CALV_2$	$CALV_3$
Ash content, %	ASH_1	ASH_2	ASH_2
Fuel price, €/MWh	$FPRICE_1$	$FPRICE_2$	$FPRICE_3$
Emission factors, t/MWh			
Carbon dioxide, CO_2	$PRICECO2_1$	$PRICECO2_2$	$PRICECO2_3$
Sulphur dioxide, SO_2	$PRICESO2_1$	$PRICESO2_2$	$PRICESO2_3$
Nitrogen oxides, NO_x	$PRICENOx_1$	$PRICENOx_2$	$PRICENOx_3$
Carbon monoxide, CO	$PRICECO_1$	$PRICECO_2$	$PRICECO_3$
Particulates	$PRICEPT_1$	$PRICEPT_2$	$PRICEPT_3$
Volatile organic compounds	$PRICEVOC_1$	$PRICEVOC_2$	$PRICEVOC_3$
Heavy metals	$PRICEHM_1$	$PRICEHM_2$	$PRICEHM_3$

Depending on the chosen pre-defined fuel (*fuel*), the fuel related initial data is specified as follows:
Fuel=i, where $i \in 1 to 3$;
$FUELash = ASH_i$;
$FUELcal = CALV_i$;
$PRICEfuel = FPRICE_i$;
$FUELco2 = PRICECO2_i$;
$FUELso2 = PRICESO2_i$;
$FUELnox = PRICENOx_i$;
$FUELco = PRICECO_i$;
$FUELpart = PRICEPT_i$;
$FUELvoc = PRICEVOC_i$;
$FUELhm = PRICEHM_i$.

3.17.3 Location related initial data

Modelling of temperature dependent heat load is connected with the integration of temperature datasets. The availability of this data is necessary and it has to be a part of the location related database. For the time being the temperature data is available for the cities of Tallinn, Jõhvi, Jõgeva, Pärnu, Tõravere, Vilsandi and Võru. This data is obtained from the Estonian Meteorological and Hydrological Institute. The selection of an appropriate location will set the average outdoor temperature of *i* hours ($temp_i$).

3.17.4 Financing related initial data

It is assumed that the debt to equity ratio is 3:7. This ratio was preferred during the preparation of some energy sector related pre-feasibility studies in 2010. The one-time subsidies are not taken into account (*SUBSIDY*=0). Therefore the equity capital and debt are:

$$EQUITY = COSTSinv \times 0.3; \tag{3.67}$$

$$DEBT = COSTSinv \times 0.7. \tag{3.68}$$

Interest rate (*DEBTrate*) is equal to the weighted average annual interest rates of € denominated over 10 years loans for commercial undertakings and regarding to statistics provided by the Bank of Estonia is 4% [40]. By default the repayment period is equal to the power plant operation period ($DEBTrep=T_{op}$). The selection principle of power plant operation period is described in Chapter 3.17.7. Proposition of expected project related IRR (*pexIRR*) and equity related IRR (*eexIRR*) is based on *WACC* calculation principles provided by the Estonian Competition Authorities in *Manual for Calculation of Weighted Average Cost Of Capital* [41] and are:

- *pexIRR* = 7.3%;
- *eexIRR* = 9.61%.

3.17.5 Forecast related initial data

By default heat demand ($Corr^{heat.demand}{}_t$) the correction factor is 0%, i.e. heat demand is constant during the CHP planning period. The following correction factors correlate with the average inflation rate forecast provided by the Bank of Estonia and are equal to 2% for each year during the CHP planning period [42]:

- $Corr^{heat.demand}{}_t$ – heat demand correction factor;
- $Corr^{FUELPRICE}{}_t$ – fuel price correction factor;
- $Corr^{QUOTAPRICE}{}_t$ – CO_2 quota price correction factor;
- $Corr^{ASHPRICE}{}_t$ – ash disposal price correction factor;
- $Corr^{FIXEDOM}{}_t$ – fixed O&M costs correction factor;
- $Corr^{VOM}{}_t$ – variable O&M costs correction factor;
- $Corr^{ELPRICE}{}_t$ – electricity price correction factor;
- $Corr^{HEATPRICE}{}_t$ – electricity price correction factor.

3.17.6 Environmental fees related initial data

The pollution charge rates upon emission of pollutants into the ambient air are defined in [16]. The charge rates are given until the year 2015. Regarding [16], the charge rates depend on the location of stationary pollution sources. The pollution charges per one ton of pollutant for the years from 2010 to 2015 are shown in *Table 3.6*.

The pollution charge rates provided in *Table 3.6.* will be increased by a factor:

- 1.2 if the pollutants are released into the ambient air from stationary sources of pollution located within the boundaries of local governments bordering on the Narva River, if the height of release of pollutants is more than 100 metres above the ground level;
- 1.5 if the pollutants are released into the ambient air from stationary sources of pollution located within the boundaries of the administrative territory of Jõhvi, Kiviõli, Kohtla-Järve, Narva, Sillamäe or Tartu;
- 2 if the pollutants are released into the ambient air from stationary sources of pollution located within the boundaries of the administrative territory of Tallinn;
- 2.5 if the pollutants are released into the ambient air from stationary of pollution located within the boundaries of the administrative territory of Haapsalu, Kuressaare, Narva-Jõesuu or Pärnu.

Table 3.6. Pollution charge rates per one ton of pollutant

	€/t					
POLLUTANT	2010	2011	2012	2013	2014	2015
Carbon dioxide, CO_2	2.0	2.0	2.0	2.0	2.0	2.0
Sulphur dioxide, SO_2	39.4	51	66.21	86.08	111.90	145.46
Nitrogen oxides, NO_x	76.4	83.53	91.90	101.10	111.20	122.32
Carbon monoxide, CO	4.8	5.25	5.78	6.35	6.99	7.7
Particulates[1]	39.4	51.19	66.53	86.47	112.42	146.16
Volatile organic compounds[2]	76.4	83.53	91.90	101.10	111.20	122.32
Heavy metals	1216	1228	1240	1252	1265	1278

[1] – except for heavy metals and compounds of heavy metals.

[2] – except for mercaptans.

No increase factors for the default values are used to avoid complicity. *Table 3.6.* shows the designations of the data provided in *Table 3.7.*

Table 3.7. Pollution charge rates related data designation

	€/t					
POLLUTANT	rT_0	rT_1	rT_2	rT_3	rT_4	rT_5
Carbon dioxide, CO_2	rCO_0	rCO_1	rCO_2	rCO_3	rCO_4	rCO_5
Sulphur dioxide, SO_2	$rSO2_0$	$rSO2_1$	$rSO2_2$	$rSO2_3$	$rSO2_4$	$rSO2_5$
Nitrogen oxides, NO_x	$rNOx_0$	$rNOx_1$	$rNOx_2$	$rNOx_3$	$rNOx_4$	$rNOx_5$
Carbon monoxide, CO	rCO_0	rCO_1	rCO_2	rCO_3	rCO_4	rCO_5
Particulates	rP_0	rP_1	rP_2	rP_3	rP_4	rP_5
Volatile organic compounds	$rVOC_0$	$rVOC_1$	$rVOC_2$	$rVOC_3$	$rVOC_4$	$rVOC_5$
Heavy metals	rHM_0	rHM_1	rHM_2	rHM_3	rHM_4	rHM_5

To select the environmental fees related initial data the following steps are taken:

1). If $rT_5 \leq T_{com}$ then

$Corr^{CO2RATE}{}_t = Cor^{SO2RATE}{}_t = Cor^{NOxRATE}{}_t = Cor^{PARTRATE}{}_t = Cor^{VOCRATE}{}_t =$
$= Cor^{HMRATE}{}_t = Cor^{CORATE}{}_t = 2\%$;

$RATEco2 = rCO2_5;$

$RATEso2 = rSO2_5;$

$RATEnox = rNOx_5;$

$RATEco = rCO_5;$

$RATEpart = rP_5;$

$RATEvoc = rVOC_5;$

$RATEhm = rHM_5;$ else go to step 2.

2). For i=0 to 5. If $rT_i=T_{com}$ then

$RATEco2 = rCO2_i;$

$RATEso2 = rSO2_i;$

$RATEnox = rNOx_i;$

$RATEco = rCO_i;$

$tRATEpart = rP_i;$

$RATEvoc = rVOC_i;$

$RATEhm = rHM.$

For t=2 to 6-i

$$Corr^{CO2RATE}{}_t = rCO2_i / rCO2_{i\text{-}1} \times 100; \tag{4.69}$$

$$Corr^{SO2RATE}{}_t = rSO2_i / rSO2_{i\text{-}1} \times 100; \tag{4.70}$$

$$Corr^{NOxRATE}{}_t = rNOx_i / rNOx_{i\text{-}1} \text{ x} \times 100; \tag{4.71}$$

$$Corr^{CORATE}{}_t = rCO_i / rCO_{i\text{-}1} \times 100; \tag{4.72}$$

$$Corr^{PARTRATE}{}_t = rP_i / rP_{i\text{-}1} \times 100; \tag{4.73}$$

$$Corr^{VOCRATE}{}_t = rVOC_i / rVOC_{i\text{-}1} \times 100; \tag{4.74}$$

$$Corr^{HMRATE}{}_t = rHM_i / rHM_{i\text{-}1} \times 100. \tag{4.75}$$

3.17.7 Other initial data

By default the following values for other initial data are used:

- Project start-up year (T_{start}) is a current year plus 1.
- The year of plant commercial operation (T_{com}) is a project start-up year plus 1.
- Length of the project (T_{length}) is 30 years.
- Standard reference temperature ($temp_{ref}$) for n temperature-depended consumer is 18°C [43].
- Regarding [44], if CO_2 trading will be prolonged after 2012, the CO_2 quota price level (*PRICEquota)* could range from 20 up to 35 €/t. The value of 25€/t is used by default for the reference year.
- Regarding to information obtained from different landfill owners, the average expected ash removal costs (*PRICEash*) for the year 2012, including ash transportation to the landfill and storing there are 45 €/t.

- The increase of ash weight in comparison to the disposed dry ash weight (*DISPwet)* is 0%. It is assumed that the dry ash removal system is used.
- *DISPash* – the share of ash to be disposed by the ash disposal system is 99%. It is assumed that effective fuel gas cleaning systems are used and almost all captured ash is removed to the landfill.
- Electricity price (*PRICEel*) is 45 €/MWh, that corresponds to the Nordpool SPOT average price for the Estonian area [45].
- Heat loss in district heating network (*HEATloss)* is 20% [9].
- By default the heat price (*PRICEheat*) is 42 €/MWh, which is equal to the average heat price for biomass based boiler houses [46].

4 COMPUTER PROGRAM

4.1 Requirements and development status

A Microsoft (MS) Excel based application/program is created based on the mathematical model proposed in Chapter 3. The initial data as well as calculation algorithms described previously are used. The MS Excel based application is a trial version to show the abilities of the mathematical model for different ways of computation.

In order to add value to the mathematical model, the development of a web based application using the model is in progress. The web based application will give an opportunity to access the calculations from anywhere and at any time, by using a computer connected to the web and web browser while the right user login data is necessary. The web based application will also help to save the disk space.

The use of web based application will allow the updating process in the easiest way where all changes and new features are delivered to the program users automatically.

The development of the web based application is in progress. At the moment the heat load modelling part is being tested and shows functioning without noticeable errors. The work on other parts is going on.

All information regarding the stage of development of the program is available on the web page *www.bioesk.com.*

The development of the web based application depends on the available funds. For the time being the main goal is to prepare functioning application based on the proposed mathematical model within the financing conditions of the PHD study provided by the Nordic Energy Research. Further development of the project will depend on the interest in the proposed model, availability of funds and goals of financed activities.

4.2 Trial calculation

The MS Excel based application was used to show the abilities of the mathematical model for the different ways of computation. The analysis of results derived with the use of proposed mathematical model based application is shown below. Full information regarding calculations is provided in the appropriate published articles.

4.2.1 Heat load simulation

The evaluation results [V] of the heat load simulation model show the simplicity of the use of proposed district heating load modelling method in most cases (district heating consumers could be more or less classified as constant, or temperature-dependent heat load consumers). This method is suitable for pre-feasibility and feasibility studies where the district heating load profile modelling is necessary and uncertainty level presupposes certain inaccuracy of modelling. The trial calculations show that simulated and measured district heating network load profiles are very close to each other. As an exception, there are transitional periods (late spring and the beginning of autumn) when the simulated heat loads are higher than measured values.

For the future, the proposed model could be improved by using correction factors to increase the accuracy of transitional periods modelling. The correction factor should consider the contribution of cold water temperature, solar irradiation, wind speed and other factors, which affect the heat load profile formation.

4.2.2 Competitiveness of CHP technologies in Estonian conditions

Modelling results [IV] show that the technologies for smaller CHP applications are more expensive (specific price) and less efficient than those for larger CHP plants.

At present peat is considered a good alternative for woodchips. Lower fuel price (11.7 €/MWh) smooths over the higher ash handling costs and pollution charges than those for woodchips. At the same time woodchips are more preferable because of higher feed-in tariffs for the produced electricity.

The advantages of gas engine CHP plants are relatively low investment costs and high electrical efficiency. But because of high natural gas price (MWh_{fuel} price is 2.5 – 3 times higher than for wood chips and peat) and relatively high fixed O&M costs the calculated heat prices are the highest. Heat price for the expected 7% IRR is between 53 and 61 €/MWh_{heat} depending on heat demand.

An under 5 MW_{el} ORC is competitive to the steam engine and steam turbine technologies. The calculated heat prices are lower for 1 – 4 €/MWh_{fuel} where higher fuel price difference corresponds to places with lower heat demands.

The heat prices for the locations with annual heat demand under 20000 MWh are mainly above 45 €/MWh_{fuel} where the average heat prices for biomass boiler houses remain between 40 – 45 €/MWh_{heat}. Developing of CHP plants in such heat demand areas is feasible in the case of receiving grant payments for the investments.

A CHP plant development based on woodchips or peat could be feasible without grant payments in the places where the annual heat demand exceeds 30000 – 40000 MWh. A carefully selected CHP technology and capacity can afford higher IRR when keeping the heat prices competitive.

The most feasible places for CHP expansion in Estonia are Maardu, Viljandi, Rakvere, Valga, Haapsalu, Võru, Paide and Põlva.

4.2.3 Feed-in tariffs

To estimate the impact of feed-in tariffs on CHP, the cost price of electricity is calculated. The cost price is defined as a price of electricity that is sold for the production cost without any profit for the producer. Calculations are provided for biomass based CHP plants with the nominal net electrical capacity of 1, 10 and 25 MW_{el}.

The calculation results [I] shows that the estimated electricity cost prices of biomass based CHP plants vary significantly. The cost price (without feed-in tariffs) for 25 MW_{el} CHP plant is 54 €/MW_{el}, that for 10 MW_{el} 72 €/$MW_{el,}$ and 145 €/MW_{el} for 1 MW_{el} CHP plant.

For the time being, in Estonia the feed-in tariff is fixed for all renewable fuels, including biomass. The feed-in tariff does not take into account special features of electricity production technologies, plant capacity factor, fuel types, available operation time etc. Consideration of previously mentioned factors in feed-in tariff formation could significantly increase the reasonability of distributed funds, in other words to avoid subsidising the projects which can cover the expenditures without subsidies and support the aid requiring optimum level projects (minimizes risks of over-compensating the economically efficient plants). At the same time the implementation and evaluation of stepped tariff design can lead to high administrative complexity. Many different tariff levels within the same technology may lead to less transparency and uncertainty for the investors.

The trial calculations presented in this paper as well as comparison to feed-in tariffs designs in other EU countries shows the necessity to improve the feed-in tariff design in Estonia. To make it more efficient it could be reasonable to look for the cooperation with other countries and organisations, as an example, the International Feed-In Cooperation.

4.2.4 Case-specific calculation

This chapter provides a more accurate overview on the case-specific calculation based on the proposed model in comparison to the calculations provided in articles described in Chapters 4.2.1 – 4.2.3. The descriptions of calculation processes in these articles are restricted to the maximum allowed size of publication and goal of articles.

The main goal of this chapter is to show practical implementation possibilities and calculation logics of the proposed mathematical model based on a trial exercise. The trial calculations will be provided for the Kuressaare municipality on the island Saaremaa where a biomass (wood chips) based CHP plant is being planned. The heat sale and heat loss in the Kuressaare district heating area are 65000 MWh/year and 13700 MWh/year (17%), respectively. The heat demand for hot water makes 15% of the total heat demand in the district heating area and is 11800MWh/year. [50]

The tasks for calculations are:

- With using the proposed mathematical model consider the applicability of a steam turbine and ORC technologies for the Kuressaare municipal district heating area. The calculations should be provided for the power plants with the nominal capacity of 1.5, 2 and 3 MW_{el} for the purpose of optimizing the CHP plant capacity.

- The calculations should be provided with and without possible grant payments in the amount of 50% of total investment costs regarding the regulation [20]. At the moment the application of this regulation is limited to the availability of funds. Because of that it is important to calculate both grant payment scenarios to estimate the economical risks of the project.
- The primary energy savings for all CHP expansion alternatives should be estimated.

The comparison of alternatives, which includes calculations for two different technologies, three different capacities and two economic assumptions, requires 12 simulations. Is spite of that the main part of calculations is quite similar to all alternatives (heat load modelling and fuel selection are similar).

The initial data used for the calculation is mainly taken from the model's internal database, which reflects the average values for Estonia (see Chapter 3.17). However, some of them have been replaced by other values obtained from the free sources, which are more case specific. The initial data components, which differ from the model's internal database values, are shown below:

- The active development phase of the project will start in 2012. The plant will be launched in 2013;
- The price for the heat produced in the CHP plant in the first operation year should not exceed the price of heat from the existing boiler house, which is 40 EUR/MWh_{heat};
- The investor's expected minimum IRR on equity is 9%;
- Financing of the project is based on the equity capital and grant payment (if available) of the Kuressaare District Heating Company. No loans are expected.

The description of modelling steps is given below.

Heat load is calculated based on the algorithms given in Chapter 3.2. According to the proposed heat load modelling principles, the Kuressaare heat demand is formed by the annual 53200 MWh temperature dependent heat consumption, 11800 MWh/year hot water consumption and 13700 MWh/year heat losses (both are constant heat loads). The calculated Kuressaare heat load profile is shown in Figure 4.1.

The calculation of *costs and revenues* for the *CHP plant* is provided based on the equations shown in Chapters 3.5, 3.7 – 3.13.

The cash flow is calculated based on the principles described in Chapter 3.14.

Estimation of the cash flow based *measures for investments* goes as described in Chapter 3.15.

The use of *internal database* of the mathematical model is provided according to Chapter 3.17.

The primary energy savings are estimated based on the principle described in Chapter 3.16.

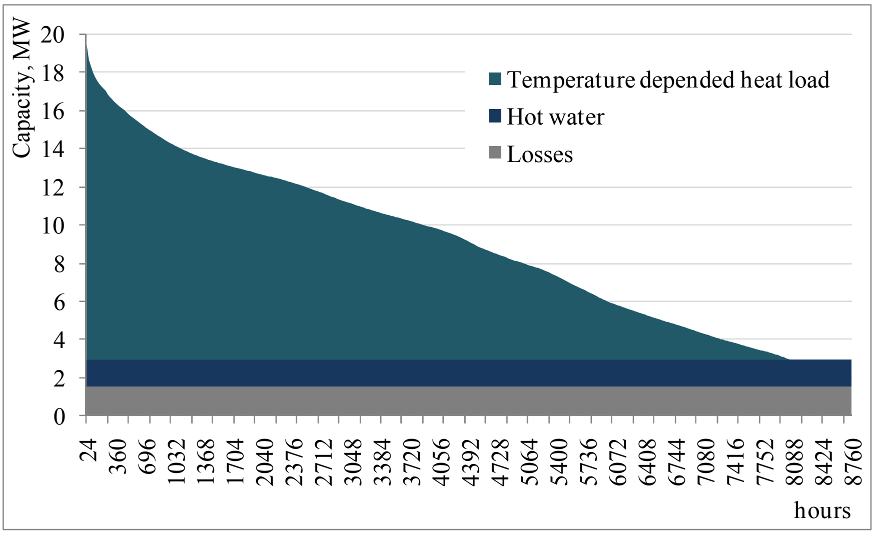


Figure 4.1 Heat load duration curve for the Kuressaare district heating area

The trial exercise implies calculations for all the case specific alternatives. *Table 4.1.* shows the results of CHP plant costs, revenues and cash flows modelling for a 1.5 MW ORC technology based CHP plant alternative without subsidies.

Table 4.1. The calculation results of CHP plant costs, revenues and cash flows (in M€) for a 1.5 MW steam turbine technology based CHP plant

nr.	1	2	3	4	5	6	7	8	9	10
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Investment	7.31									
Fuel costs		1.30	1.33	1.35	1.38	1.41	1.44	1.47	1.49	1.52
Fixed O&M costs		0.18	0.19	0.19	0.19	0.20	0.20	0.21	0.21	0.21
Variable O&M costs		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Ash disposal costs		0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Environmental fees		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Electricity sales		0.50	0.51	0.52	0.53	0.54	0.55	0.56	0.57	0.59
Feed-in tariffs		0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57
Heat sales		1.61	1.64	1.67	1.70	1.74	1.77	1.81	1.84	1.88
Cash flow	-7.31	1.14	1.15	1.16	1.18	1.19	1.20	1.21	1.23	1.24
Cumulative cash flow	-7.3	-6.2	-5.0	-3.9	-2.7	-1.5	-0.3	0.9	2.2	3.4

nr.	11	12	13	14	15	16	17	18	19	20
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Investment										
Fuel costs	1.55	1.59	1.62	1.65	1.68	1.72	1.75	1.79	1.82	1.86
Fixed O&M costs	0.22	0.22	0.23	0.23	0.24	0.24	0.25	0.25	0.26	0.26
Variable O&M costs	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Ash disposal costs	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04
Environmental fees	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Electricity sales	0.60	0.61	0.62	0.63	0.65	0.66	0.67	0.69	0.70	0.71
Feed-in tariffs	0.57	0.57	0.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Heat sales	1.92	1.96	2.00	2.04	2.08	2.12	2.16	2.20	2.25	2.29
Cash flow	1.25	1.27	1.28	0.72	0.73	0.75	0.76	0.78	0.80	0.81
Cumulative cash flow	4.7	5.9	7.2	7.1	8.7	9.4	10.2	10.9	11.7	12.6

nr.	21	22	23	24	25	26	27	28	29	30
Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Investment										
Fuel costs	1.90	1.93	1.97	2.01	2.05	2.09	2.13	2.18	2.22	2.27
Fixed O&M costs	0.27	0.27	0.28	0.28	0.29	0.29	0.30	0.31	0.31	0.32
Variable O&M costs	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04
Ash disposal costs	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05
Environ-mental fees	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Electricity sales	0.73	0.74	0.76	0.77	0.79	0.80	0.82	0.84	0.85	0.87
Feed-in tariffs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Heat sales	2.34	2.39	2.43	2.48	2.53	2.58	2.63	2.69	2.74	2.80
Cash flow	0.83	0.84	0.86	0.88	0.90	0.91	0.93	0.95	0.97	0.99
Cumulative cash flow	13.4	14.2	15.1	16.0	16.9	17.8	18.7	19.6	20.6	21.6

IRR	15.1%
NPV at 9% IRR	3.42
PES	20.8%

Modelling of other alternatives is also provided. The modelling results are systematized and shown in *Table 4.2*.

Table 4.2. Modelling results of case specific calculations

Technology	Power plant parameters at nominal electrical capacity			Measures of investments				PES
				Without subsidy		With subsidy		
	Electrical capacity	Heat capacity	Electrical efficiency	Project IRR	Project NPV[1]	Equity IRR	Equity NPV[2]	
	MW	MW	%	%	M€	%	M€	%
Steam turbine	1.5	6.2	16.5	15.1	3.42	32%	6.77	20.8
	2	8.0	17	13.5	3.24	29%	7.60	20.8
	3	11.2	18	9.9	0.84	22%	7.03	21.2
ORC technology	1.5	6.9	15.1	19.5	5.54	40%	8.55	20.3
	2	9.1	15.3	18.0	6.09	37%	9.99	20.3
	3	13.5	15.5	14.6	5.16	31%	10.66	20.2

[1]- Project NPV at 9% expected IRR

[2]- Equity NPV at 9% expected IRR

An analysis of the calculation outputs gives the following answers to the formulated tasks in the previously stated trial exercise:

- Both the steam turbine and ORC technologies could be successfully implemented for the Kuressaare CHP expansion project. The ORC looks a little bit more preferable due to the higher expected measures of investments. It is reasonable to install a 2 MW_{el} ORC unit. This capacity will allow achieving a higher project related NPV and acceptable IRR.
- The applicability of investment subsidies will allow almost doubling the equity IRR and significantly increased NPV of the project. The lack of investment subsidy is not critical to the project implementation. For all alternatives the calculated IRR remains below the expected minimum.
- Implementation of all alternatives will allow achieving primary energy savings in the range of 20% in comparison to the separate heat and power production based on the same fuel.
- As a result of case specific calculations, it is reasonable to proceed with the 2 MW_{el} capacity ORC based CHP plant, which is an economically reasonable, environmental friendly and primary energy efficient solution. The availability of investment subsidies will allow increasing the profitability of the CHP plant or reducing the heat price in comparison to the current price level.

It is important to mention that the trial exercise calculation is only a part of different tasks to be solved based on the proposed mathematical model. All kinds of sensitive analyses can be provided as the need arises. A key for the success of calculations is an understanding of case specific features and clear definition of modelling tasks.

CONCLUSION

The basic conceptual model, simplified conceptual model and mathematical models for a CHP plant are composed. The use of mathematical model based MS Excel application is discussed.

The composed basic conceptual model involves the main objects and factors in the CHP plant operating activities that affect the plant viability, as well as their interrelations. The components and interactions mentioned in the conceptual model are discussed.

Development of the conceptual model is the most important part of the modelling process. The conceptual model is the foundation for the quantitative, mathematical presentation of the object/process (mathematical model), which in turn is the basis for the computer code used for simulation.

Simplified conceptual model is created by filtering the data not valid or non-typical for Estonian conditions from the basic conceptual model and concretizing some of the data natural for the Estonian energy sector. The composition of the simplified conceptual model is based on the analysis of current legislation, available information and experience obtained during the participation in CHP plant related pre-feasibility and feasibility studies for different locations in Estonia (e.g. Tallinn, Tartu, Pärnu, and Jõgeva).

Mathematical model of a CHP plant is based on the simplified conceptual model. The mathematical model quantifies the state of any component as a numeric variable; the processes are described by using a series of mathematical equations.

The mathematical model provides calculations on the pre-feasibility level, makes possible providing a preliminary assessment of technical and economic viability of the proposed project, estimates the cost of development and operation, assesses anticipated benefits and preliminary economic criteria for evaluation.

Based on the mathematical model the Microsoft (MS) Excel based application/program is created. A MS Excel based application was used for:

- The investigation of the impact of subsidy mechanisms on biomass based electricity cost prices [I].
- The estimation of competitiveness of combined heat and power plant technologies in Estonian conditions where the main criteria to indicate the preference of CHP technology is the heat price by which the internal rate of return corresponds to investors' expectations [IV].
- The calculations of different CHP expansion scenarios (different technologies, fuels and available subsidies) in a 30000 MWh district heating area [VIII].

- Some case-specific consultant arrangements regarding the implementation of combined heat and power production.

To add a value to the mathematical model, the development of web based application using the model is in progress. The heat load modelling, technology and fuel selection/defining parts have been prepared, tested and function without noticeable errors. The work on other parts is going on.

The environment which has influence on the investments in renewable energy and CHP production has a lot of issues which have to be solved:

- The energy related legislation is not stable. Too frequent changes both in values and in fulfilling the terms and conditions for feed-in tariffs affect the economic activity of Energy Companies. It does not support investments, although the main target of energy related legislation is opposite.
- The estimation methods of factors and values as well as their interpretation differ. For example, the rules and requirements for business plans in energy projects and projects with subsidy application from governmental institutions, methods for evaluating the maximum heat sale price, methods for calculating the feed-in tariffs, etc.
- The initial technical and economic data used for calculations of CHP plant related issues is different. For example, there is no accepted forecast for fuel prices, electricity prices. No methods for collecting, systematizing and updating the data have been approved.

The author hopes that the description of approaches and principles regarding the analysis on technical and economic consequences of renewable energy based CHP systems provided in this study will be noticed by the parties influencing CHP expansion in some way. The implementation and further development of proposed methods and principles will help to establish regular communication between the parties, make their work more efficient, provide investors with clear, stable and common decision making rules and use that increased amount of decisions to invest in environmentally friendly and energy efficient approaches of energy production.

The author believes that the government authorities and institutions should support the collection, systematization and publication of technical data concerning the energy sector for the purpose of promoting the joint operation of government authorities and public sector. Operation with identical technical and economic figures could significantly improve mutual understanding in the economic evaluation of CHP related projects and their necessary backing. The implementation of this system should be provided by the government authorities, Estonian Climate and Energy Agency, Tallinn University of Technology or other, experienced government or private organizations, institutions and enterprises.

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II. **Latõšov, E.**; Siirde, A.; Kleesmaa, J. (2010). The impact of pollution charges, ash handling and carbon dioxide to cost competitiveness of fuel sources for energy production in Estonia. Scientific proceedings of Riga Technical University. Environmental and Climate Technologies, 1 – 6.

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VI. Volkova, A.; **Latosov, E.**; Siirde, A. (2009). Small-scale CHP potential in Latvia and Estonia. Scientific Proceedings of Riga Technical University.13 Environmental and Climate Technologies (127 – 134). Riga Technical University

VII. **Latõšov, E.**; Siirde, A. (2009). Possibilities of using biofuel small scale combined heat and power plants in Estonia. Lahtmets, R. (Editor). 6th International Symposium "Topical Problems in the Field of Electrical and Power Engineering", Doctoral School of Energy and Geotechnology. Kuressaare, Estonia, 12.01. – 17.01.2009 (89 – 92). Estonian Society of Moritz Hermann Jacobi.

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IX. **Latõšov, E**.; Siirde, A. (2008). Methodology and structure of a computational model for estimating the economic and technical profitability of small scale combined heat and power plants. In: The 11th International Symposium on District Heating and Cooling: University of Iceland, 2008, 274 – 278.

ABSTRACT

The main target of the study is to create a mathematical model for planning the CHP plant construction. The composition of the mathematical model is provided based on the general-to-particular method of approach.

Firstly the basic conceptual model has been composed. The basic conceptual model describes the main objects and factors involved in the CHP plant operating activities and affecting the plant viability, as well as their interrelations.

Secondly the simplified conceptual model is created by filtering the data not valid or non-typical for Estonian conditions from the basic conceptual model, which concretizes some of the data natural for the Estonian energy sector.

Thirdly a mathematical model is created based on the simplified conceptual model. The mathematical model quantifies the state of any component as a numeric variable; the processes and interactions are described by using a series of mathematical equations.

Based on the mathematical model the Microsoft (MS) Excel based application/program has been created. A MS Excel based application is used for the investigation of the impact of subsidy mechanisms on biomass based electricity cost prices, estimation of competitiveness of combined heat and power plant technologies in Estonian conditions, calculations for different CHP expansion scenarios (different technologies, fuels and available subsidies) in 30000 MWh district heating area and some case-specific consultant arrangements regarding the implementation of combined heat and power production.

The development of the web based application using the model is in progress.

Keywords: CHP planning, mathematical model, primary energy efficiency, simulation, local fuels, CHP technologies.

KOKKUVÕTE

Töö peamiseks eesmärgiks on koostada koostootmisjaama planeerimise matemaatiline mudel. Matemaatilise mudeli koostamisel on kasutatud üldiselt üksikule lähenemismeetodit.

Esmalt on koostatud üldine kontseptuaalne mudel. Üldine kontseptuaalne mudel käsitleb põhilisi objekte ja faktoreid, mis on seotud koostootmisjaama tööga ja mis mõjutavad jaama elujõulisust.

Kontseptuaalse mudeli koostamine on modelleerimise protsessi olulisem osa. Kontseptuaalne mudel on alus objektide/protsesside arvuliseks, matemaatiliseks kirjeldamiseks, mis omakorda on modelleerimise arvutuskoodi loomise alus.

Teiseks on loodud lihtsustatud kontseptuaalne mudel, mille koostamisel üldises kontseptuaalses mudelis käsitletud faktoreid ja objekte on korrigeeritud vastavalt Eesti energeetikasektorit iseloomustavatele andmetele/näitajatele. Lihtsustatud kontseptuaalne mudel on koostatud kehtiva seadusandluse ja Eesti erinevates piirkondades (näiteks Tallinn, Tartu, Pärnu, Jõgeva) uuringute tegemise käigus omandatud kogemuse alusel.

Kolmandaks on koostatud matemaatiline mudel, mis põhineb lihtsustatud kontseptuaalsel mudelil. Matemaatilises mudelis on iga komponendi olek määratud arvväärtustega. Protsesse ja seoseid on kirjeldatud matemaatiliste võrranditega.

Matemaatiline mudel võimaldab arvutused läbi viia vähemalt eeluuringu tasemel, s.t. hinnata projekti tehnilist ja majanduslikku otstarbekust, määrata projekti arendamise ja käitlemise kulud ning välja arvutada projekti kasumlikkuse näitajad.

Matemaatilise mudeli põhjal on koostatud MS Exceli töötabelitel põhinev programm/rakendus. Seda rakendust on kasutatud erinevate toetuste mõju väljaselgitamiseks biokütustel töötavate koostootmisjaamade elektri omahinnale, koostootmise tehnoloogiate konkurentsivõime hindamiseks Eesti tingimustes ja erinevate koostootmise stsenaariumite (erinevad tehnoloogiad, kütused ja kättesaadavad toetused) läbiarvutamiseks 30000 MWh soojusnõudlusega kaugküttepiirkonnas. Ülalmainitud arvutused on avaldatud doktoriõppe käigus koostatud artiklites (vt. publitseeritud artiklite nimekirja). Sama matemaatilist mudelit on kasutatud ka konsultatsiooniteenustes koostootmise rakendamise otstarbekusele eelhinnangute andmisel mõne konkreetse asukoha kohta.

Arendamisel on matemaatilisel mudelil põhinev veebirakendus. Selle eesmärgiks on väärtustada matemaatilist mudelit, suurendades kaasaegsete veebipõhiste rakenduste arendamise meetodite kaasamisega selle kasutamise tõhusust. Käesolevaks ajaks on soojuskoormuse modelleerimise, tehnoloogia ja kütuse valiku osad koostatud ja testitud. Rakenduse teised osad on koostamisel.

Autor loodab, et käesolevas töös kirjeldatud koostootmisjaamade tehnilise ja majandusliku otstarbekuse hindamise meetodid leiavad koostootmise arendajate tähelepanu. Pakutud meetodite ja põhimõtete kasutamine ning arendamine aitab kaasa regulaarse suhtlemise tekkimisele koostootmise teemaga seotud osapoolte vahel, teeb nende töö efektiivsemaks, annab investoritele selged ja püsikindlad otsustamise reeglid, suurendes sellega keskkonnasõbralikesse ja efektiivsetesse energiatootmisviisidesse investeerimise kohta tehtavate positiivsete otsuste hulka.

Autor arvab, et riiklikud institutsioonid peaksid toetama energiasektorit puudutavate tehniliste andmete kogumist, süstematiseerimist ja analüüsi eesmärgiga tõhustata koostööd riikliku ja erasektori vahel. Sarnaste tehniliste ja majanduslikke näitajate kasutamine parandab oluliselt sektorite omavahelist arusaamist koostootmisprojektide majandustegevusest ja nende toetamise vajadusest. Andmete käitlemisesüsteemi loomist peaks tagama vastavad riigiasutused, Kliima- ja Energiaagentuur, Tallinna Tehnikaülikool või mõni muu sel alal kogemust omav organisatsioon.

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Tallinn University of Technology	2007	Thermal Engineering / M.Sc.
Tallinn University of Technology	2005	Thermal Engineering / Bachelor
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4. Language competence/skills (fluent; average, basic skills)

Language	Level
Estonian	Very Good
English	Good
Russian	Mother tonque

5. Special Courses

Period	Educational or other organisation
2005 – 2005	Design and Operation of Hydrogen Aided Energy Systems, University of Applied Sciences Stralsund, Germany

6. Professional Employment

Period	Organisation	Position
2006 – present	ÅF-Estivo	Energy Specialist

2008 – 2010	Tallinn University of Technology, Department of Heat Engeneering	Researcher

7. Scientific work

Latõšov, E. ; Siirde, A. (2010). Competitiveness of Combined Heat and Power Plant Technologies in Estonian Conditions.

Latõšov, E.; Siirde, A. (2010). Heat load model for small-scale CHP planning.

Latõšov, E.; Siirde, A.; Kleesmaa, J. (2010). The impact of pollution charges, ash handling and carbon dioxide to cost competitiveness of fuel sources for energy production in Estonia.

Anna Volkova, Eduard Latošõv, Andres Siirde (2010). Use of multi-criteria decision analysis for choosing an optimal location for a wood fuel based cogeneration plant: a case study in Estonia.

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8. Defended theses

Master Thesis: Computer Program to Estimate the Applicability of Bio Fuel Combined Heat and Power Plants, 2007, Supervisor Allan Vrager, TUT

9. Main areas of scientific work/Current research topics

- District heating networks
- Heat and power generation technologies
- Pump storage plants
- Biofuels

10. Other research projects

Consulting Assignments:

2010 – 2010, Merko, Tallinn
Pre-feasibility Study, Possibilities to Construct CHP Plants in Estonia

2010 – 2010, AS Viisnurk, Pärnu
Pre-feasibility Study for CHP Plant Construction

2010 – 2010, AS Eraküte, Tartu
Pre-feasibility Study for CHP Plant at AS Eraküte Tartu District Heating Area

2009 – 2010, Eesti Energia Mining Company, Narva
Feasibility Study Regarding the Handling and Storage of Oil Shale, Biomass and Rubber Chips at Eesti Power Plant

2009 – 2010, Narva Oil Factory, Narva
Narva Oil Plant Recovery Boiler Reconstruction

2009 – 2010, Narva Power Plants, Narva
SOx Emission Reduction with Primary Methods on Pulverized Combustion Oil Shale Boilers

2009 – 2010, Estonian Competition Authority, Tallinn
Peer Review for Wood Chips and Bark Fueled Boiler House Investment and O&M Costs

2009 – 2010, Tartu Power Plant, Tartu
Tartu CHP Plant Auxiliary Cooling System Tender Documentation Preparation and Owner Engineering Services

2009 – 2009, Eesti Energia, Tallinn
Gas Engine Based CHP Unit Technical Description

2009 – 2009, 4-Energia, Tallinn
Pre-Feasibility Study for Pump Storage Power Plant

2009 – 2009, Gas Power, Tallinn
Pre-Feasibility Study for Establishing 200 MWe Gas Turbine Power Plant

2009 – 2009, Dalkia, Jõgeva
Energy Supply Analyze of Jõgeva Town and Technical Solution for New Boiler Plant

2008 – 2008, Eesti Energia Põhivõrk, Tallinn
Pre-Feasibility Study for Establishing Gas Turbine Power Plant for Eesti Energia Põhivõrk

2007 – 2008, Iru PP Ltd, Maardu
Feasibility Study for Waste to Energy Plant in Iru Power Plant

2007 – 2008, Tartu KTJ, Tartu
Feasibility Study for Waste to Energy Plant in Tartu City

2008 – 2008, AF Consult Oy, Finland
Multi-Criteria Analysis for Narva Power Plants Ash Removal System Renovation

2007 – 2008, Narva Power Plants, Estonia
Environment Impact Assessment of Energy Complex of Narva PP

2006 – 2007, Narva Power Plants, Narva
Eesti Power Plant District Heating System Renovation

2006 – 2006, Eesti Energia, Tallinn
Pre-Feasibility Study. Possibilities of Heat and Electricity Cogeneration in Different Regions of Estonia

2006 – 2007, Tartu University, Kääriku
Heat Supply System Renovation of Kääriku Sport Centre and Energy Audit for Buildings

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Pre-Feasibility Study. Straw Pellets Production

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Õppeasutus (nimetus lõpetamise ajal)	Lõpetamise aeg	Haridus (eriala/kraad)
Tallinna Tehnikaülikool	2007	Soojustehnika/ Magister
Tallinna Tehnikaülikool	2005	Soojustehnika/Bakalaureus
Valdeku gümnaasium	2002	Keskharidus

4. Keelteoskus (alg-, kesk- või kõrgtase)

Keel	Tase
Eesti	Väga hea
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Vene	Emakeel

5. Täiendusõpe

Õppimise aeg	Täiendusõppe läbiviija nimetus
2005 – 2005	Vesiniku baasil energiasüsteemide planeerimine ja kasutamine, Stralsund Rakendusteaduste ülikool, Saksamaa

6. Teenistuskäik

Töötamise aeg	Tööandja nimetus	Ametikoht
2006 – …	AF-Estivo AS	Energeetikaspetsialist
2008 – 2010	Tallinna Tehnikaülikool, Soojustehnika instituut	Erakorraline teadur

7. Teadustegevus

Latõšov, E. ; Siirde, A. (2010). Competitiveness of Combined Heat and Power Plant Technologies in Estonian Conditions.

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Latõšov, E.; Siirde, A. (2008). Methodology and structure of a computational model for estimating the economic and technical profitability of small scale combined heat and power plants.

8. Kaitstud lõputööd

Magistritöö: Arvutusprogramm biokütustel töötavate koostootmisjaamade ehitamise otstarbekuse hindamiseks Eestis, 2007, Juhendaja Allan Vrager, TTÜ

9. Teadustöö põhisuunad

- Kaugküttevõrgud
- Elektri ja soojuse tootmistehnoloogiad
- Pumpelektrijaamad
- Biokütused

10. Teised uurimisprojektid

Konsultatsioonid:

2010 – 2010, Merko, Tallinn
Koostootmisjaamade Rajamise Võimalused Eestis

2010 – 2010, AS Viisnurk, Pärnu
Eeluuring Koostootmisjaama Ehitamiseks AS Viisnurk

2010 – 2010, AS Eraküte, Tartu
AS Eraküte Tartu Võrgupiirkonna Soojuse ja Elektri Koostootmisjaama Eelhinnang

2009 – 2010, Eesti Energia Kaevandused, Narva
Feasibility Study Regarding the Handling and Storage of Oil Shale, Biomass and Rubber Chips at Eesti Power Plant

2009 – 2010, Narva Õlitehas, Narva
TSK-140 Utilistasioonkatla Moderniseerimine ja Hankekutsedokumentide Ettevalmistamine

2009 – 2010, Narva Elektrijaamad, Narva
Põlevkivi Tolmpõletuskatla Väävelühendite (SO2) Vähendamine Primaarsete Meetoditega

2009 – 2010, Konkurentsiamet, Tallinn
Eksperthinnang Katlamajade Maksumuse, Tehnilise Lahenduse ja Opereerimiskulude Kohta

2009 – 2010, Tartu Elektrijaam, Tartu
Tartu Elektrijaama Lisajahutussüsteemi Hankedokumentatsiooni Ettevalmistus ja Omaniku Inseneriteenused

2009 – 2009, Eesti Energia, Tallinn
Gaasimootoril Põhineva Koostootmisjaama Tehniline Kirjeldus

2009 – 2009, 4-Energia, Tallinn
Maardu Hüdroakumulatsioonjaama Eeluuring

2009 – 2009, Gas Power, Tallinn
Eeluuring 200MW_{el} Võimsusega Gaasturbiinelektrijaama Rajamiseks

2009 – 2009, Dalkia, Jõgeva
Jõgeva Linna Soojusvarustuse Analüüs ja Eeluuring Kohaliku Kütuse Kasutusele Võtmiseks AS Eraküte Jõgeva Katlamajas

2008 – 2008, Eesti Energia Põhivõrk, Tallinn
Eesti Energia Põhivõrgu Gaasiturbiinelektrijaama Ehitamise Eeluuring

2007 – 2008, Iru Elektrijaam, Maardu
Iru Jäätmeenergia Ploki Teostatavuse Uuring

2007 – 2008, Tartu Elektrijaam, Tartu
Tartu KTJ Jäätmeenergia Jaama Teostatavuse Uuring

2008 – 2008, AF Consult Oy, Soome
Põlevkivituha Transportsüsteemi Renoveerimise Multikriteeriumite Analüüs

2007 – 2008, Narva Elektrijaamad, Eesti
AS Narva Elektrijaamad Energiakompleksi Arendusprojekti KMH ja KSH

2006 – 2007, Narva Elektrijaamad, Narva
Eesti Elektrijaama Soojusvarustussüsteemi Rekonstrueerimine

2006 – 2006, Eesti Energia, Tallinn
Eesti Erinevate Piirkondade Eeluuring Koostootmisjaamade Ehitamiseks

2006 – 2007, Tartu Ülikool, Kääriku
Kääriku Spordibaasi Energiamajanduse Areng

2006 – 2006, Vesmann OÜ, Saaremaa
Eeluuring. Rohtpelletite Valmistamise Võimaluste Uuring

DISSERTATIONS DEFENDED AT TALLINN UNIVERSITY OF TECHNOLOGY ON *MECHANICAL AND INSTRUMENTAL ENGINEERING*

1. **Jakob Kübarsepp**. Steel-bonded hardmetals. 1992.
2. **Jakub Kõo**. Determination of residual stresses in coatings & coated parts. 1994.
3. **Mart Tamre**. Tribocharacteristics of journal bearings unlocated axis. 1995.
4. **Paul Kallas**. Abrasive erosion of powder materials. 1996.
5. **Jüri Pirso**. Titanium and chromium carbide based cermets. 1996.
6. **Heinrich Reshetnyak**. Hard metals serviceability in sheet metal forming operations. 1996.
7. **Arvi Kruusing**. Magnetic microdevices and their fabrication methods. 1997.
8. **Roberto Carmona Davila**. Some contributions to the quality control in motor car industry. 1999.
9. **Harri Annuka**. Characterization and application of TiC-based iron alloys bonded cermets. 1999.
10. **Irina Hussainova**. Investigation of particle-wall collision and erosion prediction. 1999.
11. **Edi Kulderknup**. Reliability and uncertainty of quality measurement. 2000.
12. **Vitali Podgurski**. Laser ablation and thermal evaporation of thin films and structures. 2001.
13. **Igor Penkov**. Strength investigation of threaded joints under static and dynamic loading. 2001.
14. **Martin Eerme**. Structural modelling of engineering products and realisation of computer-based environment for product development. 2001.
15. **Toivo Tähemaa**. Assurance of synergy and competitive dependability at non-safety-critical mechatronics systems design. 2002.
16. **Jüri Resev**. Virtual differential as torque distribution control unit in automotive propulsion systems. 2002.
17. **Toomas Pihl**. Powder coatings for abrasive wear. 2002.
18. **Sergei Letunovitš**. Tribology of fine-grained cermets. 2003.
19. **Tatyana Karaulova**. Development of the modelling tool for the analysis of the production process and its entities for the SME. 2004.
20. **Grigori Nekrassov**. Development of an intelligent integrated environment for computer. 2004.
21. **Sergei Zimakov**. Novel wear resistant WC-based thermal sprayed coatings. 2004.
22. **Irina Preis**. Fatigue performance and mechanical reliability of cemented carbides. 2004.
23. **Medhat Hussainov**. Effect of solid particles on turbulence of gas in two-phase flows. 2005.

24. **Frid Kaljas**. Synergy-based approach to design of the interdisciplinary systems. 2005.

25. **Dmitri Neshumayev**. Experimental and numerical investigation of combined heat transfer enhancement technique in gas-heated channels. 2005.

26. **Renno Veinthal**. Characterization and modelling of erosion wear of powder composite materials and coatings. 2005.

27. **Sergei Tisler**. Deposition of solid particles from aerosol flow in laminar flat-plate boundary layer. 2006.

28. **Tauno Otto**. Models for monitoring of technological processes and production systems. 2006.

29. **Maksim Antonov**. Assessment of cermets performance in aggressive media. 2006.

30. **Tatjana Barashkova**. Research of the effect of correlation at the measurement of alternating voltage. 2006.

31. **Jaan Kers**. Recycling of composite plastics. 2006.

32. **Raivo Sell**. Model based mechatronic systems modeling methodology in conceptual design stage. 2007.

33. **Hans Rämmal**. Experimental methods for sound propagation studies in automotive duct systems. 2007.

34. **Meelis Pohlak**. Rapid prototyping of sheet metal components with incremental sheet forming technology. 2007.

35. **Priidu Peetsalu**. Microstructural aspects of thermal sprayed WC-Co coatings and Ni-Cr coated steels. 2007.

36. **Lauri Kollo**. Sinter/HIP technology of TiC-based cermets. 2007.

37. **Andrei Dedov**. Assessment of metal condition and remaining life of in-service power plant components operating at high temperature. 2007.

38. **Fjodor Sergejev**. Investigation of the fatigue mechanics aspects of PM hardmetals and cermets. 2007.

39. **Eduard Ševtšenko**. Intelligent decision support system for the network of collaborative SME-s. 2007.

40. **Rünno Lumiste**. Networks and innovation in machinery and electronics industry and enterprises (Estonian case studies). 2008.

41. **Kristo Karjust**. Integrated product development and production technology of large composite plastic products. 2008.

42. **Mart Saarna**. Fatigue characteristics of PM steels. 2008.

43. **Eduard Kimmari**. Exothermically synthesized B_4C-Al composites for dry sliding. 2008.

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45. **Tiit Hindreus**. Synergy-based approach to quality assurance. 2009.

46. **Karl Raba**. Uncertainty focused product improvement models. 2009.

47. **Riho Tarbe**. Abrasive impact wear: tester, wear and grindability studies. 2009.

48. **Kristjan Juhani**. Reactive sintered chromium and titanium carbide- based cermets. 2009

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52. **Andres Petritšenko**. Vibration of ladder frames. 2010.

53. **Renee Joost**. Novel methods for hardmetal production and recycling. 2010.

54. **Andre Gregor**. Hard PVD coatings for tooling. 2010.

55. **Tõnu Roosaar**. Wear performance of WC- and TiC-based ceramic-metallic composites. 2010.

56. **Alina Sivitski**. Sliding wear of PVD hard coatings: fatigue and measurement aspects. 2010.

57. **Sergei Kramanenko.** Fractal approach for multiple project management in manufacturing enterprises. 2010.