M.Sc. Thesis

EIT InnoEnergy – SELECT
Environomical Pathways for Sustainable Energy Systems

Development of a combined-cycle cogeneration power plant model with focus on heat-electricity decoupling methods

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Abstract

The energy system is rapidly changing in all aspects, and also renewable energy is integrated on a large scale to the grid in recent years. Renewable energy provides advantages in decarbonising energy system, energy security and also improving energy access. It is certain that renewable energy brings benefits, but also brings operational challenges to the energy system. Variability in the renewable energy resource asks for larger flexibility to compensate the losses and balance the system as a whole. In future, some of the conventional generators which have characteristics like highly efficient, low specific emissions are highly desirable in providing flexibility at large scale.

In this study, a combined cycle cogeneration power plant is chosen, and flexibility improvements using heat-electricity decoupling methods are analyzed. A techno-economic analysis of a combined cycle cogeneration power plant is conducted using DYESOPT (DYnamic System OPTimizer) tool, to compare power plant performance in different operational conditions. The öresundverket power plant located in Malmö, Sweden is considered as a reference power plant to develop a simulation model.

Annual performance of the power plant is analyzed at three different modes of operation namely full condensation mode, design alpha value with constant DH demand and a varying DH demand modeled using statistical data. Technical, economic and environmental performance indicators are used to analyze the performance. One of the drawbacks is that power plant does not have provision to take advantage of energy prices in both electricity and district heating markets, i.e. excess electricity is produced at decreased heat generation in the cogeneration power plant.

A hot water accumulator of 500 MWh capacity is considered as a heat-electricity decoupling strategy to overcome the drawback and also to improve flexibility. Two weeks of power plant operation with storage system improved economics by 12,800 USD. It is found that combined operation of the power plant with thermal storage has provided better operational flexibility for power plant operation in electricity and district heating market.

Keywords: Combined-cycle, cogeneration, levelized cost of electricity, district heating.

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Glossary

CCGT	Combined cycle gas turbine
CHP	Combined heat and power
DH	District heating
VRE	Variable renewable energy
GT	Gas turbine
ST	Steam turbine
TRNSYS	Transient system simulation tool
LHV	Lower heating value
HRSG	Heat recovery steam generator
HPT	High pressure turbine
IPT	Intermediate pressure turbine
LPT	Low pressure turbine
CAPEX	Capital expenditure
OPEX	Operational expenditure
LCOE	Levelized cost of electricity
DYESOPT	Dynamic Energy System OPTimizer
TIT	Turbine inlet temperature
E	Electrical energy
Q	Thermal energy
η	Efficiency
x	Fraction or specific quantity
P	Pressure
T	Temperature
$\mathcal{M}$	Mass flow rate
NTU	Number of transfer units
$\mathcal{E}$	Effectiveness
h	Enthalpy
C_p	Specific heat capacity
Wh	Watt hour
Kg	Kilogram
KJ	Kilojoule

1. Introduction

Renewable energy has become a significant growing component of the energy system in recent years. The major driving factors for this increased growth are in achieving energy system decarbonisation, long-term energy security, and increased energy access to new consumers. Hydroelectricity, by far accounted for the largest contributor in the energy mix. Biomass, wind and solar are finding its way through strong research & development by bringing down the costs. Trends in integration of renewables [1] to electricity system for different regions is shown in Figure 1.1. It is an undeniable fact that renewable energy brings advantages to the energy system and environment compared to the usage of fossil fuel powered systems. It is important to investigate the challenges that grid could face in the future by integrating renewable energy in large scale. The challenges that energy system could face in the future and possible solutions are briefly discussed in this study.

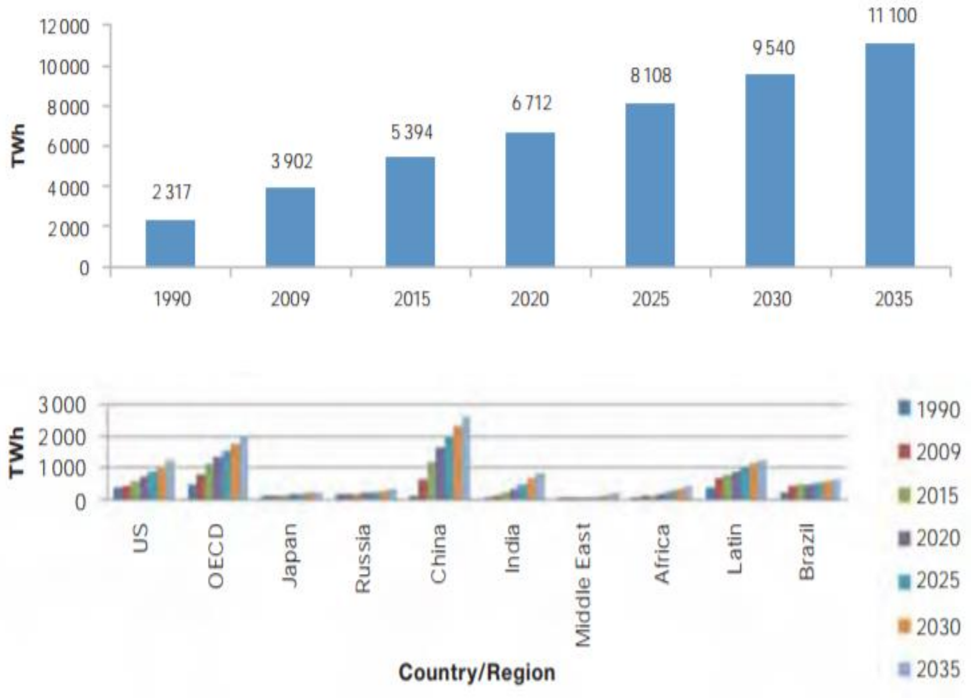

Figure 1.1 Trends in renewable energy integration
Image source: World Energy Outlook, 2011

1.1 Increased VRE generation in the energy system

Most of the power grids all over the world are dominated by conventional power plants powered by fossil fuels. They are reliable in providing energy supply to grid and mature in terms of technology. But over the last century, burning of fossil fuels like coal and gas has increased atmospheric carbon dioxide (CO_2) concentration in the atmosphere, causing increased greenhouse effect, climate change effects. These power plants have brought serious environmental damages to the world, and renewable energy is needed in large scale to decarbonize the system. In recent years, solar power and wind power are becoming more profitable in terms of operation and rate of return on investment. The mix of renewables is expected to improve and growth expectations according to IEA new policy scenarios [1] are shown in Figure1.2.

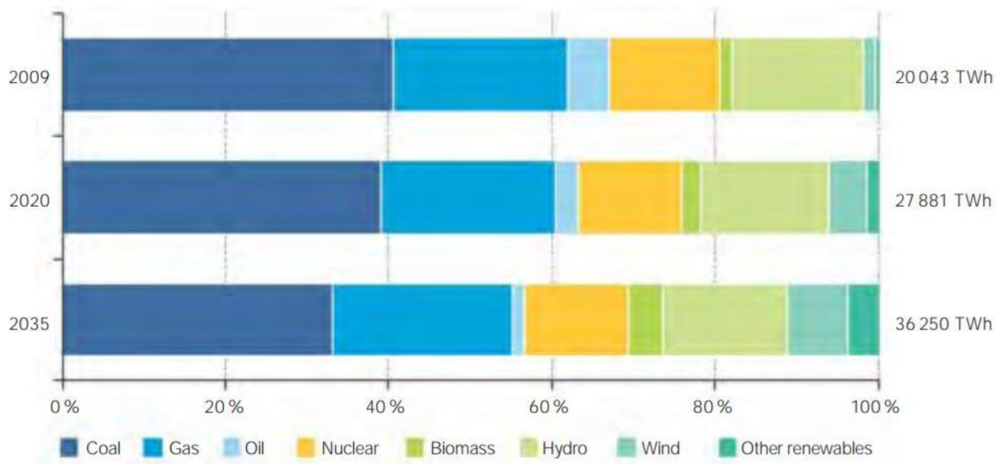

Figure 1.2. Share of electricity generation by fuels in IEA new policy scenarios
Image source: World Energy Outlook, 2011

The grid infrastructures aren't built to deal with variable energy systems at a larger scale which has intermittent resources. By doing so, operational difficulties are created and making it difficult to maintain balance in the grid. Solar and wind energy, which represents a larger share in new integrations experience troubles like intermittency, a combination of non-controllable variability and partial unpredictability, and they are also location-dependent systems [2]. Highly accurate forecast of renewable energy resources can make integration of VRE at large scale possible and still small level of uncertainty in the model could bring serious issues in the balance of the system during a contingency. Some of the common disadvantages associated with VRE resources are,

Non-Controllable variability

It is of prime importance that demand and generation should be same at any instant to maintain the frequency of the grid. Failing to maintain may lead to blackout and severe economic loss. The output from renewable energy system varies in a way that generators cannot control beyond a certain extent because resources are intermittent and this directly affects output. When connected to the grid, this fluctuation in power output results in the need for additional energy to balance supply and demand on an instantaneous basis until the operations returns to normal predicted output.

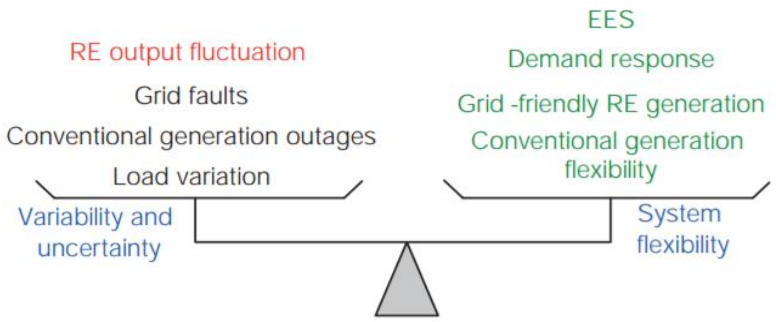

Figure 1.3 Balance between uncertainty and flexibility in energy system

Partial unpredictability

Partial unpredictability also called as uncertainty and is different from variability. The chances that forecaster power output varies from actual power generation might not be in the tolerance level at most situations. This situation is likely to happen even multiple forecast scenarios are made. Unpredictability factor can be managed through improved forecasts and maintenance of flexible reserves in standby to provide support when RE generation fall/rise compared to predicted output.

Location dependence

Different regions in the world have different climatic conditions and enriched with different energy resources. Places with good renewable resources are usually far the community areas.

New infrastructure has to be considered before building new power plants and benefits have to be calculated carefully. Also, the technical need arises to manage the issues in the variable RE systems regarding the transmission technology to be used. Cost-benefit analysis plays an important role in decision making for setting up generation systems far from the living area.

From the Figure 1.3 and the discussion above [2], we can see that integrating large scale renewable energy system to power grid brings variability, uncertainty and there is a need for flexibility to compensate them. RE power plants generate electricity in a quite similar way like any other conventional power plants, though generated power has quite distinctive characteristics in a generation, transmission, operational technology and understanding these characteristics provide the basis for integrating large-capacity RE power in the grid. Some solutions for providing system flexibility are developing improved dispatch strategies, load management, provision of ancillary services, and expansion of transmission capacity, utilization of energy storage, flexible reserve and linking dispatch planning with resource forecasts. It might take the calculated amount of time to develop cost efficient storage and demand response in large scale. So, Conventional generation flexibility is one of the promising solutions and more importantly cleaner, and efficient conventional generation systems are more important in achieving environmental goals as well.

1.2 Improved flexibility from conventional generation

Conventional generators are very mature regarding technology and can provide power on demand. At the same time, conventional generators are the main reason for increased concentration of carbon dioxide in the atmosphere. So, conventional generators which are the most fuel efficient, low specific CO_2 emissions should be preferred for providing flexibility. Technical characteristics of conventional generation plants that explain operational flexibility are cycling, ramping and partial loading capabilities.

- Cycling capability refers to the ability to frequent, fast start-up and shutdown of power plants.
- Ramping capability refer to the rate at which generator can change its output, either upwards or downwards.
- Partial loading capability refers to the minimum output level at which generator can

be stably operated.

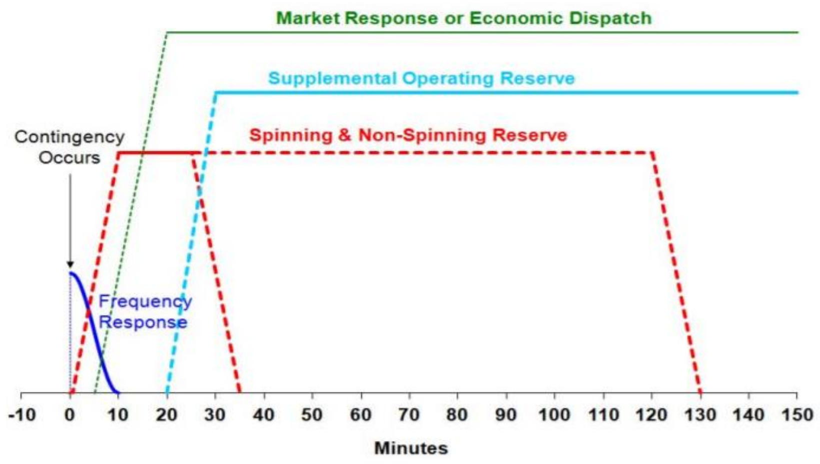

Figure 1.4 Response rates of different generation systems during contingency

Whenever contingency occurs in the system, different generators are called upon to provide support depend on the duration of the issue and power plants ability to support. Response rate for different generators are shown in Figure 1.4. Thermal power plants operated by steam turbine, gas turbine or hydro power come under spinning reserves category. Due to difference in design and technology, different system offers different level of flexibility in accordance with varying impacts on system health, service life, operational costs and GHG emissions. Gas turbine systems are most promising energy systems to provide high level of flexibility in very short span of time. Most popular solution to date is open cycle gas turbines (OCGT), which is very responsive, expensive and generate high emissions per kWh. New advanced combined cycle power plants (CCGT) can provide flexibility on par with OCGT plants and has high energy efficiency comparing OCGT. Electrical efficiency of the CCGT power plants is in range of 50 – 60%, which is more than 1.5 times electrical efficiency of conventional coal power plants. Also cogeneration – combined generation of heat and electricity are known to be highly fuel efficient. In this study, flexibility options of a combined cycle cogeneration power plant are analysed by conducting a techno-economic analysis. A brief explanation of combined cycle and cogeneration process is given below and justification on why this kind of power plants can play an important role in future energy system is also made.

1.3 Combined cycle Power Plant

The basic principle of combined cycle power plant is to operate one or more gas turbine (topping cycle) in cascade, followed by the Rankine steam cycle (bottoming cycle) with same fuel source [3]. The heat source of steam cycle is exhaust of operating gas turbine and the exhaust gas is recovered in heat recovery steam generator to produce steam at specified conditions to expand in steam turbine. Heat recovery steam generator is commonly called as recovery boiler. Total efficiency of combined cycle can reach up to 55% and are able to surpass that value with most advanced bottoming cycle configurations. In combined cycle, gas turbine provides two-third of the total capacity and the steam cycle provides rest of plant's capacity. Above explained operation of combined cycle power plant is explained with a simple layout in Figure 1.5.

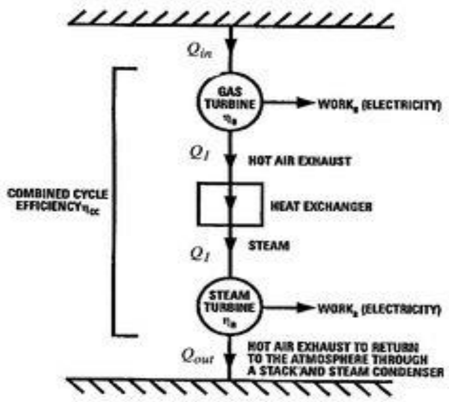

Figure 1.5 Layout describing combined cycle power generation system

1.3.1 Topping Cycle - Gas Turbine

Gas turbine cycle in CCGT plants works on close approximation to theoretical Brayton cycle and comprises of three main components, a compressor, a turbine-expander and a combustion chamber for heat source. Fuel is burnt in the combustion chamber to provide energy to the compressed gas. The hot gas is then expanded through the turbine, providing mechanical energy to a rotating shaft connected to alternator. Part of the power generated in the turbine expander is used to drive the compressor and this creates a limiting factor for gas turbine to achieve higher electrical efficiency.

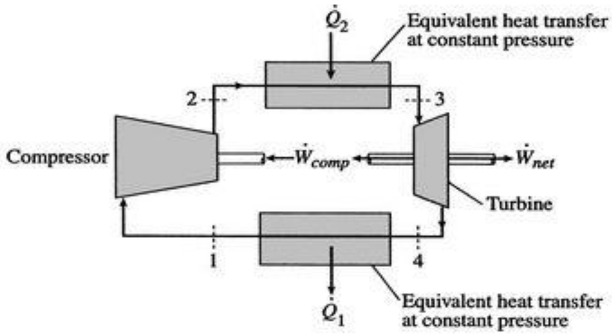

Figure 1.6 Layout describing power gas turbine power generation systems

The process starts from ambient conditions (state 1), air being drawn through series of filters to remove solid particles and compressed to higher pressure (state 2). Energy produced in combustion chamber is exchanged to the compressed air at constant pressure conditions (state 2 to state 3). Then, hot gas is expanded to ambient conditions as explained in Figure 1.6. Mass flow of fuel in combustion chamber is influenced by desired turbine inlet temperature (TIT).

1.3.2 Bottoming Cycle - Steam turbine with recovery boiler

Rankine bottoming cycle improves the heat recovery efficiency of the combined system by utilizing waste energy available in exhaust gas of gas turbine. Rankine cycle usually operates in two or three pressure stages with reheat or regenerative heating system.

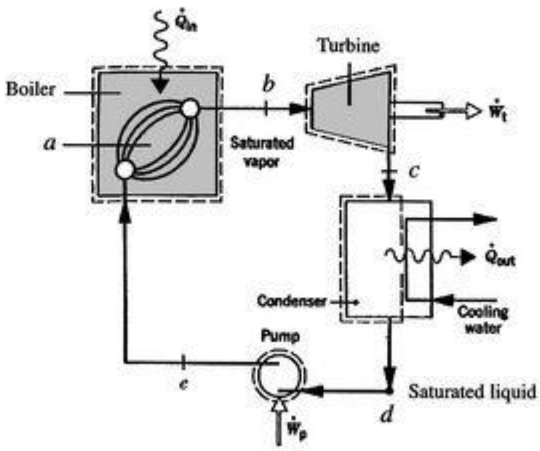

Figure 1.7 Layout describing steam turbine power generation systems

For each stage, boiler comprises of economizer to raise working fluid conditions to evaporator level, evaporator to boil the fluid to steam conditions and super heater to raise steam conditions towards desired turbine inlet conditions. Rankine reheating is a process, where the steam flows back to boiler after isentropic expansion in high pressure turbine stage and heated till it reaches superheated conditions. Superheated steam is then expanded in intermediate stage turbine and then low pressure stage follows in a similar way as intermediate stage. Reheating in Rankine cycle is mainly done to decrease the moisture content of working fluid and also this step significantly improves the Rankine cycle efficiency. Simple working of steam cycle in a single pressure stage with a boiler, turbine and condensing system is explained in Figure 1.7.

1.3.3 Cogeneration systems

Cogeneration or combined heat and power (CHP) is combined generation of electrical energy and useful heat at the same time. On contrary with conventional power plants, which releases waste heat to environment by condensing, CHP plants capture waste heat to supply process heat to industries or district heating network as hot water [4]. This improves the overall efficiency of power plant more than 80%. In this study, a combined cycle cogeneration power plant is considered and CCGT CHP systems have high electrical efficiency, low specific emissions and at same time can operate with overall efficiency higher than 80%.

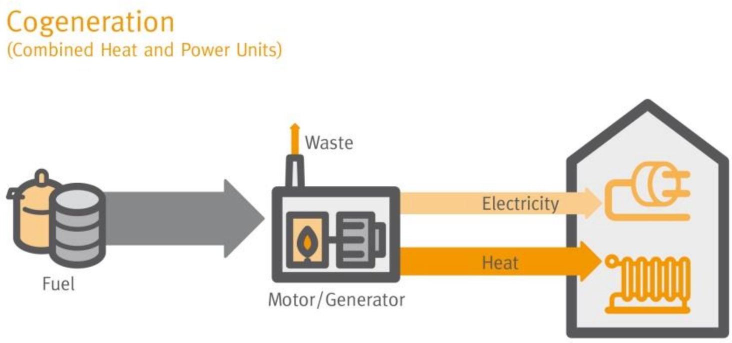

Figure 1.8 Layout describing cogeneration process

Figure 1.8 describes cogeneration process, the generator produces both electricity and heat at same time utilizing same quantity of fuel. Same fuel is used to generated heat and electricity and it is of importance to understand the relation between heat and electricity generation in cogeneration system. Figure 1.9 indicates the relation between electrical efficiency and thermal efficiency in a simple cogeneration process.

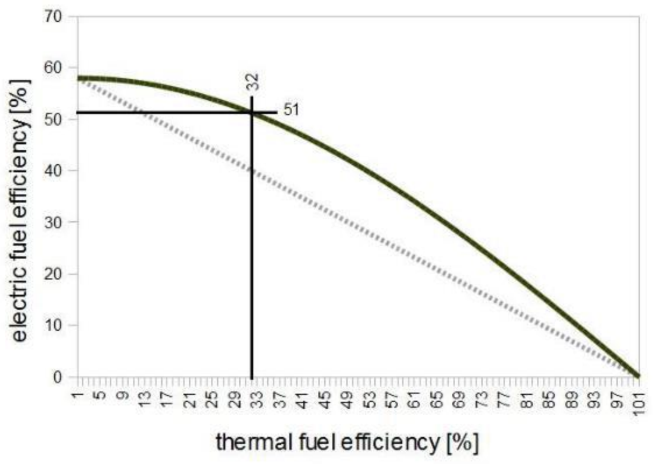

Figure 1.9 Relation between electrical and thermal efficiency in a cogeneration process

The electric efficiency of the system decreases by generating more useful heat from cogeneration system but at the same time, the energetic output of heat generation is considerably greater than the loss in electricity production as shown in the Figure 1.9. The relation can be seen that increasing one product generation is done at cost of losing other product.

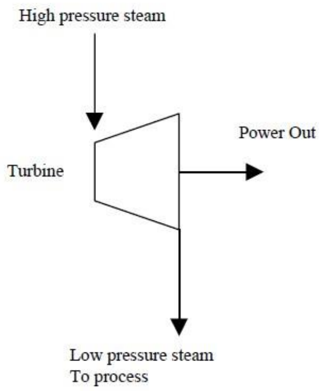

Figure 1.10 Layout describing back-pressure turbines

For example, there is a strong relation between electricity and heat generation in cogeneration power plants configured with back-pressure turbines. Back-pressure turbine, a type of turbine that is used in connection with industrial processes where there is a need for low or medium pressure steam. High pressure steam from boiler is expanded in back-pressure turbine and leaves at a pressure normally higher than the atmospheric pressure. This directly reduces electrical efficiency of the system for not expanding at lower pressure and creates strong linear relation between output products. So, decoupling both heat and electricity generation in the cogeneration system will help in improving the flexibility of operation. In the following section, two of possible solutions for decoupling heat-electricity is discussed.

1.3.4 Flexibility in cogeneration power plants

Cogeneration power plants are designed with either back pressure or extraction-condensation steam turbines. The major drawback with back pressure turbine is that both electricity and thermal energy generation are coupled in a way that district heating supply strongly influences electrical generation in the plant. Two ways to decouple heat and electricity generation in combined cycle power plants are extraction-condensing turbines and utilizing thermal energy storage system. The benefits and flexibility improvements from these two solutions are briefly discussed here,

Extraction – condensing turbine

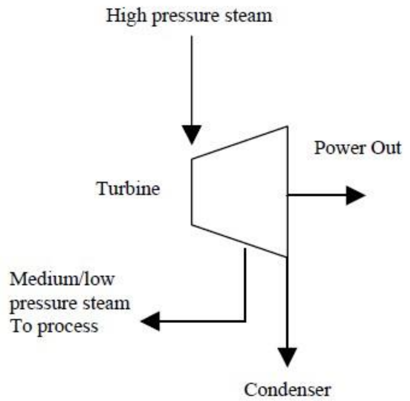

Figure 1.11 Layout describing extraction-condensing steam turbine

In extraction-condensing turbine, a portion of the live steam at some intermediate pressure is extracted for process purpose and rest of the steam is condensed below atmospheric pressure in a condenser. Unlike back-pressure turbine, extraction-condensing turbine has less influence between generation of both products and still can operate with high electrical efficiency i.e. steam condensed below atmospheric pressure.

CHP plants with extraction-condensing turbine have more flexibility in participating in both electricity and district heating markets compared to power plants with back pressure turbine. If the operator decides to run in maximum electricity generation, this can be done by curtailing heat generation. It is possible for operator to choose between maximizing electricity or heat generation depending on market prices, but cannot maximize production of both products at the same time.

Thermal Storage

Thermal storage can be charged during low DH demand, low electricity price hours and dispatch storage during periods of peak electricity hours to improve power plant earnings. In this way, power plants with base load operation in DH market can maximize both products at the same time.

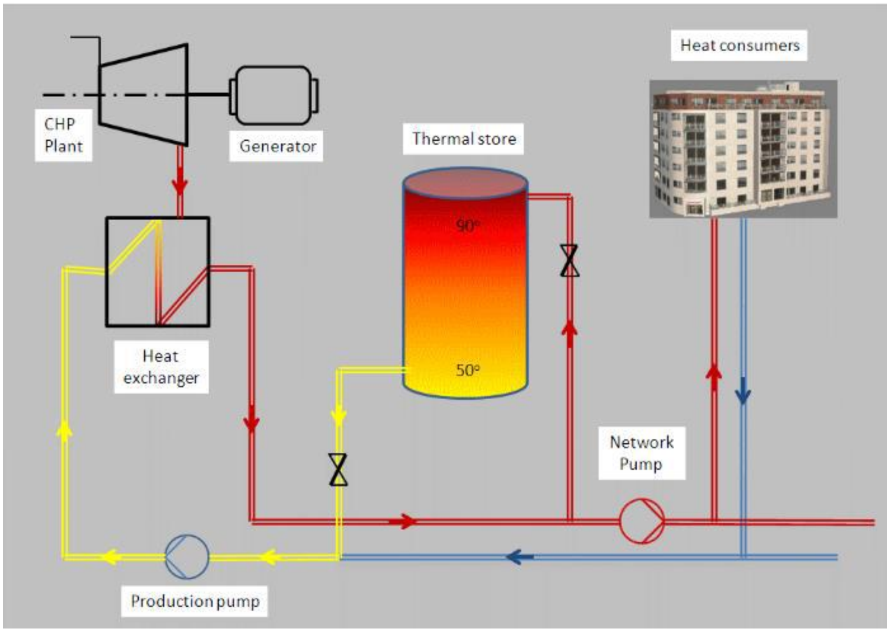

Figure 1.12 Layout describing operation of CHP with thermal storage system

Some of the characteristic advantages are, thermal storage is found to be one of the cost-effective ways to improve performance of the cogeneration power plant and can be utilized to,

- To decouple electricity and heat production
- To operate generation units in most fuel efficient load
- Provide flexibility in operational planning
- Improved availability to participate in providing ancillary services in energy market

It can be seen from the above discussion, decoupling heat-electricity generation will enable highly efficient cogeneration systems to improve flexibility in operation and play an important role in future energy systems.

1.4 CHP and District heating in Sweden

District heating in Sweden has a long history and infrastructure are traditionally built, owned and managed by municipalities. First such system was built in 1948 at Karlstad, Sweden. DH succeeded in Sweden because of lack of competition from natural gas, introduction of climate change policy measures and also climatic conditions in Sweden made district heating profitable. District heating has large initial investment costs and the economic benefits can be seen in long term operation of the network.

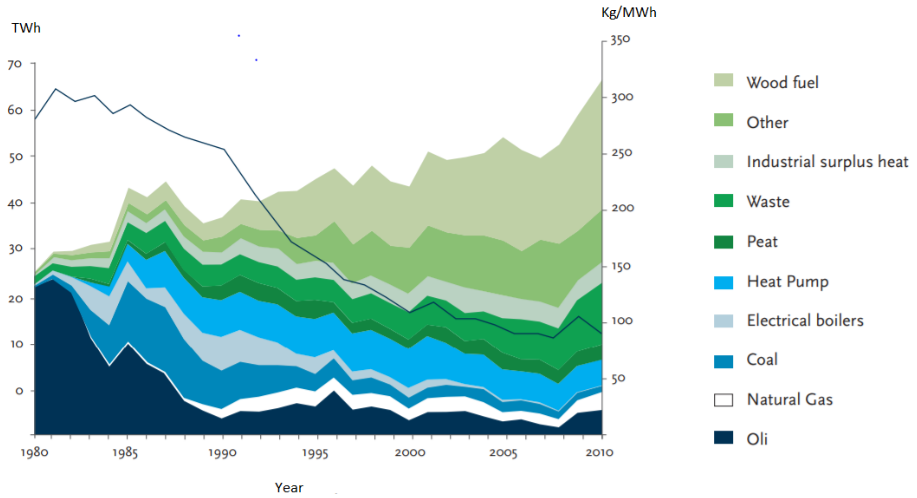

Figure 1.13 Share of Energy source in Sweden district heating

It has to be noticed that CHP systems were not preferred traditionally in Sweden due to low electricity prices from hydropower generation, nuclear power. Nowadays, CHP is an important part of sustainable energy system as it has higher fuel efficiency and plays a major role in bringing down emissions associated with heating supply. Also transition to more environment friendly fuel insisted in Sweden's policies indirectly supported CHP systems.

Another policy measure that greatly influenced DH sector in Sweden was green electricity certificate system. This policy supported vast CHP expansion in Sweden. In 2010, 61.8 % of electricity generators receiving green certificates were produced by biomass-fuelled CHP plants. DH is integrated into electricity market through cogeneration operation of the power plants and DH market in Sweden was transformed in the same year when the Swedish electricity market is deregulated, 1996. Instead of cost-recovery basis, DH is now sold at market prices similar to electricity market.

Figure 1.13 shows the energy mix in Sweden's district heating system and also demand trend over years [5]. It can be seen that demand was increased until 2000 and demand remained static with minimum change [6]. However, the winter of 2009-2010 was colder than those of previous years, so consumption increased to 68.3 and 60.2 TWh respectively. The static demand in the DH system is due to energy-efficient buildings, response from strict energy policies, and competition from other heating systems. Looking into the future, CHP plants must have flexibility to operate between both markets considering the trend. Also, DH demand in Sweden is expected to decrease during the period of 2030 – 2050 for the same reasons mentioned above and share of DH from renewable sources and use of excess heat from industries are expected to increase in the system [7].

1.5 Scope and methodology of the project

From the above discussed topics, it is clear that energy system is significantly changing and there is a need for flexibility to compensate the imbalance introduced by renewable energy. Combined cycle cogeneration (CCGT CHP) power plants are one such systems and in this study, flexibility improvements of these kind of power plants are analysed. So the main scope of the study is to conduct a techno-economic analysis of the CCGT CHP power plant and investigate the benefits on integrating a thermal storage system. Öresundsverket power plant, located in Malmö, Sweden is considered as a reference power plant for modelling and simulations. Öresundsverket is a natural gas combined cycle cogeneration power plant (1 GT cycle + 1 triple pressure reheat ST cycle+2 DH condensers), which supplies 70% of electricity and 40% of heating needs in Malmö region.

This study is divided in four parts namely,

- Modelling and simulation of power plant model with thermal storage in DYESOPT tool.
- Analyzing annual performance of the power plant without storage system.
- Comparing economic benefits on integrating thermal storage to the power plant.
- Sensitivity analysis

Modelling of the power plant includes steady state design to calculate nominal operation conditions, economic design of the power plant. For simulation, a transient model of the power plant is developed in TRNSYS to conduct annual simulation. And techno-economic calculations are made to present key performance indicators.

2. Techno-economic analysis

Techno-economic analysis is a well-established modelling process, developed in a way considering technology, environmental factors and also ensuring market-driven prices are achieved. Techno-economic analysis in principle is a cost-benefit comparison and these analyses are used to check the economic feasibility of the project. Modelling and evaluating the performance of an energy system completely based on technical considerations may result in solutions which aren't economically viable and at the same time, designing energy systems solely based on cost may result solutions with poor technical performance and can possibly cause increased emissions.

For this study, CCGT CHP power plant model is developed in a techno-economic energy system modelling and analysis tool called DYESOPT (Dynamic Energy System OPtimizer), developed by solar research department in KTH Royal Institute of Technology, Sweden.

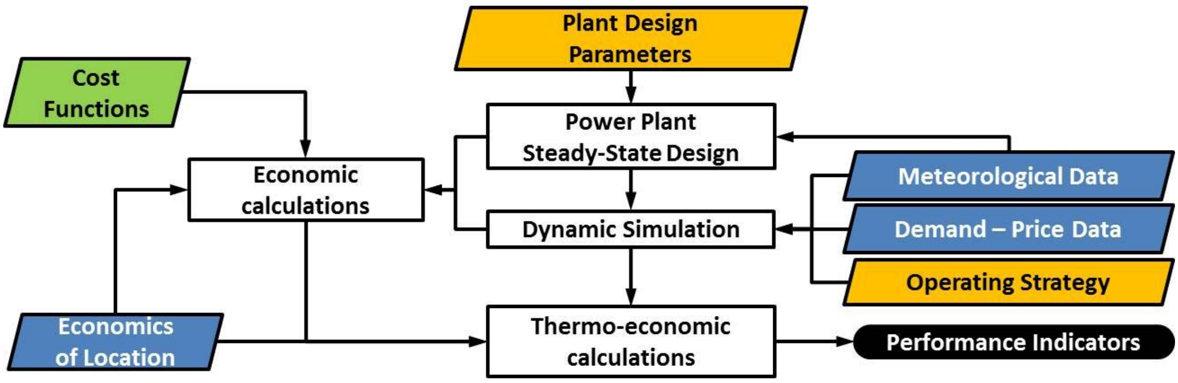

Figure 2.1 Process layout of DYESOPT tool

DYSEOPT is capable of plant design, performance evaluation and economic design of power plants [10]. This tool works between MATLAB and TRNSYS platform, where steady state design, economic design is made in MATLAB, while transient simulations are carried out in TRNSYS platform. Depending on the requirements of the analysis, information is sent from MATLAB to TRNSYS and vice-versa. As a result of this work, developed CCGT CHP power plant model is integrated to DYESOPT tool library for further studies. Figure 2.1 describes the working procedure of DYESOPT tool and tool involves steps, Step 1: Setup power plant design parameters and calculate nominal working conditions of the power plant using steady-state design methodology in MATLAB.

Step 2: TRNSYS model of the power plant is simulated for a specified period of time (normally annual) using meteorological, demand-price and other inputs required.

Step 3: Economic design of the power plant is made in MATLAB which includes capital expenditure, operation and maintenance costs of the power plant.

Step 4: With outputs from annual simulation and economic design, thermo-economic calculations are made and results are provided in terms of key performance indicators.

3. Key Performance Indicators

Key performance indicator is a quantifiable measure used to evaluate the performance of the energy system. In this section, three types of indicators namely technical, economic and environmental performance indicators are used to evaluate performance of CCGT CHP power plant. As the name implies, these indicators reflect the performance of the power plant in each category.

3.1 Technical Performance Indicators

Net electrical output of the power plant refers to total electrical output of the power plant deducting parasitic consumption within the power plant.

$$E_{elec,net} = \int (E_{GT} + E_{ST} - E_{para})dt \tag{3.1}$$

Net thermal energy output of the power plant refers to total thermal energy supplied as hot water to the district network.

$$E_{therm,net} = \int (E_{DH})dt \tag{3.2}$$

Net electrical efficiency refers to ratio of total electrical generation of the power plant to total fuel energy supplied. This indicator shows the quality of power conversion process [8].

$$\eta_{elec} = \frac{E_{elec,net}}{\int (\mathcal{M}_{fuel} * LHV_{fuel})dt} \tag{3.3}$$

Net thermal efficiency refers to ratio of total thermal energy as hot water supplied by power plant to total fuel energy supplied over the year.

$$\eta_{therm} = \frac{E_{therm,net}}{\int (\mathcal{M}_{fuel} * LHV_{fuel})dt} \tag{3.4}$$

Net plant efficiency refers to total efficiency by adding electrical and thermal efficiency of the power plant. This indicator is very useful in estimating the cogeneration operation in the power plant, which will be discusses later in section 4.2.3.

$$\eta_{plant} = \eta_{elec} + \eta_{therm} \tag{3.5}$$

Heat rate of the power plant refers to the factor indicating quantity of fuel required to produce one kWh of electricity and it is inverse of net electrical efficiency calculated in equation (3.3).

$$Heat\ rate = \frac{3600}{\eta_{elec}} \tag{3.6}$$

3.2 Economic Performance Indicators

Specific investment cost refers to investment cost required per kW_{elec} capacity of the power plant. This indicator is often used to compare different power plant in different sizes.

$$C_{specific.inv} = \frac{C_{inv}}{E_{nom,plant}} \tag{3.7}$$

Levelized cost of electricity refers to average minimum cost at which electricity must be sold in order to break-even the spending over the lifetime of the project.

$$LCOE = \frac{\alpha * C_{inv} + \beta * C_{decom} + C_{oper} + C_{maint} + C_{labour} - heat\ credit * E_{therm,net}}{E_{elec,net}} \tag{3.8}$$

$$\alpha = \frac{(1+i)^{n_{cons}} - 1}{n_{cons} * i} * \frac{i * (1+i)^{n_{oper}}}{(1+i)^{n_{oper}} - 1} + k_{ins} \tag{3.9}$$

$$\beta = \frac{(1+i)^{n_{dec}} - 1}{i * n_{dec} * (1+i)^{n_{dec} - 1}} * \frac{i}{(1+i)^{n_{oper}} - 1} \tag{3.10}$$

Cost of electricity generation refers to an estimate to generate electricity, obtained by deducting value of district heating supplied from total running costs of the power plant.

$$Cost_{elec,gen} = Cost_{running\ cost} - Cost_{DH,value} \tag{3.11}$$

3.3 Environmental Performance Indicators

Specific carbon dioxide emissions refer to the carbon dioxide emissions per unit of electricity or thermal energy generated. In cogenerated operation, emissions associated with heat and electricity is calculated by allocating fuel to different products.

$$x_{co_2} = \frac{Net\ co_2\ emissions}{E_{net}} \tag{3.12}$$

Specific water consumption refers to quantity of water consumed by power plant to produce one unit of electrical output.

$$x_{water} = \frac{Vol_{H_2O}}{E_{elec,net}} \tag{3.13}$$

4. Modelling and simulation of CCGT CHP system

In this section, technical and economic design of the CCGT CHP power plant, thermal storage using steady state design calculations and transient model of the power plant (TRNSYS model) is discussed.

4.1 CCGT CHP power plant layout

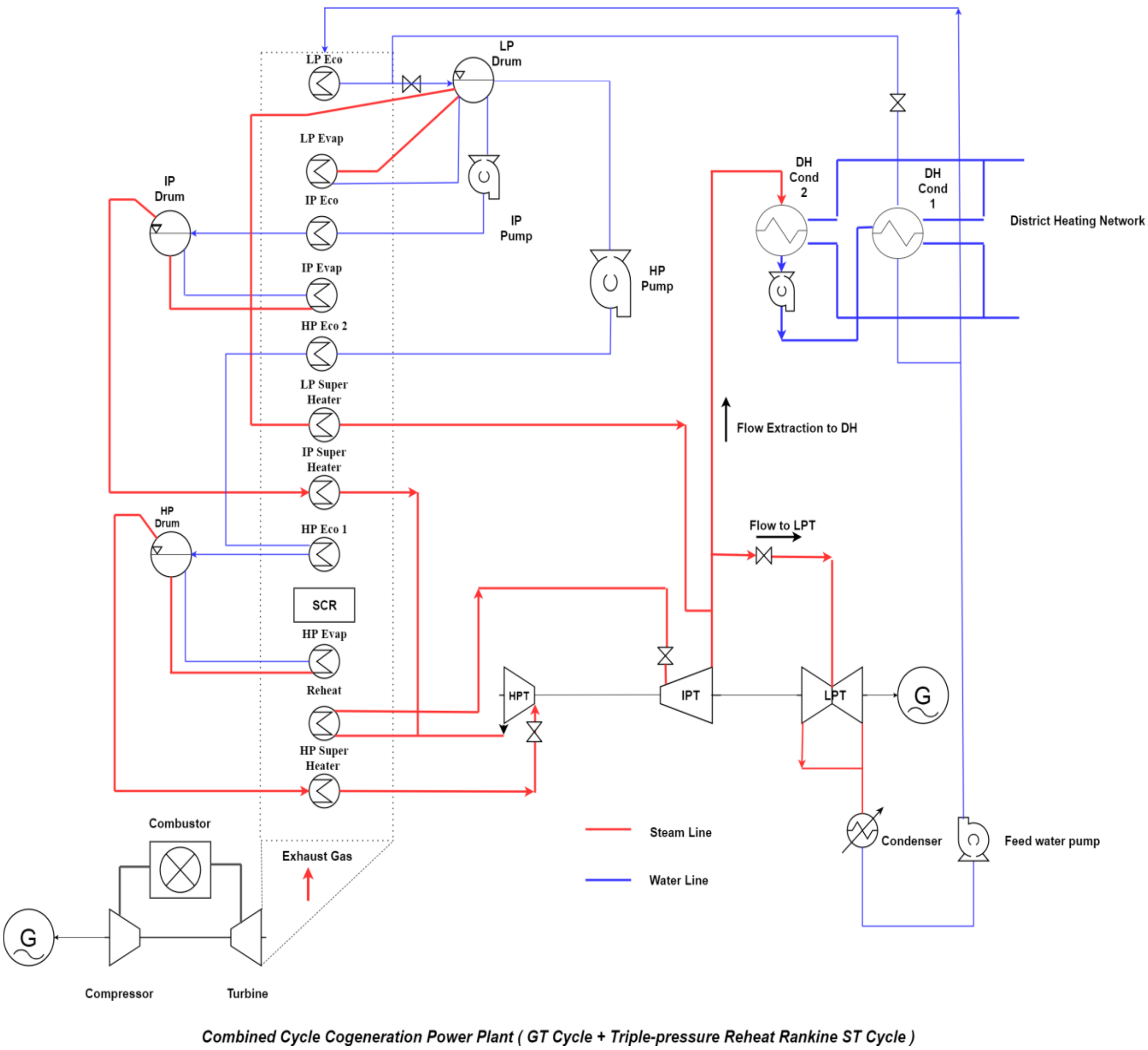

Figure 4.1 Layout describing proposed CCGT cogeneration power plant

The Öresundsverket power plant located in Malmö, Sweden is a natural gas combined cycle cogeneration power plant with one gas turbine cycle, one triple pressure Rankine reheats cycle and two DH condensers. The exact layout of the power plant is shown in Appendix. Due to unavailability of real operational data, a simplified form of power plant is modelled in this study as shown in Figure 4.1. As it can be seen, power plant contains one gas turbine cycle with its exhaust coupled to a heat recovery steam generator, powering steam turbine cycle with three pressure stages and a reheat process. For supplying hot water, a steam extraction point before inlet of low pressure turbine stage is used. Further design parameters and calculation of nominal operating conditions are discussed in below sections,

4.2 Steady state design

4.2.1 Gas turbine cycle – Topping cycle

Steady state design of gas turbine model is made to calculate thermodynamic states (temperature, pressure, enthalpy, etc.,) and mass flows involved in the gas turbine cycle. Proposed GT cycle model consists of four main components such as compressor, combustion chamber, turbine and generator.

Desired design parameters of the plant are shown in Table 4.1 and calculation of operating conditions follows. Ambient conditions from ISO standard for gas-turbine performance [9], namely 15 °C, 1.013 bar at sea level and 60% relative humidity were used to calculate operating points. Detailed explanation on calculation of steady state parameters of the power cycle can be referred from literature [10].

In compressor, inlet pressure is slightly lesser than intake ambient pressure due to losses in air filtration system ($x_{loss,air\ filter}$) and outlet pressure of the compressor can be calculated using assumed compression ratio (Π_{comp}) as shown in equation (4.1) and (4.2). Also, outlet enthalpy of the compression can be calculated by assuming the process to be adiabatic and non-isentropic [11]. Power required by the compressor is calculated based on enthalpy difference as shown in equation (4.3) and (4.4).

Isentropic efficiency used in the above formula is calculated from a relation comprising polytropic efficiency, pressure ratio, gas constant and isobaric specific heat capacity.

Polytropic efficiency of compressor and gas turbine are assumed to be 0.91 and 0.89 according to designed temperature levels [10]. In gas turbine cycle, a certain mass flow of air is extracted from compressor outlet for cooling the turbine blade and also for purging. Mass flow required for cooling turbine blade is influenced by combustion temperature and purge flow is considered as a constant fraction of 3% compressor inlet flow in this model.

Design Parameters	*Value*	
Nominal GT cycle output	*293*	*[MW]*
Nominal compression ratio	*15*	
Combustion temperature	*1500*	*[°C]*
Fuel	*Natural Gas*	
Fuel composition	*Methane [0.85], Ethane [0.10], Propane [0.05]*	
Lower heating value of fuel	*49.5685*	*[MJ/Kg]*

Table 4.1 Design parameters of gas turbine cycle

$$P_{inlet,comp} = P_{atm} * (1 - x_{loss,air\ filter}) \tag{4.1}$$

$$P_{outlet,comp} = P_{inlet,comp} * \pi_{comp} \tag{4.2}$$

$$h_{outlet} = h_{inlet} + \frac{h_{outlet,isen} - h_{inlet}}{\eta_{isen}} \tag{4.3}$$

$$E_{comp} = \frac{\mathcal{M}_{inlet} * (h_{outlet} - h_{inlet})}{\eta_{mec}} \tag{4.4}$$

In combustion model, the nominal fuel mass flow required to power turbine, compressor and composition of outlet gases are determined. Assumptions taken in the model are, complete combustion takes place inside the chamber, no thermal losses to environment and moisture content in the combustion air is negligible. The relative mass flow of fuel required to bring air mass flow to desired combustor outlet temperature is calculated using enthalpy variations in the air, lower heating value of the fuel as shown in equation (4.5).

$$m_{fuel} = \frac{\Delta h_{air}}{LHV_{fuel} - \Delta h_{fuel}} = \frac{\mathcal{M}_{fuel}}{\mathcal{M}_{air,main}} \tag{4.5}$$

Total mass flow from the combustor is sum of inlet compressed air flow and fuel mass flow input to combustion chamber as given by equation (4.6),

$$\mathcal{M}_{comb,out} = \mathcal{M}_{air,main} + \mathcal{M}_{fuel} \tag{4.6}$$

$\mathcal{M}_{air,main}$, refers to the mass flow of compressed air. With calculated mass flow, composition of the exhaust gases is calculated according to stoichiometric balance equations shown in (4.7). Since natural gas is considered as fuel source, main focus is to calculate carbon dioxide emissions from exhaust gases of GT cycle. Carbon content in the exhaust gas is calculated using equation (4.8)

$$C_xH_y + \left(1 + x + \frac{y}{4}\right)O_2 \longrightarrow xCO_2 + \frac{y}{2}H_2O \tag{4.7}$$

$$x_{C,fuel} = \frac{12x}{12x+y} \tag{4.8}$$

In turbine model, power extracted from GT cycle and thermodynamic states of exhaust gases are calculated. Turbine inlet temperature (TIT) is calculated from an energy balance equation between exhaust gases from combustion and cooling flow extracted from outlet of compressor. Outlet pressure of the turbine is calculated using equation (4.9), where x_{dp} is relative pressure drop factor of exhaust duct and silencer of GT cycle.

$$P_{exhaust} = \frac{P_{outlet,comb}}{(1 - x_{dp})} \tag{4.9}$$

Turbine expansion process is considered adiabatic, non-isentropic process [11] similar to compression. Shaft power of the GT turbine can be calculated using equation (4.10)

$$E_{turbine} = \eta_{mec} * \mathcal{M}_{comb,out} * [\, h_{inlet} - \left(h_{inlet} - \eta_{isen}\left(h_{inlet} - h_{outet,isen}\right)\right) \,] \tag{4.10}$$

The net electrical output of the GT cycle is calculated using equation (4.11) considering electrical and mechanical efficiency and subtracting compressor power.

$$E_{elec,out} = \eta_{mec}\, \eta_{elec}\, (E_{turbine} - E_{comp}) \tag{4.11}$$

Using design parameters of the GT cycle, nominal operating conditions of the cycle is calculated and selected parameters will be useful in steady state design of bottoming cycle.

Nominal operating points	*Value*	
Fuel flow rate	*15.80*	*[Kg/s]*
Fuel power	*783.30*	*[MJ/s]*
Turbine inlet temperature - TIT	*1281*	*[°C]*
GT cycle exhaust temperature	*621.46*	*[°C]*
GT cycle exhaust mass flow	*686.98*	*[Kg/s]*
Nominal cycle efficiency	*37.41*	*[%]*
Nominal GT cycle output	*284.21*	*[MW]*

Table 4.2 Nominal operating conditions of gas turbine cycle

4.2.2 Steam turbine cycle – Bottoming cycle

Exhaust gas from the GT cycle is coupled with a heat recovery steam generator, commonly called as recovery boiler to complete the bottoming cycle. In this section, boiler design, power generation in ST cycle at each stage and steam extraction for DH condensers calculation are shown.

Heat Recovery Steam Generator

In this section, flow rates in high pressure, intermediate pressure and low pressure section of boiler for a given flow of GT turbine exhaust gas is calculated. Thermodynamic states of exhaust gas calculated in section 4.2.1 are used as an input for this section. Design parameters for ST cycle are shown in table 4.3.

Assumptions used for HRSG model are, heat losses from exchanger to environment is negligible and no mixing between hot and cold stream fluids in heat exchangers.

Effectiveness NTU method and pinch point analysis [12] are used to calculate the mass flow rate from evaporator and heat exchanger areas. The pinch point diagram for triple-pressure Rankine reheat cycle is shown in Figure 4.2. Outlet temperature of exhaust gas from HRSG is fixed as 71 °C.

Design Parameters	***Value***	
HP stage pressure	*140*	*[bar]*
IP stage pressure	*24*	*[bar]*
LP stage pressure	*5.2*	*[bar]*
HPT inlet temperature	*566*	*[°C]*
IPT inlet temperature	*566*	*[°C]*
LPT inlet temperature	*312*	*[°C]*
Condenser temperature	*30*	*[°C]*

Table 4.3 Design parameters for ST cycle

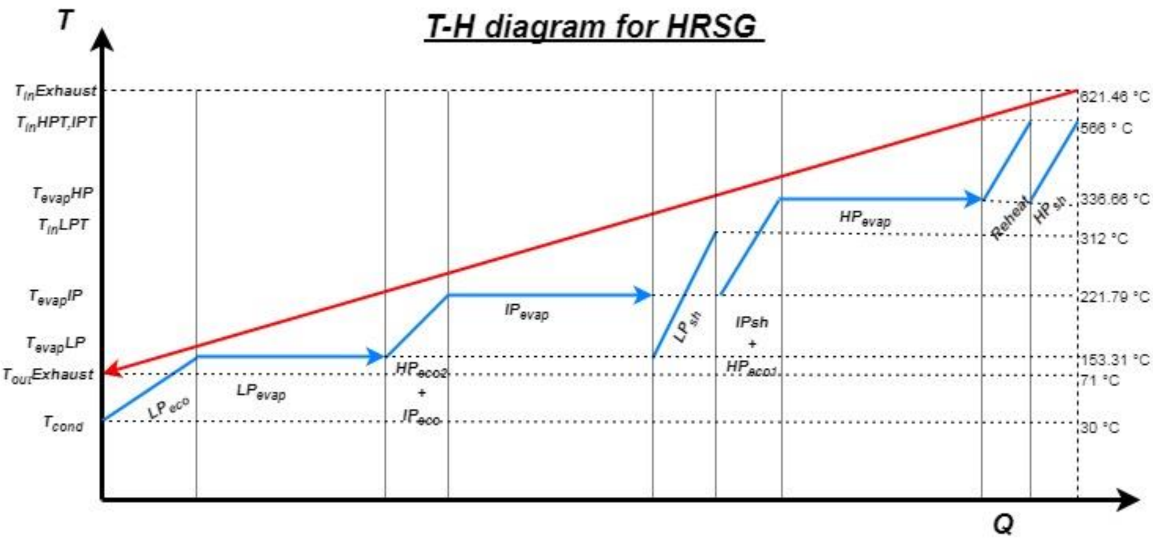

Figure 4.2 Pinch diagram of heat recovery steam generator

Hot stream (flue gas) from exhaust of GT cycle enters in one side of HRSG and cold stream (water) from feed water pump flows in other side of HRSG at condenser temperature. Flow rate of high pressure section is calculated as a function of gas turbine exhaust flow rate, flow rate in reheat section and enthalpy variations in each heat exchanger section as shown in equation (4.12). Enthalpy variation in gas section is calculated using temperature difference in the heat exchangers considering minimum approach temperatures of different streams.

$$\mathcal{M}_{HP,steam} \quad \frac{\mathcal{M}_{exhaust}\Delta h_{gas,HP} - \mathcal{M}_{reheat}\Delta h_{reheat}}{\Delta h_{HP,sh} + \Delta h_{HP,evap}} \tag{4.12}$$

Similar to equation (4.12), mass flow rate in intermediate pressure and low pressure sections are calculated using functions of enthalpy variations, mass flow of exhaust gas and enthalpy variation of exhaust gas in those respective sections. Mass flow rate in the reheating section is shown in equation (4.13).

$$\mathcal{M}_{reheat} = \mathcal{M}_{HP} + \mathcal{M}_{IP} \tag{4.13}$$

As it can be noticed, mass flow in reheat section is not known at the point of solving equation (4.12). Initial guess for mass flow in reheat section is made and flow rate equations of all three pressure sections are solved iteratively to calculate mass flow rates at each sections.

System Parameters	***Obtained Value***	
HPT live steam flow	*73.49*	*[Kg/s]*
IP flow from evaporator	*21.18*	*[Kg/s]*
IPT live steam flow	*94.67*	*[Kg/s]*
LP flow from evaporator	*12.49*	*[Kg/s]*
LPT live steam flow	*107.17*	*[Kg/s]*
HPT power output	*32*	*[MW]*
IPT power output	*40*	*[MW]*
LPT power output	*88*	*[MW]*
Net ST power output	*160*	*[MW]*

Table 4.4 Nominal operating conditions of ST cycle in full condensation mode

Surface areas of heat exchangers are required in economic design of the power plant, section (4.3) and it is calculated using effectiveness-NTU method knowing mass flow rate in each pressure section. Approach temperature ($\Delta T_{min}/2$) values of high pressure gases, low-pressure gases, evaporating water, condensing water are 15, 20, 2 and 2 (°C) respectively [10]. Total minimum approach temperature in heat exchanger with two streams is calculated by adding $\Delta T_{min}/2$ values of each stream that flows across exchanger.

$$\varepsilon = 1 - \frac{\Delta T_{min,approach}}{\Delta T_{hx}} \tag{4.14}$$

$$NTU = \frac{UA}{C_{min}} \tag{4.15}$$

$$C_r = \frac{C_{min}}{C_{max}} \tag{4.16}$$

For economiser and super heater sections of HRSG, cross flow heat exchanger is assumed and number of transfer units (NTU) is calculated using equation (4.17) and for evaporator section, equation (4.18) is used.

$$NTU = -\ln\left[1 + \left(\frac{1}{C_r}\right)\ln(1 - \varepsilon C_r)\right] \tag{4.17}$$

$$NTU = -\ln(1 - \varepsilon) \tag{4.18}$$

With number of transfer units, heat exchanger surface areas can be calculated using equation (4.15). Where UA is overall heat transfer coefficient of heat exchangers considering heat transfer coefficient of hot, cold streams and thickness, thermal conductivity of heat exchanger walls [10].

Steam Turbine and feed water pump

In this section, power extracted from expansion of steam at different pressure levels is calculated and thermodynamic states of exhaust steam in the ST cycle are calculated. Turbine expansion is considered adiabatic, non-isentropic [11] and is calculated using equation (4.19).

$$h_{outlet} = h_{inlet} - \eta_{isen} * (h_{inlet} - h_{outlet,isen}) \tag{4.19}$$

Inlet enthalpy at high pressure is the live steam conditions and for intermediate- pressure low-pressure section, exhaust from turbine stage and live steam from super heater is mixed as shown in Figure (4.1). Knowing enthalpy and mass flow across ST turbine, shaft power of each turbine is calculated using equation (4.20).

$$E_{ST} = \eta_{mec} * \mathcal{M}_{steam} * (h_{inlet} - h_{outlet}) \tag{4.20}$$

Since extraction-condensing turbine is considered in the power plant model, surface condenser is designed with water as coolant [12]. Area of the surface condenser is calculated in a similar way as heat exchangers using equations (4.14 - 4.18).

Feed water pump is required to pump the water from condenser pressure to desired pressure levels at each pressure stage of boiler and the power required for each pump is calculated with a function of pressure difference as shown in equation (4.21). Water required for surface condenser with vacuum deaerator is calculated using enthalpy variation across the condenser and maximum temperature rise allowed in the water side as shown in equation (4.22). 10 °C temperature rise for water in the condenser is considered in this study.

$$E_{pump} = \frac{\mathcal{M}_{water}}{\eta_{hydraulic}} \left(\frac{\Delta P}{\rho}\right) \tag{4.21}$$

$$\mathcal{M}_{conden} = \frac{\mathcal{M}_{steam} \Delta h_{conden}}{c_{p,water} * (\Delta T_{rise,conden})} \tag{4.22}$$

In the steam cycle design, nominal operation conditions of the boiler and steam turbines are calculated and nominal output of each turbine stage is also calculated.

District heating condensers

District heating part of the CCGT power plant contains two condensers that supply hot water to district heating network to fulfil heating demands as shown in Figure 4.1. DH condenser 2 is a two-phase condenser (hot stream – steam, cold stream – water) and DH condenser 1 is a single phase (hot, cold side – water) condenser. The maximum and minimum DH demand that power plant can supply is 408 MW (with ST cycle off) and 25 MW (with full ST cycle production). Operation scenarios of the power plant at different DH demand level is briefly explained in the following section 4.2.4. Steam extraction from ST cycle depends on the DH demand from 25 – 250 MW and this directly influences LPT ST cycle generation proportionally from 160 – 115 MW. In the following section, different modes of operation of power plant is represented with alpha value (α) of the CHP power plant, which refers to ratio of electric power generated to thermal power supplied as shown in equation (4.23).

$$\alpha = \frac{P_{elec}}{P_{therm}} \tag{4.23}$$

Steam extracted is passed to DH condenser 2 to exchange heat as it is condensed to saturated liquid at lower pressure. Condensed water from DH condenser 2 is pumped again to higher pressure and mixed with flow from LP economizer to exchange remaining energy in DH condenser 1 until hot stream of the exchanger reaches condenser temperature at LP pressure conditions. After DH condenser 2, hot stream mixes with feed water from LP pump to enter HRSG as shown in Figure 4.1. Steam extraction for DH demand at any moment is calculated using an energy balance across the DH condensers and energy in steam flow as shown in equation (4.24). Areas of both condensers are calculated in a similar way as heat exchangers using equations (4.14 - 4.18).

$$\mathcal{M}_{steam,LP}\Delta h_{steam,LP} = E_{dh} + E_{LPT} - E_{LP,eco,dh} \tag{4.24}$$

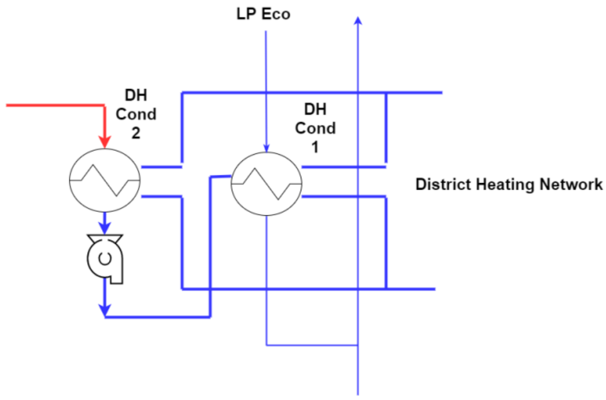

Figure 4.3 Layout of DH condenser system

DH system requires other parameters namely, supply temperature, return temperature and DH demand. Supply temperature of the DH demand is influenced by the DH demand, i.e. higher supply temperature is required to compensate higher DH demand and maintain the mass flow in the network. Return temperature of the DH system depends on the network performance and consumption behaviour.

For simplification, supply and return temperatures of the DH system are modelled as a function of ambient temperature [13].

$$E_{dh} = \mathcal{M}_{flow}C_p(T_{supply} - T_{return}) \tag{4.25}$$

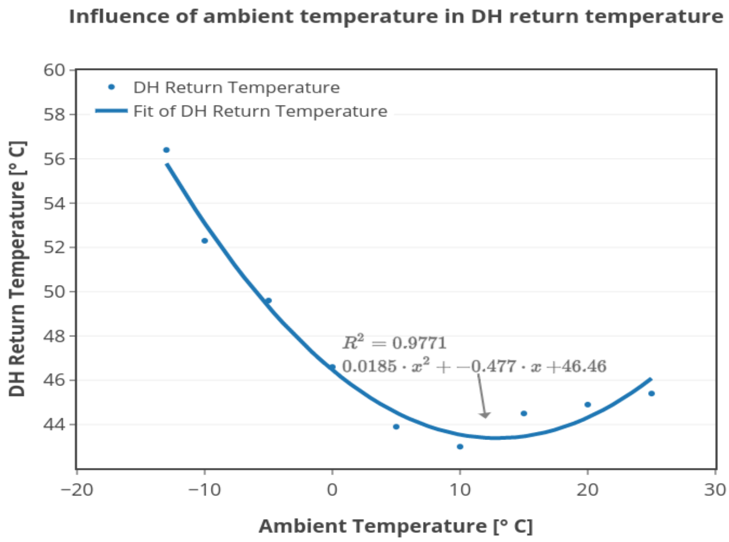

Figure 4.4 DH return temperature as a function of ambient temperature

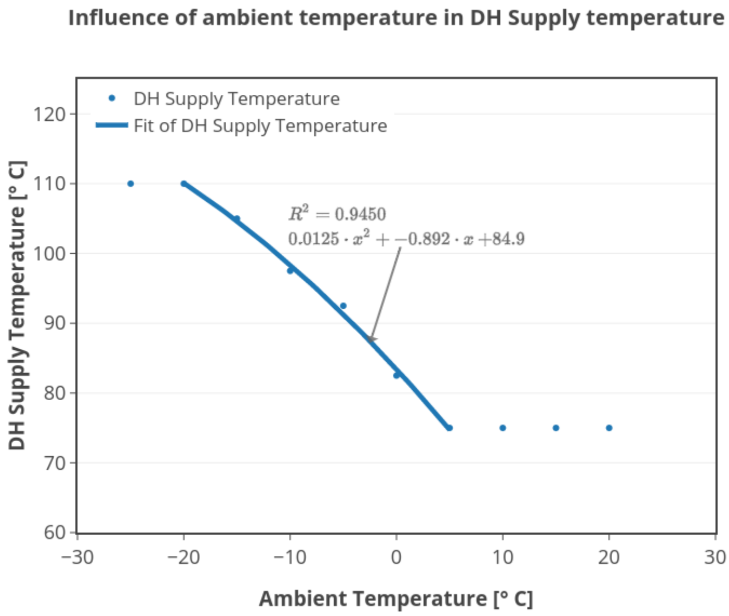

Figure 4.5 DH supply temperature as a function of ambient temperature

Influence of ambient temperature in supply, return temperature can be seen in Figure (4.4) and (4.5). Modelling of these parameters as input for annual simulation in discussed in the following section. For steady state design, some design parameters considered to calculate operational points are shown in Table 4.5.

System Parameters	*Value*	
Design supply temperature	*90*	*[°C]*
Design return temperature	*45*	*[°C]*
Design DH demand	*408*	*[MW]*
DH Demand from LP economizer	*25*	*[MW]*
Live steam flow before LPT inlet	*107.17*	*[Kg/s]*

Table 4.5 Design parameters of DH system

4.2.3 Combined Cycle cogeneration design and Performance evaluation of cogeneration system

Net electric power output and net heat supply generated from combined cycle cogeneration power plant can be calculated using equation (4.26) and (4.27). Parasitic electricity consumption like feed water pump, condenser pump, DH pumps and other auxiliary usages in the power plant are subtracted from net output.

$$E_{net} = E_{GT} + E_{ST} - E_{para} \tag{4.26}$$

$$Q_{DH} = Q_{DH,cond1} + Q_{DH,cond2} \tag{4.27}$$

Cogeneration performance evaluation, it is necessary to differentiate between energy generation from cogeneration operation and energy generation from non-cogeneration operation. If the net plant efficiency of the power plant is greater than or equal to threshold efficiency of cogeneration operation, then total electricity generation is considered as cogenerated power. If the net plant efficiency is less than threshold efficiency as shown in equation (4.30), cogenerated power is calculated using following steps [14],

$$E_{CHP} = H_{CHP} * C \tag{4.28}$$

$$E_{non-CHP} = E_{net,elec} - E_{CHP} \tag{4.29}$$

Threshold value of total efficiency for power plants with extraction condensing turbine is 80%. In equation (4.28), C is the power to heat ratio. *Power to heat ratio shall mean the ratio between the electricity from cogeneration and useful heat when operating in full cogeneration* *mode using operational data of the specific units.*

If $\eta_{plant} < \eta_{threshold}$, then $\eta_{CHP} = \eta_{threshold}$. (4.30)

Power loss coefficient (β), refers to ratio of loss in electrical power to increase in thermal power production of extraction-condensing unit [15].

$$\beta = \frac{-\Delta E_{plant}}{\Delta H_{CHP}} \quad (4.31)$$

Power to heat ratio is calculated as shown in equation (4.32) for an extraction-condensing turbine unit,

$$C = \frac{\eta_{elec,max} - \beta\eta_{CHP}}{\eta_{CHP} - \eta_{elec,max}} \quad (4.32)$$

With C value, electricity generation from cogeneration is calculated as shown in equation (4.28). It is also important to calculate fuel energy used for the CHP part and non-CHP part as shown in equation (4.33) and (4.34). This will help in calculating taxes for different product from the power plant and will be discussed in section 4.3.2.

$$Fuel_{CHP} = \frac{E_{CHP} + H_{CHP}}{\eta_{CHP}} \quad (4.33)$$

$$Fuel_{non-CHP} = Fuel_{total} - F_{CHP} \quad (4.34)$$

4.2.4 Power Plant Operational Schemes

Power plant's operational schemes are explained in a simple layout as shown in Figure 4.6. When the DH demand rises from 25 – 250 MW, steam extraction from ST cycle is made to compensate the demand and the ST generation falls proportionally from 160 – 115 MW respectively. As one can note, each MW of electrical energy generation in ST cycle is equivalent to 5 MW of thermal energy supplied in DH system. Whenever the DH demand is above 250 MW, ST cycle is shut down and all the energy from the exhaust gas is exchanged in the DH condenser. The minimum amount of DH supply, 25 MW is provided from LP economizer and demand lesser than or equal to 25 MW does not require steam extraction from ST cycle. Some of the common operational modes of CHP plants are described below,

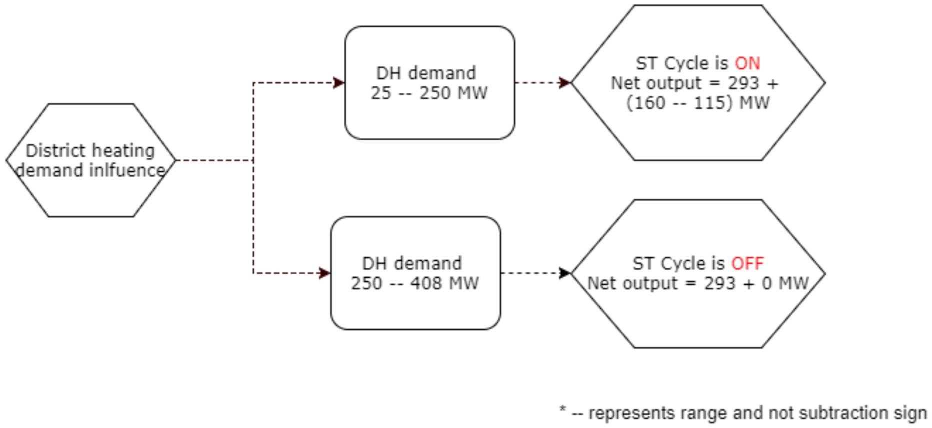

Figure 4.6 Simple layout describing power plant operations at different DH demand level

Three different modes of operation commonly practised in the cogeneration power plants are briefly explained below,

Heat driven mode: Heat driven mode is followed by power plants supplying base loads in district heating network. Normally, waste power plants, biogas power plants with back pressure turbine follow this kind of operating. Power plant operation follows DH load from the network to generate DH as primary product and electricity as secondary product.

Electricity driven mode: Electricity driven mode is adapted by power plants which expects their major income from electricity market and produce district heating supply as by-product. Primary objective of the power plant is to bring economics from the electricity market and produce DH as secondary product.

Market driven mode: Market driven mode is followed by power plants which has flexibility to operate between any of the above two modes and decision on the operating mode is based on market price of the product. When the electricity price is higher compared to DH price, it is more profitable to generate more electricity rather participating in DH market.

Power plants in which heat and electricity generation are decoupled can take advantage by operating in market driven mode. Extraction-condensing steam turbine is one such feature where two products are decoupled.

4.2.5 Thermal Storage Design

A large cylindrical hot water tank over the ground is considered as a thermal storage system for this power plant. Capacity of the storage to compensate DH demand only in duration of hours is considered, i.e. capacity to shift the DH demand in the near future to generate more electricity during peak hours. For this reason, water which has high heat capacity is chosen as storage medium. Thermal storage usually works between two temperature levels to maintain temperature gradient and the two temperatures are namely return temperature and supply temperature from storage system. The maximum and minimum temperature in storage tank is considered constant and values are 100 °C and 45 °C respectively. Storage capacity of 500 MWh is considered for this study as initial capacity.

Thermal losses in the tank is be calculated by separating tank into three main surfaces namely, lateral, top and bottom as shown in equation (4.35). A simple layout describing construction of storage tank is shown in Figure 1.9.

$$Q_{losses} = Q_{top} + Q_{lateral} + Q_{bottom} = (U_t A_t + U_l A_l + U_b A_b)(T_{storage} - T_{amb}) \quad (4.35)$$

$$U_t = \frac{1}{\left(\frac{d_{conc}}{\lambda_{conc}} + \frac{d_{xps}}{\lambda_{xps}} + \frac{1}{h_{conv}}\right)} \quad (4.36)$$

$$U_l = \frac{1}{\left(\frac{d_{conc}}{\lambda_{conc}} + \frac{d_{xps}}{\lambda_{xps}} + \frac{1}{h_{conv}}\right)} \quad (4.37)$$

$$U_b = \frac{2}{R^2} * (\alpha * \left(\frac{\lambda_{gnd}}{\pi}\right)^2 * \ln\left(\frac{a}{a - R * \frac{\pi}{\lambda_{gnd}}}\right) - R * \frac{\lambda_{gnd}}{\pi} + \frac{1}{h_{conv}} \quad (4.38)$$

$$\alpha = R * \frac{\pi}{\lambda_{gnd}} + \frac{d_{conc} + d_{xps}}{\lambda_{gnd}} + \frac{d_{conc}}{\lambda_{conc}} + \frac{d_{xps}}{\lambda_{xps}} \quad (4.39)$$

Parameters assumed to calculate the losses are referred from literature [16]. It is assumed that maximum charge and discharge rates [17] to and from the thermal storage is 50 MWh/h and 100 MWh/h respectively. These constraints in the model are chosen to consider the dynamics of the system.

4.3 Transient Simulation

Performance of the energy system depends on many design parameters that varies throughout the year like atmospheric pressure, temperature, etc., So, analysing energy systems performance only on its nominal state doesn't give results close to real operations. So, a transient simulation of the power plant is performed using a commercial simulation tool, TRNSYS.

TRNSYS, TRaNsient System Simulation tool is a flexible simulation used for simulation of different transient and dynamic systems. In this section, explanation of TRNSYS model, inputs for the simulation and the operational strategy of the power plant and thermal storage will be discussed.

4.3.1 Model Explanation

Transient model of CCGT cogeneration power plant is developed using STEC library [18]. STEC is a collection of TRNSYS models developed to simulate solar thermal power generation. For this study, components from Rankine and Brayton section of STEC library are used.

For Brayton cycle, components namely compressor stage, combustion chamber, turbine stage and a PID controller to control the exhaust gas pressure are used to develop GT cycle TRNSYS model. For Rankine cycle, components namely economiser, evaporator, reheat, heat exchanger for super heater, steam turbine stage, condenser are used to develop ST cycle TRNSYS model. Steam extraction and steam turbine operation controls are implemented in the dynamic model using user-defined equation blocks.

Components from STEC library which are used in this study are validated by comparing with real operation of 30 MW_{elec} solar thermal power plant and errors are usually less than 10%. Flow sheet of GT and ST cycle model is shown in Appendix.

4.3.2 Model Input Data

TRNSYS model of the power plant model requires varying inputs for parameters like atmospheric temperature, pressure for power plant and DH demand, supply and return temperature for DH system. Other parameters of the power plant components are design parameters and nominal operating conditions calculated in section 4.2 for transient simulation. The time step of 1 hour is used for simulation and in total 8760 steps of simulation is chosen in this study.

Inlet air conditions namely, ambient temperature and atmospheric pressure for Malmö region are taken from Swedish Meteorological and Hydrological Institute (SMHI), Swedish open data website [19] producing forecasts of weather, wind, water and climate in Sweden is shown in Figure (4.7). These two inputs are used for simulation of power block in TRNSYS model.

For district heating system, parameters namely supply and return temperature of DH system are to be modelled for TRNSYS simulation. In the section 4.2.2, a relation between ambient temperature and supply, return temperature is shown and this relation is used to model the temperatures. Ambient temperature of Malmö region shown in Figure 4.7 is used to model the supply and return temperature shown in Figure 4.8.

Due to unavailability of DH demand data from Öresundverket power plant, demand is modelled with statistical data of DH supply from one of the CHP plants operated by Fortum Värme [20]. Statistical data of DH supply distributed from a CHP plant, combining network load and network losses are shown in Appendix. Two profiles namely, statistical data on DH demand in relation with ambient temperature and social load on the network during different days are used to model the DH demand shown in Figure 4.9.

Another parameter namely electricity price of Sweden in the year 2015 is taken from Nordpool website [21] and shown in Appendix. This market data represents day-ahead electricity price of Sweden's electricity market and used as a signal for making decisions on operation of the thermal storage system. Meteorological data for the power block and DH system input parameters are modelled in this section and sent as readable text files to TRNSYS model for annual simulation of the power plant model.

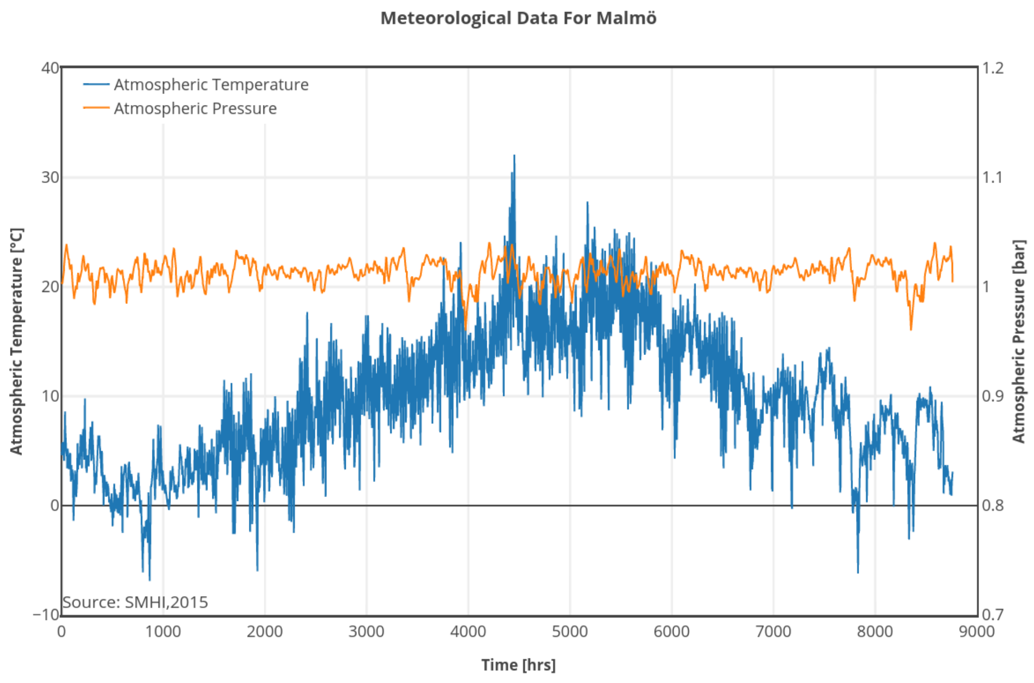

Figure 4.7 Meteorological data for Malmö, 2015

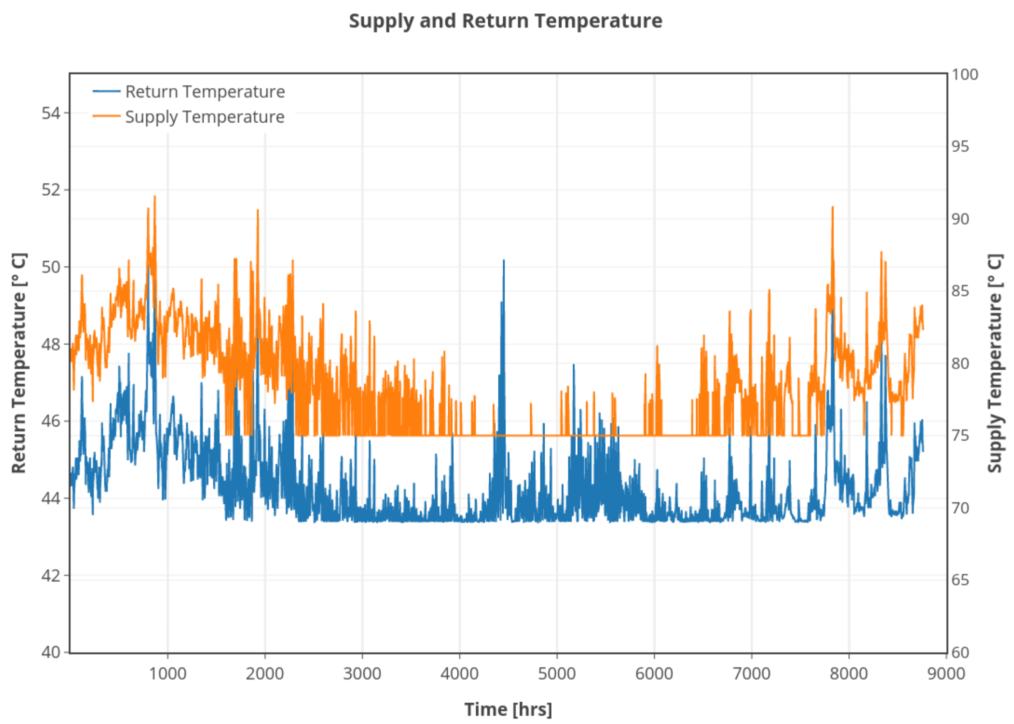

Figure 4.8 Supply and return temperature of DH system

4.3.3 Operational control of Power plant and Thermal storage

Power plant, control operation of the power plant is setup in TRNSYS model using user-defined equation blocks as explained in section 4.2.4. If the DH demand is above 250 MW, steam turbine stage component's bypass control is switched to 0 and when the demand is less than 250 MW, bypass control is switched to 1. In this way steam turbine operation is controlled in accordance with DH demand.

Steam extraction to DH condenser is implemented in the TRNSYS model by creating user-defined equation block with energy balance shown in equation (4.24). These two operational controls are created to reflect real operation of Öresundverket power plant in TRNSYS model. With DH demand, supply and return temperature of the network, mass flow required to supply DH demand is obtained by solving equation (4.25).

Thermal storage integrated into the power plant model requires an operational control to indicate the model when the storage to be charged and when the storage to be discharged. Operational strategy of the storage system is shown in Figure 4.10. Three inputs namely DH demand, electricity price and electricity generation cost curve are required for this control strategy. Electricity generation cost curve is an economic indicator, refers to cost required to generate electricity considering value of DH delivered and only running costs of the power plant. This indicator will be explained after discussing economic design of the power plant in the section 5.3.

Assumptions considered in the power plant operations are,

- Power plant is operated at 100% load at each time step.
- Storage system is used as a buffer to displace the DH production in low peak hours and improve electricity production at peak hours.
- DH demand in the network is always met.

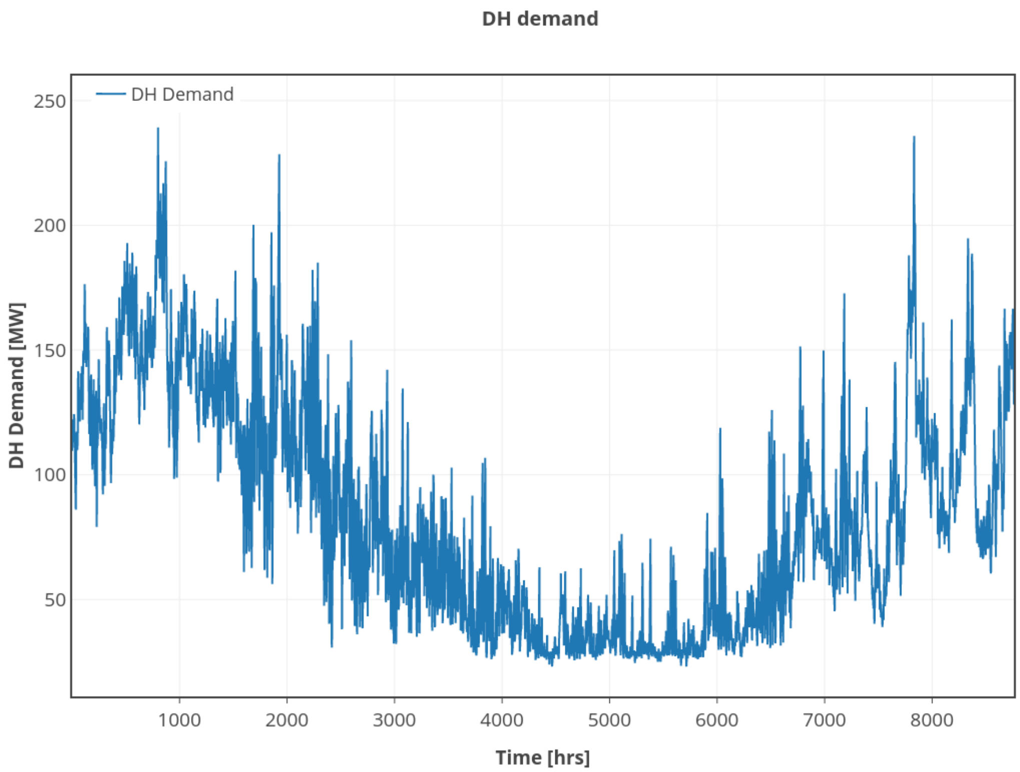

Figure 4.9 Modelled annual DH demand using statistical data

The operational strategy works in a way by designing the storage system first, in this case 500 MWh of thermal storage system is assumed. In the first step, electricity prices for 24 hours is analysed in par with DH prices and a price window where the electricity prices are higher than the DH price is chosen as a dispatch period. During other periods, new optimal DH demand is defined for each hour according to available electricity price. Predicted DH demand is corrected considering the maximum charge rate, energy content of storage system to define a new optimal DH demand point in the power plant. In this way, excess DH energy generated is stored in the thermal storage system and available later for dispatching during the chosen price window. And in the simulation mode, storage losses are calculated during each time step. One important control provided to operation of the power plant is that DH demand is satisfied at all the periods of operations either by generating in power plant or by dispatching available energy in the storage system. In this way a new optimal DH demand file is generated to operate the power plant and benefits are analysed.

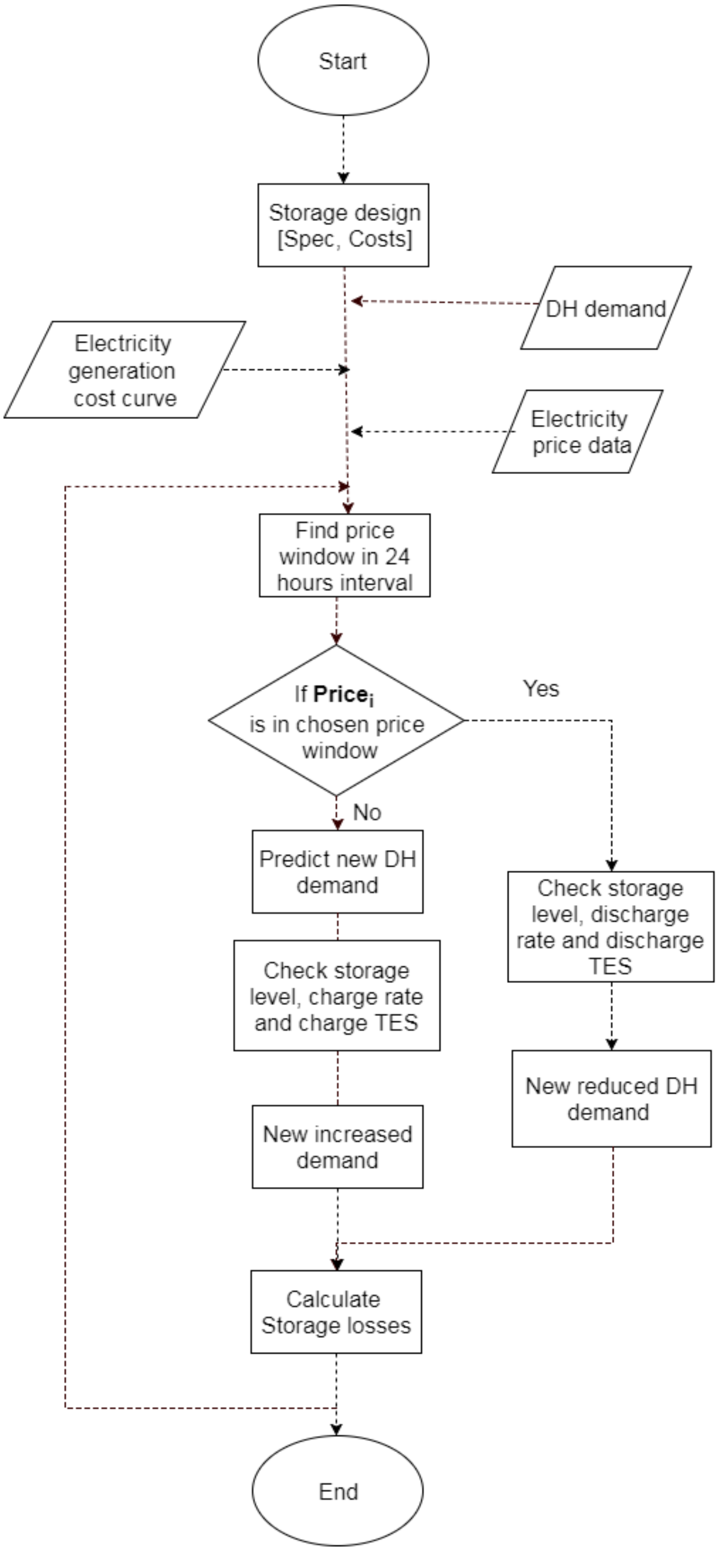

Figure 4.10 Charging and dispatch strategy of hot water storage tank

4.3 Economics of power plant

To compare economic design of different components and fuels, a common base currency for cost comparison is used. In this study all the costs will be stated in USD. Assumed exchange rate between other currencies used in this study to USD is shown in Table 4.6 [21].

Currency	*Exchange rates*
1 USD	*8.435 SEK*
1 EUR	*9.356 SEK*

Table 4.6 Exchange rate of currency in year 2015

Economic design of the power plant includes capital investment cost, operational and maintenance cost, decommissioning cost of the power plant. Detailed economic design of power plant is briefly explained below,

4.3.1 Capital Expenditure Costs (CAPEX)

CAPEX refers to upfront investment costs which include equipment purchasing cost, installation costs, civil engineering costs and other indirect costs associated with the power plant. Sizing and nominal operating conditions calculated in section 4.2 are used to calculate equipment costs of the power plant. Different cost functions are collected to calculate the equipment costs and these functions are dependent on working conditions of different components.

All purchasing costs of the equipment's are scaled by a factor based on Marshall & Swift equipment cost index to consider the effects of inflation of the current year in purchasing cost. The scaling factor $x_{inflation}$, is multiplied with cost functions to scale the purchasing cost to the current year. The scaling factor can be calculated using equation (4.40)

$$x_{inflation} = \frac{I_{M\&S}^{current\ year}}{I_{M\&S}^{reference\ year}} \tag{4.40}$$

$I_{M\&S}^{reference}$ is reference factor for the year the cost-function was established. All the costs are scaled up to year 2015. For the year 2010, Marshall & Swift index is 1477 [22] and the growth of the index until 2015 is found in the article [23]. Index value of the 2015 is used for calculation of equipment costs in this study.

Investment parameters	***Values***	
Interest rate	*6*	*[%]*
Capital insurance rate	*1*	*[%]*
Construction period	*3*	*[years]*
Depreciation period	*25*	*[years]*
Decommission period	*1*	*[year]*
Cost of fuel	*33.19*	$[USD/MWh_{fuel}]$
Cost of water	*2.84*	$[USD/m^3]$

Table 4.6 Parameters considered in economic design of the power plant model

Parameters including construction time, operational years, decommissioning period considered in this study are stated in Table 4.6. Capital investment cost and decommissioning cost of the power plant is calculated using equation (4.41 – 4.49). Cost functions for different components of the power plant are referenced from literature [10] and costs are calculated using the working conditions of the power plant.

For gas turbine components, the purchasing costs are reference from models of Frangopoulos [24] and modification proposed by Pelster [25]. Gas turbine cycle purchasing costs is determined by sum of compressor, turbine, combustion chamber and auxiliary gas turbine components costs as shown in equation 4.41.

$$Cost_{GT} = Cost_{comp} + Cost_{turb} + Cost_{comb} + Cost_{auxiliary} \quad (4.41)$$

Steam turbine cycle purchasing costs is determined by sum of heat recovery generator, steam turbine, surface condenser, DH condenser, water treatment facilities and deaerator components costs as shown in equation (4.42). All the costs are calculated through functions of their operating parameters.

$$Cost_{ST} = Cost_{HRSG} + Cost_{turbine} + Cost_{condenser} + Cost_{DH,condensers} + Cost_{water\ treatment} + Cost_{\ deaerator} \tag{4.42}$$

The total equipment cost of the power plant is calculated by adding gas turbine cycle, steam turbine cycle, generator and power electronic costs as shown in equation (4.43).

$$Cost_{equip} = Cost_{GT} + Cost_{ST} + Cost_{generator} + Cost_{electronic\ cost} \tag{4.43}$$

After purchasing of equipment's, installation costs are calculated by multiplying the equipment costs by a fraction ($x_{install}$), 20% to total equipment costs.

$$Cost_{installation} = x_{install} * Cost_{equip} \tag{4.44}$$

$$Cost_{plant} = Cost_{equip} + Cost_{install} + Cost_{NG,pipe} + Cost_{civil} \tag{4.45}$$

After calculating installation costs, natural gas pipeline and civil engineering costs associated with power plant, total plant expenditure is calculated using equation (4.45). Apart from direct costs like purchasing and installation, CAPEX accounts for contingency, indirect engineering costs and decommissioning costs. These are calculated using equation (4.46 – 4.49) considering $x_{contingency}$, $x_{indirect}$, $x_{decommissioning}$ are 10%, 5%, 5% respectively.

$$Cost_{contingency} = x_{contingency} * Cost_{plant} \tag{4.46}$$

$$Cost_{indirect} = Cost_{contingency} + Cost_{indirect\ engineering} \tag{4.47}$$

$$Cost_{investment} = Cost_{plant} + Cost_{indirect} \tag{4.48}$$

$$Cost_{decommision} = x_{decommission} * Cost_{plant} \tag{4.49}$$

Total investment of the power plant is calculated using equation (4.48) and breakdown of the CAPEX is shown in Figure 4.11.

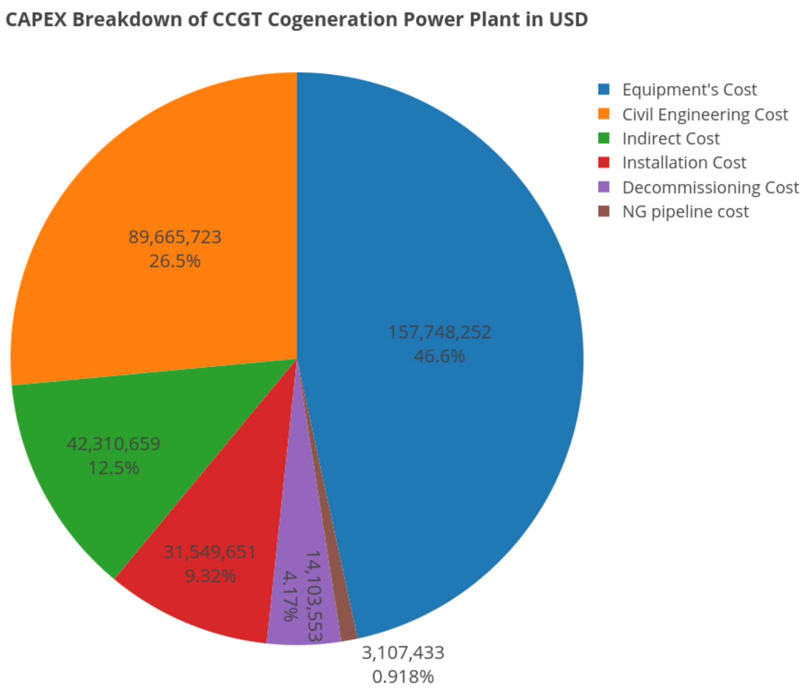

Figure 4.11 CAPEX breakdown of the power plant model

Total investment cost of CCGT CHP power plant shown in equation (4.48) is estimated about 324,381,718 USD.

4.3.2 Operational and Maintenance Expenditure Costs

Unlike one-time CAPEX, operational costs are subjected throughout the operation time of the power plant, i.e. depreciation period. Interest payments of the CAPEX are due each year and annual values of operating costs are determined to calculate total costs annually. For CCGT cogeneration power plant powered by natural gas, the total operating costs is given by equation (4.2), which includes water and fuel costs.

$$Cost_{operational} = Cost_{fuel} + Cost_{water,power\ cycle} \tag{4.50}$$

The cost of the fuel is calculated using equation 4.51 and cost of natural gas is 33.19 USD/MWh$_{fuel}$ [26]. Cost of water is 2.84 USD/m^3 [10].

$$Cost_{fuel} = x_{fuel} \int \mathcal{M}_{fuel} * LHV_{fuel} * dt \tag{4.51}$$

$$Cost_{water,power\ cycle} = x_{water}\left(vol_{water}^{compr} + vol_{water}^{cycle}\right) \tag{4.52}$$

In operation costs, water used in the feed water of the power cycle and compressor washing is considered in operational costs. Water used for condenser is assumed to be supplied from nearby water resource at free of cost with regulated temperature rise levels.

Maintenance costs, wear and tear in the power plants are inevitable and it requires repairs and replacement of components. Some of the damages can be recovered with scheduled preventive maintenance and some damages occur unexpectedly. GT and ST cycle components being very mature, 3% of the component's equipment cost per year is chosen as power block maintenance costs. 4% of investment costs in gas piping and civil engineering elements is chosen as civil maintenance costs for a year [10].

In addition to operational and maintenance costs, labour costs is also necessary to take into consideration. Labour requirement information was obtained from a study by National Renewable Energy Laboratory [27].

$$Cost_{labour} = 803500\ USD/year \tag{4.53}$$

Taxes for CHP systems in Sweden and heat credit

Sweden has energy tax and emission tax in the environmental tax system. Energy tax was introduced during oil crisis to reduce the use of oil and increase the use of electricity. The main aim of the energy tax is to improve the efficiency of energy use, promote bio-fuels, reduce emissions and improve production of electricity. Energy tax is based on the energy content of the fossil fuel and electricity production in Sweden is exempted from energy and CO_2 tax. However, usage of electricity is taxed and this is not a main focus in this study.

Different users namely industries and domestic users pay different energy and CO_2 taxes. However, in CHP plants, fuel used for electricity and heat production is apportioned to calculate taxes. Taxation for different industries and users are shown in Table 4.7 [7]. The reference power plant, Öresundsverket comes under the category of CHP – heat (covered by EU ETS). EU ETS (Emissions Trading Scheme) is governed by Emissions trading directive and has been an important measure to reduce CO_2 emissions in EU region. Particularly in Swedish energy system, all the combustion plants with thermal input larger than 20 MW and all district heating systems where the plant together have a thermal input larger than 20 MW are covered by EU ETS [28].

Type	*Energy tax*	*CO_2 tax*
Heat only (not industry or CHP)	*100 %*	*100 %*
CHP - heat	*30 %*	*60 %*
CHP - heat (covered by EU ETS)	*30 %*	*0*
Electricity	*0*	*0*

Table 4.7 Energy and environmental taxation for different sectors

In the table 4.7, 30% energy tax of CHP-heat user meaningz that 30% of the total energy tax for heat-only production (individual users) is paid. Taxes differ for different fuels and some of them are shown in Table 4.8 [29]. The currency specified in the table is Öre (1 Öre – 0.01 SEK) and it is converted in USD with exchange shown in section 4.3. During cogeneration performance calculations, taxes are allocated to fuel for generation of heat and electricity accordingly.

Fuel type	*Energy tax*	*CO_2 tax*	*Sulphur tax*	*Total tax*	*Tax (Öre/kWh)*
Natural gas (1000/SEK m^3)	*939*	*2409*	*-*	*3348*	*30.3*
Peat (SEK/tonne) (45% moisture,0.3% sulphur)	*-*	*-*	*50*	*50*	*1.8*

Table 4.8 Energy and environment tax for fuel

Heat credit [USD/MWh$_{therm}$], refers to fixed credit for heat, i.e. if cogeneration plant hadn't been built, a heating plant would have been built instead.

In cogeneration power plant, the cost borne is therefore imputed to both electricity and heat generation. The accepted methodology is to calculate electricity generation cost by subtracting an assumed value of heat that is produced, which is calculate using heat credit value. The initial assumed value of heat credit is 28.33 USD/MWh$_{therm}$, which is 239 SEK/MWh$_{therm}$ [30]. However, the real market price of district heating in Sweden is two or three times higher than this price in average.

4.3.3 Investment cost for thermal storage system

In this section, costs associated with installation of thermal storage are discussed. Figure 4.9 shows the costs for the erection of insulated hot water storage steel tank in connection with cogeneration power plants. Cost figures presented in the figure are based on number of tanks over a wide volume range. The cost includes equipment, installation, insulation and auxiliary costs associated with thermal storage system.

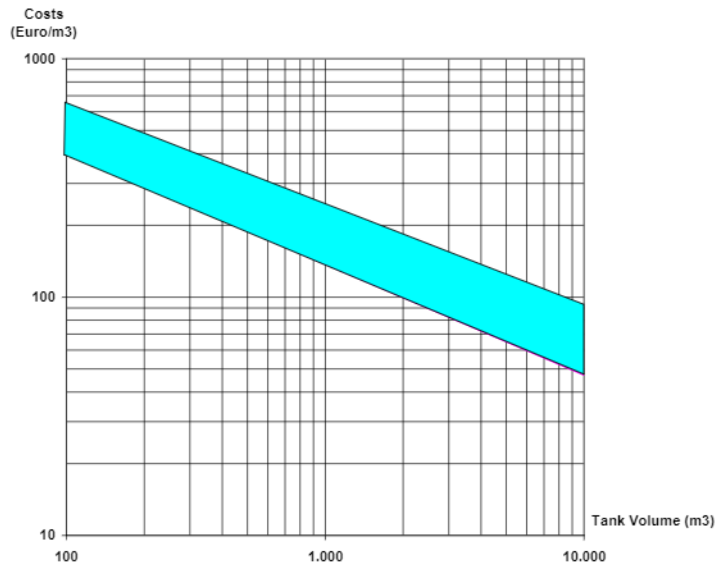

Figure 4.9 Investment cost of insulated heat storage tank including investment costs

The investment cost for 500 MWh of hot water storage tank is calculated using the above relation and estimated as 441,630 USD. The thermal storage system works with power plant as shown in the Figure 1.12. Economic benefits on operation of the power plant with storage system will be analysed in the following section to see if it makes sense to have a thermal storage system in a CHP power plant.

5. Results and Analysis

In this section, annual performance of the power plant is analysed in different modes of operation by calculation and comparing key performance indicators. Annual outputs from TRNSYS model and costs calculated from economic design is combined to calculate key performance indicators discussed in section 3. Also economic benefits in integrating thermal storage system is realized later in this section. This part is divided in to three section for analysing technical performance, economic and environmental performance of the power plant operation without storage and analysis of the power plant with storage system.

5.1 Technical performance of the power plant – No storage operation

Technical performance of the power plant is analysed under different modes of operation to understand how power plant performs at varied mix of electrical and heat generation. Three modes of operation are chosen and explained below,

Mode - (I), Pure condensing mode refers to operation when there is no steam extraction for DH supply and all of the available heat energy is condensed for electric generation. However, during this operation, this power plant can produce a minimum of 25 MW district heating through energy from LP economizer without any influence on electricity generation from ST cycle.

Mode - (II), Heat driven mode refers to operation when the power plant follows the district heating demand in the network. Steam extraction is primarily influenced by DH demand and rest of the steam is condensed for electricity generation. In this mode of operation, supplying DH demand is the major priority and electricity generation is considered as a secondary product. Power plant is simulated to follow DH demand modelled in the section 4.3.2.

Mode - (III), Design alpha value (1.6320) – ((293+115)/205) refers to operation where there is maximum steam extraction from steam cycle for supplying DH demand of 250 MW and rest of the heat is used for electric generation, which corresponds to maximum of 115 MW of electricity generation in steam turbine. This operation mode is considered as optimal operation mode for cogeneration process in the design process of the power plant.

Developed transient model of the power plant is simulated for a year in these three modes of operation with inputs discussed in section 4.3 and performance indicators are shown in Figure 5.1.

Performance indicators	*Mode (I)*	*Mode (II)*	*Mode (III)*
Net ST electrical output [GWh]	*1335.8*	*1226.4*	*960.75*
Net plant electrical output [GWh]	*3815.7*	*3706.3*	*3440.7*
Net thermal energy output [GWh]	*272.25*	*730.85*	*2190.0*
Net electrical efficiency [%]	*58.31*	*56.64*	*52.58*
Net thermal efficiency [%]	*4.16*	*11.17*	*33.47*
Plant efficiency [%]	*62.47*	*67.81*	*86.05*
Heat rate [KJ/KWh]	*6173.6*	*6355.8*	*6848.8*

Table 5.1 Technical performance indicators during three modes of operation

Net plant electrical output is a result of total electrical output from GT cycle, ST cycle and deducting parasitic consumption from total output of two power blocks. Parasitic consumption includes operation of feed water pump, condenser and DH condenser pump. Net plant electrical output of the pure condensing mode is 3815.7 GWh, which is higher than other two operational modes. In pure condensing mode all the available energy in the steam cycle is condensed for maximum electrical generation, which results lowest heat generation only through LP economizer. Net thermal energy output of the plant in design alpha value (III) is 2190 GWh, which is maximum heat generated among three modes of operation. In design alpha value mode, the maximum amount of steam is extracted to supply DH demand while operating the ST cycle at lowest possible load (115 MW) to generate 960.75 GWh.

In operation mode (II), where the power plant follows the DH demand in the Figure 4.9 and produces electricity about 3706.3 GWh, heat energy about 730.85 GWh. In this mode of operation, most of the DH demand is during the winter years which are during the months of August-December, January – March. During other months, DH demand in very low and there is no need for steam extraction to compensate the DH demand and the power plant operates close to pure condensing mode when following the demand.

As one can imagine with electrical generation output of three modes, the net electrical efficiency of the plant is higher in pure condensing mode about 58.31% followed by mode (III) and operation at design alpha value.

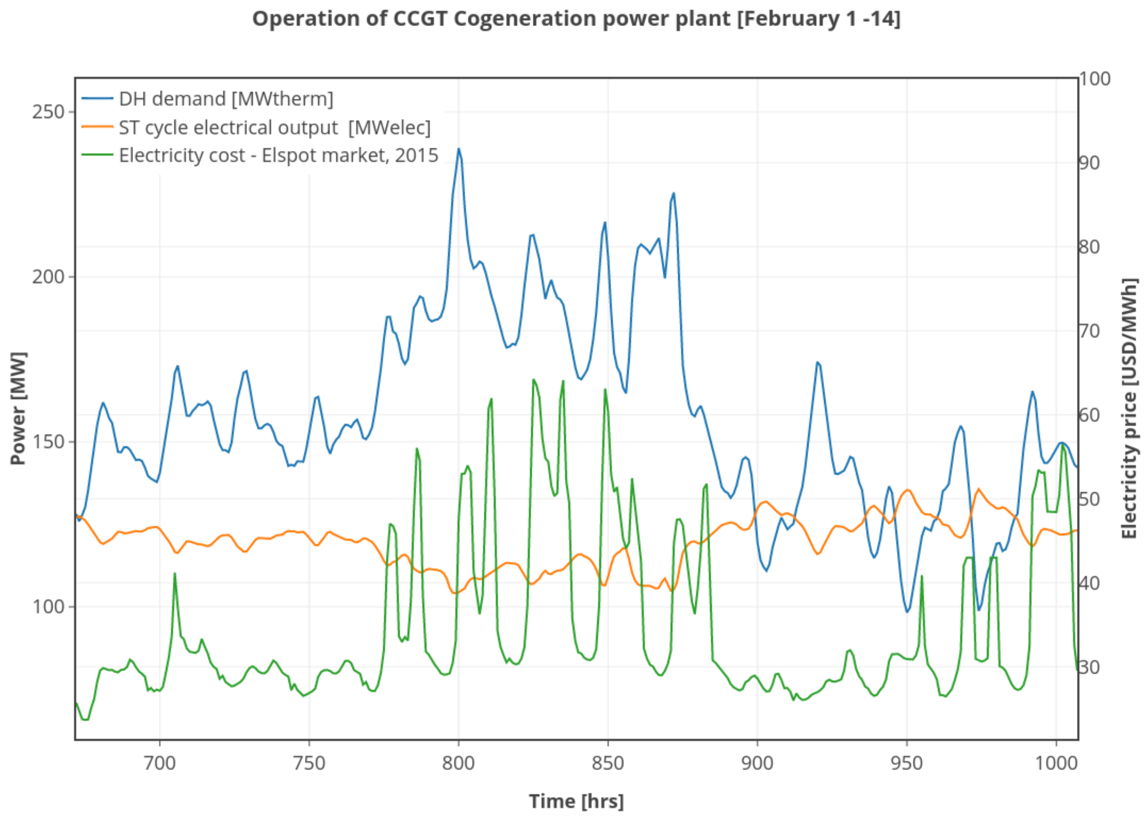

Figure 5.1 Influence of DH demand in ST electrical output

With higher heat generation in operation mode (III) of about 2190 GWh and 33.47% of thermal efficiency, the net plant efficiency reaches maximum of about 86.05% followed by 67.81% and 62.47% in mode (II) and (I) respectively. It is seen that generating more heat energy increases the net plant efficiency of the power plant.

Heat rate, which refers to energy required to produce one KWh of electricity is low for pure condensing mode considering highest electricity generation. For pure condensing mode, 6173.6 KJ of fuel energy is needed to produce 1 KWh of electricity and maximum of 6848.8 KJ of energy while operating in design alpha value. If thermal rate is calculated for three modes of operation, which refers to fuel energy needed to produce 1 KWh of thermal energy. Pure condensing operation results in highest energy usage to generate 1 KWh of heat energy considering minimum heat generation.

To analyse performance of storage system, two weeks of operation which has a record of highest DH demand, 239.18 MW in operation mode (II) is chosen. DH demand, electricity prices in Nordpool market [31] and electrical generation in ST cycle during this two weeks of operation is shown in Figure 5.1. It can be seen from the figure, steam extraction is influenced by the DH demand and rest of the steam available in the steam cycle is used for electricity generation in the power block.

One more thing to notice from Figure 5.1 is that electricity prices has two peaks in each 24 hours and during these peaks DH demand is also higher. DH consumption and electrical consumption behaviour are almost in similar pattern. If DH demand generation is able to shift towards non-peak electricity hours, power plant can take advantage of high electricity prices and improve revenue of the power plant. This part will be briefly discussed in operation of thermal storage system.

Performance evaluation of cogeneration systems is discussed in section 4.2.3. Recollecting from the definition of cogeneration, annual electricity generated from CHP plants are considered cogenerated only if the annual overall efficiency is higher than 80%. 80% is threshold efficiency of the cogeneration system contains extraction-condensing turbines [14]. From Table 5.1, net plant efficiency during operation mode (I) and (II) are less than threshold efficiency. So it is necessary to differentiate between cogenerated electricity and non-cogenerated electricity in the annual performance. Cogeneration performance is evaluated for operation mode (II) and shown in Table 5.2. In this mode of operation, cogenerated electricity accounts for 45.8% of annual electricity generation and rest are non-cogenerated electricity. Also, fuel energy utilized for CHP and non-CHP operation is calculated to include tax on fuel consumption for heat and electricity generation.

Cogeneration parameters	***Value***	
$\eta_{threshold}$	*80*	*[%]*
Electrical output (CHP)	*1700.4*	*[GWh]*
Electrical output (Non-CHP)	*2005.9*	*[GWh]*
DH output	*730.85*	*[GWh]*
Fuel energy CHP	*3039.1*	*[GWh]*
Fuel energy Non-CHP	*3504.4*	*[GWh]*

Table 5.2 Cogeneration performance evaluation in operation mode (II)

5.2 Economic and environmental performance – no storage operation

Economic and environmental performance of the power plant is discussed for three modes of operation explained in the above section. Specific investment cost of the combined cycle cogeneration power plant is 740.42 USD/KW_{elec}, refers to investment cost required to build one KW_{elec} capacity of CCGT CHP power plant.

Levelized cost of electricity (LCOE) is an economic assessment to compare electricity generation costs from different power plants. It is first order economic assessment to check cost-competitiveness of power plants in the market. In this study, LCOE is calculated for three different modes of operation to analyse the competitiveness between generating electricity and heat energy in the power plant. In total costs, revenue from DH supply has to be deducted in order to calculate LCOE for electricity. A fixed heat credit of 28.33 USD/MWh_{therm} is used to calculate expected revenue from DH supply [30] and the cost of water consumed in the power cycle is 2.84 USD/m^3 [10].

LCOE of CCGT CHP power plant in three different modes of operation is shown in Table 5.3. The minimum LCOE of electricity is 59.17 USD/MWh_{elec}, achieved by operating power plant in design alpha value. In this mode, maximum heat generation plays a significant role in bringing down the electricity costs. LCOE of power plant operating in pure condensing mode and mode (II) are 65.85 USD/MWh$_{elec}$ and 64.75 USD/MWh$_{elec}$ respectively.

Performance indicators	*Mode (I)*	*Mode (II)*	*Mode (III)*
LCOE [USD/MWh]	65.85	64.75	59.17

Table 5.3 LCOE of CCGT CHP power plant in different modes of operation

LCOE breakdown of the power plant in different modes of operation is made and shown in Figure 5.4. All the costs associated with LCOE are converted into per MWh$_{elec}$ generated to analyse the contribution of each costs. From the table, it can be seen that revenue from DH supply in mode (III) plays a significant role in bringing down LCOE of this operation to 59.17 USD/MWh$_{elec}$. There is not much difference in contribution from investment costs and decommissioning costs in different modes of operation. Operation & maintenance costs have significant influence in three modes of operation due to difference in net electricity generation and highest cost contribution.

LCOE breakdown [USD/MWh$_{elec}$]	*Mode (I)*	*Mode (II)*	*Mode (III)*
Investment costs	7.90	8.1407	8.76
Operation & Maintenance costs	59.89	62.13	68.36
Decommissioning costs	0.06	0.06	0.07
DH sales	-2.02	-5.58	-18.03
LCOE	65.85	64.75	59.17

Table 5.4 LCOE breakdown of CCGT CHP power plant in different modes of operation

Following economic performance, environmental performance study of the power plant is important to keep the emission level in check and also to compare with other power plant designs. Specific emissions and specific water consumption of the power plant is estimated and shown in Table 5.5. Specific emissions and water consumption of the power plant in different modes of operation is calculated using equation (3.12 and 3.13). For operation with net plant efficiency less than 80%, cogenerated performance is evaluated and fuel used for electricity and heat generation are calculated using their respective efficiencies. It can be noticed that specific carbon dioxide emissions for electricity generation is maximum for pure condensing method, 328.3 Kg/MWh$_{ele}$. For operation of power plant in design alpha value, specific emission is lowest among three modes and the net plant efficiency is greater than threshold efficiency of cogeneration system. So, the fuel is apportioned equally for electricity and heat generation.

Performance indicators	*Mode (I)*	*Mode (II)*	*Mode (III)*
Specific CO_2 emissions – heat [Kg/MWh$_{therm}$]	*252.5*	*252.5*	*237.4*
Specific CO_2 emissions – electricity [Kg/MWh$_{elec}$]	*328.3*	*306.8*	*234.7*
Specific water consumption [l/MWh$_{elec}$]	*47.35*	*42.26*	*24.77*

Table 5.5 Environmental performance indicators at different modes of operation

Specific water consumption represents quantity of water required to generate electricity in the power plant, which includes water used in power cycle and condenser. From the table, it can be seen that pure condensing mode (I) indicates higher specific water consumption because all the energy available in the steam cycle are condensed to maximize electricity generation.

5.3 Performance analysis of the power plant with storage system

In this section, performance of the power plant on integration of storage system is analysed. The general layout of a CHP plant with storage system is shown in Figure 1.12 for understanding the power plant operation.

To study the performance of the storage system, a specific time period is chosen and the reason is justified. It can be observed from the above section that LCOE of electricity is higher when the power plant focusses on maximizing electricity production and also identified that increasing heat generation brings down the LCOE of the power plant. The Average electricity price of day-ahead market in Nordpool spot market [31] is 23.71 USD/MWh$_{elec}$. By comparing average electricity price and LCOE values obtained in the analysis, it can be observed that the power plant will be shut off during most of the summer period for economic reasons. So in this study, a time period of two winter months (January, February) is chosen to simulate storage system and results of two weeks are used to analyse the economic benefits on operation.

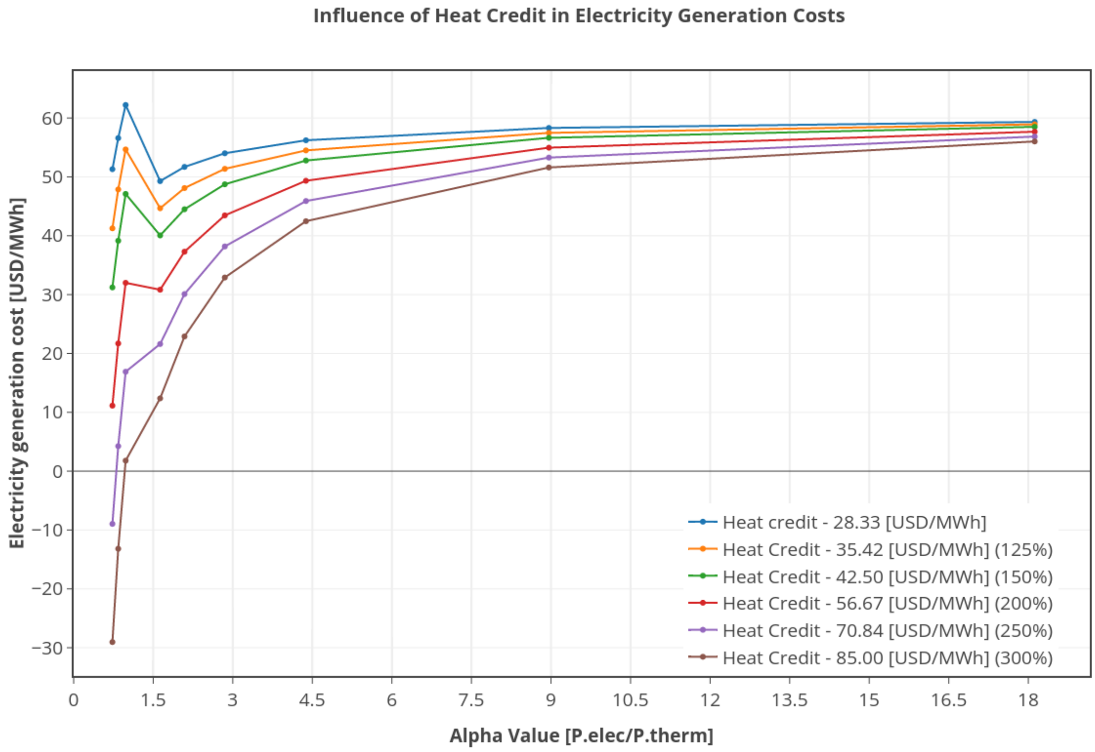

Figure 5.2 Electricity generation cost curve at different heat values

The power plant with storage system is simulated using control strategy shown in Figure 4.10. Before analysing the results, one of the inputs given to the simulation model is electricity generation cost curve. Cost of electricity generation refers to an estimate of electricity generation cost per MWh_{elec} obtained by deducting district heating value supplied from total running costs of the power plant. Total running cost of the power plant is mostly dominated by fuel costs in this case. Using these data, a cost curve is developed for different heat generation at different heat credit values. This cost curve shown in Figure 5.2 and in the x-axis, the alpha value of the power plant is calculated by varying heat generation (408 – 25 MW) and electricity generation (293 – 453 MW).

Cost curve at heat credit 70.84 USD/MWh_{therm} is chosen for calculating economic benefits of storage system. In Figure 5.3, the modified heat generation when operating with thermal storage system and the DH generation of the power plant without storage system is shown and compared. The new modified heat generation is predicted in the simulation by considering market electricity prices, energy available in storage, maximum charge and discharge rate, heat energy to be supplied.

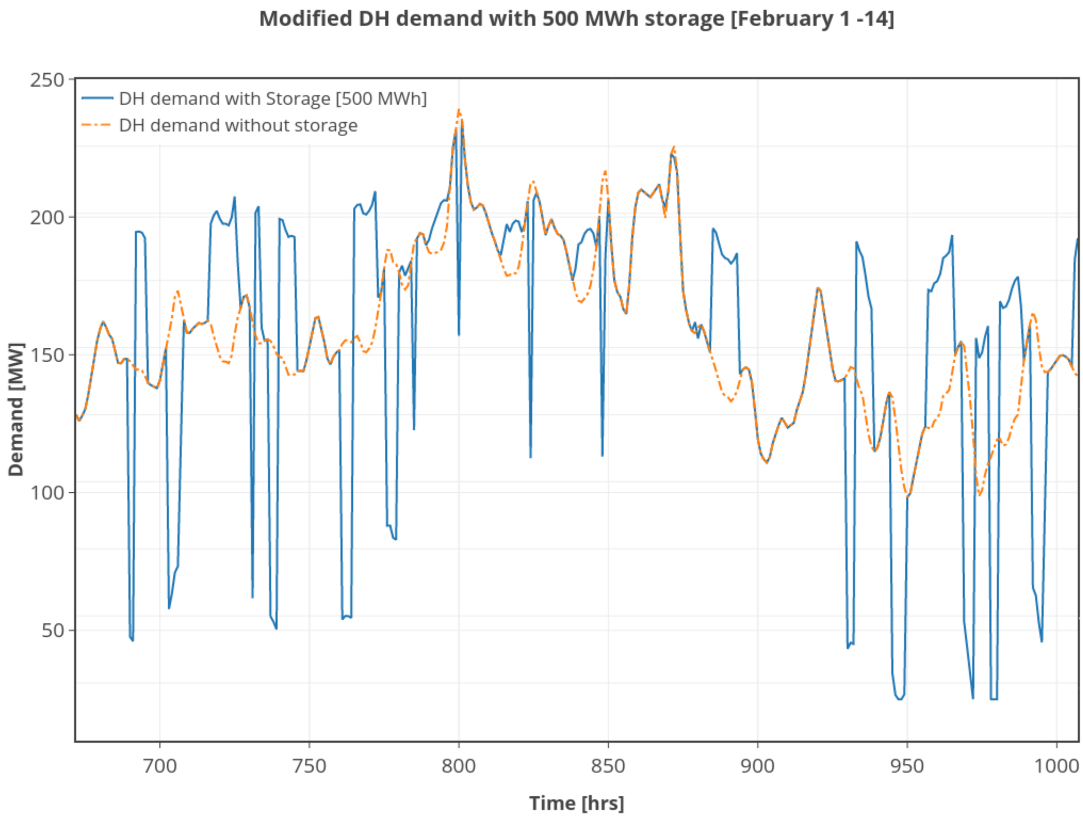

Figure 5.3 Modified DH generation in power plant with storage

The modified heat generation directly influences the steam extraction and also electricity generation in the steam cycle. The cumulative energy available energy at any moment, dispatch and charging of the storage system, modified ST cycle generation is shown in Figure 5.4. The minimum energy of 50 MWh is always maintained in the thermal storage system as a technical constraint.

In the new modified operation, power plant takes advantage of high electricity prices in each 24-hour interval according to the control strategy explained. The economic improvement of about 12,800 USD in two weeks is obtained by operating power plant with 500 MWh of thermal storage system. During the operation, the ramp up and ramp down observed in the ST cycle generation is 12 MW/h and 14 MW/h.

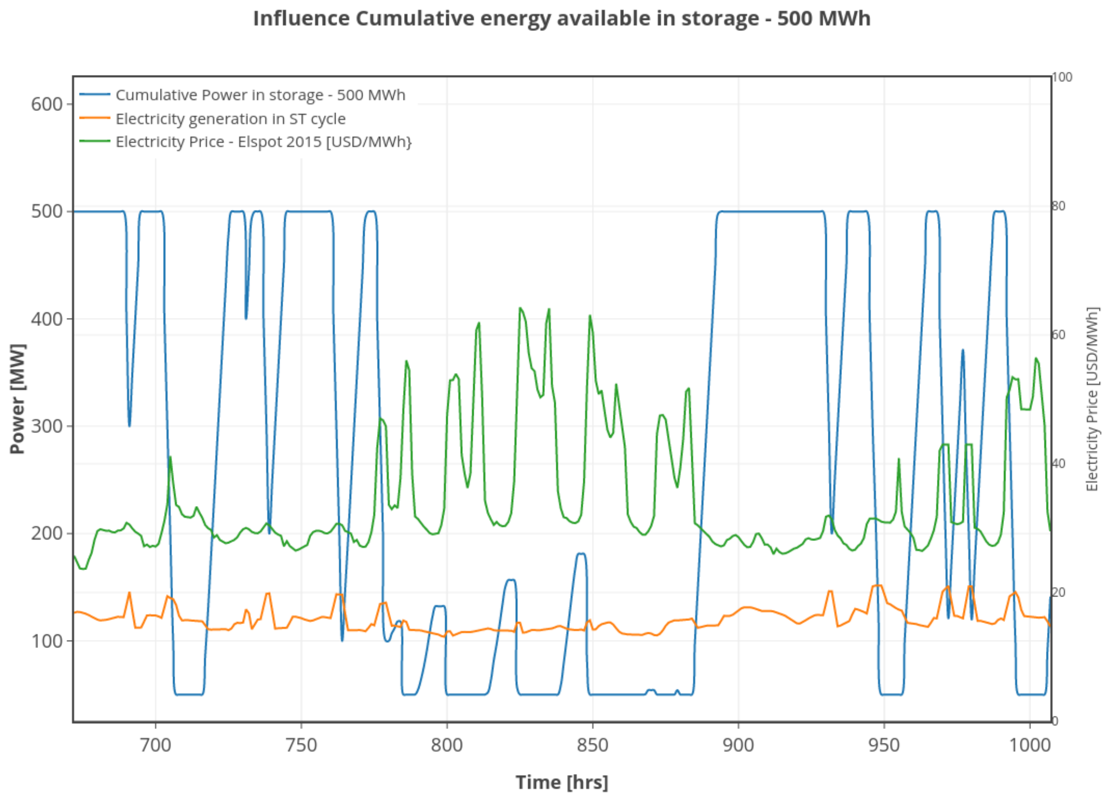

Figure 5.4 Status of thermal storage system and ST cycle generation

It is seen that storage system provides flexibility in operation of the power plant to take advantage of electricity prices and at the same time, demanded district heating energy is supplied at all instant. This kind of operation will be very profitable for cogeneration power plants operating in district heating base load operation. In order to implement developed strategy in real time, accurate forecast on electricity prices and a synchronized platform connecting power plant and thermal storage is needed to predict optimal DH generation point in the power plant.

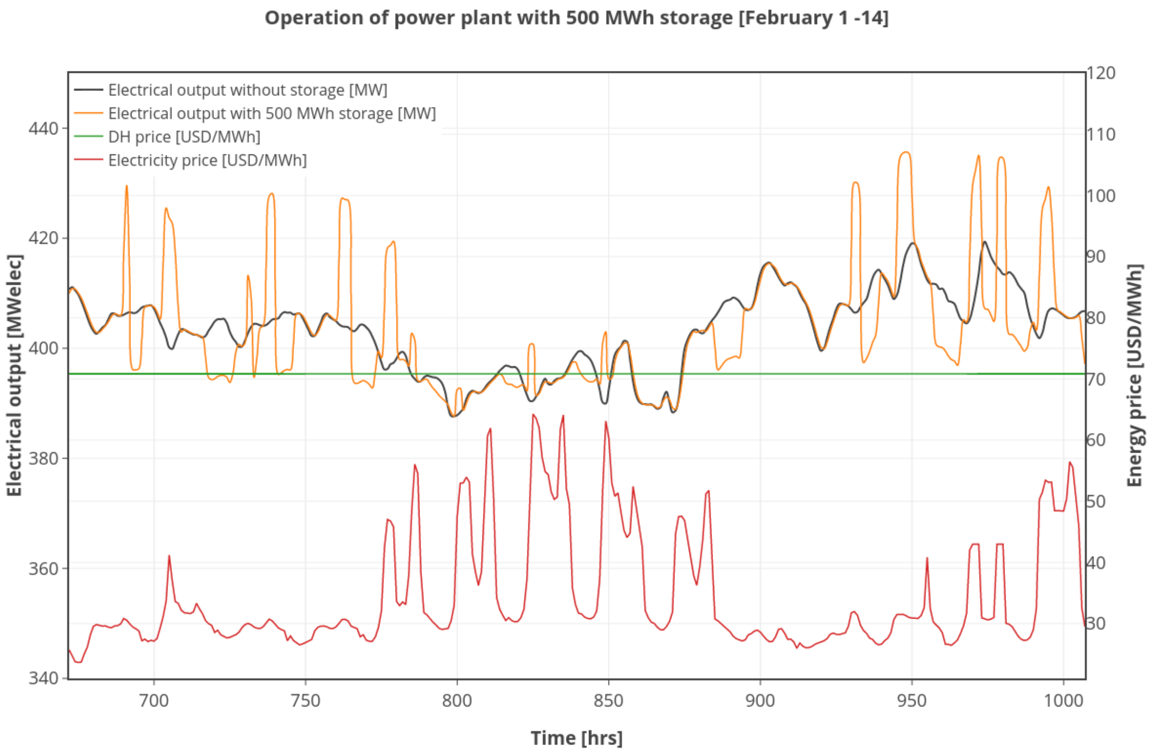

Figure 5.5 Improved operation of the power plant with storage system

6. Sensitivity Analysis

Power plant performance is based on several design parameters and some of them are subject to degree of uncertainty. In order to examine the effects of these parameters in the power plants performance, a sensitivity analysis is made by varying these parameters and studying the effects in the performance. Levelized cost of electricity being an important indicator to compare cost competitiveness of different power plants, a sensitivity analysis is made by varying major economic parameters involved.

In a natural gas combined cycle cogeneration power plant, fuel price plays a significant role in terms of operational costs and also role of heat credit in the LCOE is also discussed in the section 5.1. These two parameters are varied and influence of them in Levelized cost of electricity are analysed in this section.

Later in this section, influence of storage capacity in economic benefits of the power plant is also discussed by varying the storage capacity. It should be clearly understood by this time that storage capacity in this power plant is used as a buffer to shift the demand based on price signals of energy, technical constraints and not as a primary substitute of heat generation in the power plant.

6.1 Natural gas price

Fuel consumption being a major factor for a natural gas powered CCGT CHP power plant, their costs significantly influences the annual operational costs. Natural gas prices tend to vary from time to time and from region to region, it is essential to see influence of natural gas price in levelized cost of electricity of the power plant. For example, the price of natural gas is United States is 80% lower than Europe and in Asia, the natural gas costs are approximately 60% higher than Europe [32]. To analyse the influence of Natural gas price in the LCOE, natural gas price is varied from -15% to 15% with interval of 5%. The reference natural gas price (0%) chosen is 33.19 USD/MWh$_{fuel}$ [26]. The results about influence of natural gas price on LCOE of electricity are shown in the Figure 6.1.

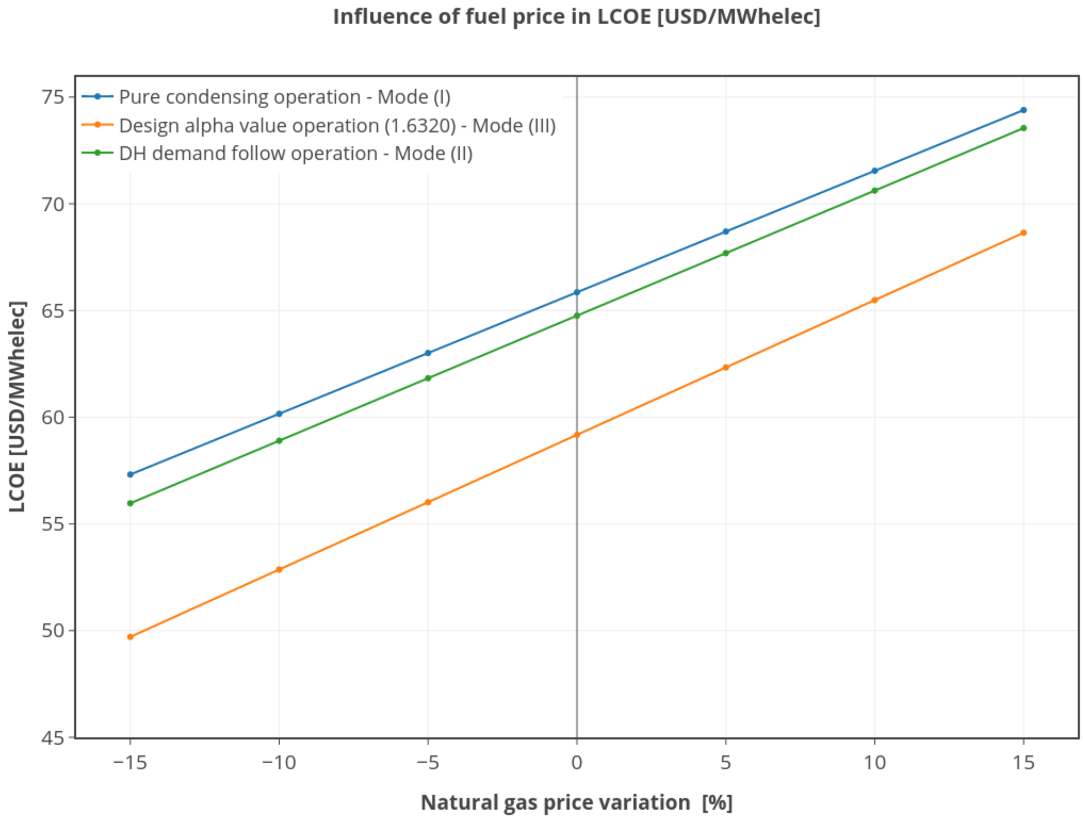

Figure 6.1 Influence of natural gas price in LCOE

It is observed from the above figure that natural gas price has influence in LCOE of electricity. Referring to LCOE breakdown shown in Table 5.4, the change in natural gas price influences the operation & maintenance costs part of the total costs in the power plant. In sensitivity analysis, LCOE of electricity increased for pure condensation operation from 65.85 to 74.39 USD/MWh$_{elec}$ at Natural gas price of 38.18 USD/MWh$_{fuel}$, which is 15% more than reference natural gas price 33.19 USD/MWh$_{fuel}$. Similar influence is found in the other two modes of operation as well.

6.2 Heat credit

Followed by natural gas price, heat credit also has a significant influence in the overall cost of electricity generation. Heat credit is multiplied by amount of heat supplied to calculate the revenue from district heating and the DH revenue is deducted from total costs to calculate LCOE of electricity. Influence of heat credit in levelized cost of electricity for three modes of operation in power plant is shown in Figure 6.2.

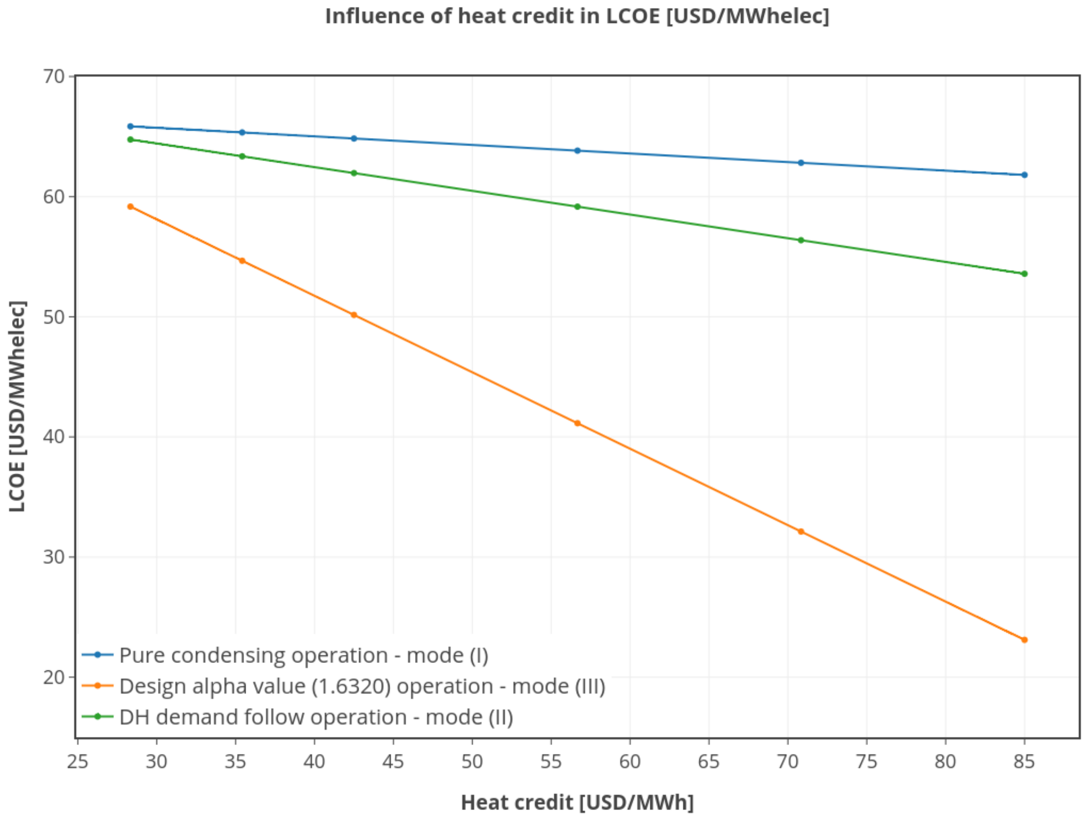

Figure 6.2 Influence of heat credit in LCOE

LCOE variation of the pure condensing mode is not very significant due to its minimum heat generation. The variation of LCOE in pure condensing mode is from 65.85 to 61.80 USD/MWh$_{elec}$ for variation in heat credit price from 28.33 to 85.00 USD/MWh$_{therm}$. On the other hand, LCOE of electricity while operating in design alpha value varies from 59.17 to 23.10 USD/MWh$_{elec}$ for same heat credit variation. The amount of heat generated in different modes of operation directly influences the DH revenue in the total costs and brings down the LCOE of electricity. Variation of LCOE on operation mode (II) is also less significant due to its amount of heat generation.

On comparing the influence of heat credit and natural gas price in LCOE of the CCGT CHP power plant. It is concluded that amount of heat generation has more influence in the LCOE if heat credit value is higher comparing to influence natural gas price.

6.3 Storage capacity

Thermal storage operation has provided opportunity to take advantage of high electricity prices and storage capacity is a prime factor that determines amount of flexibility thermal storage can provide in power plant operation. In this section, thermal storage capacity is varied and the influence of storage capacity on economic benefits is analysed.

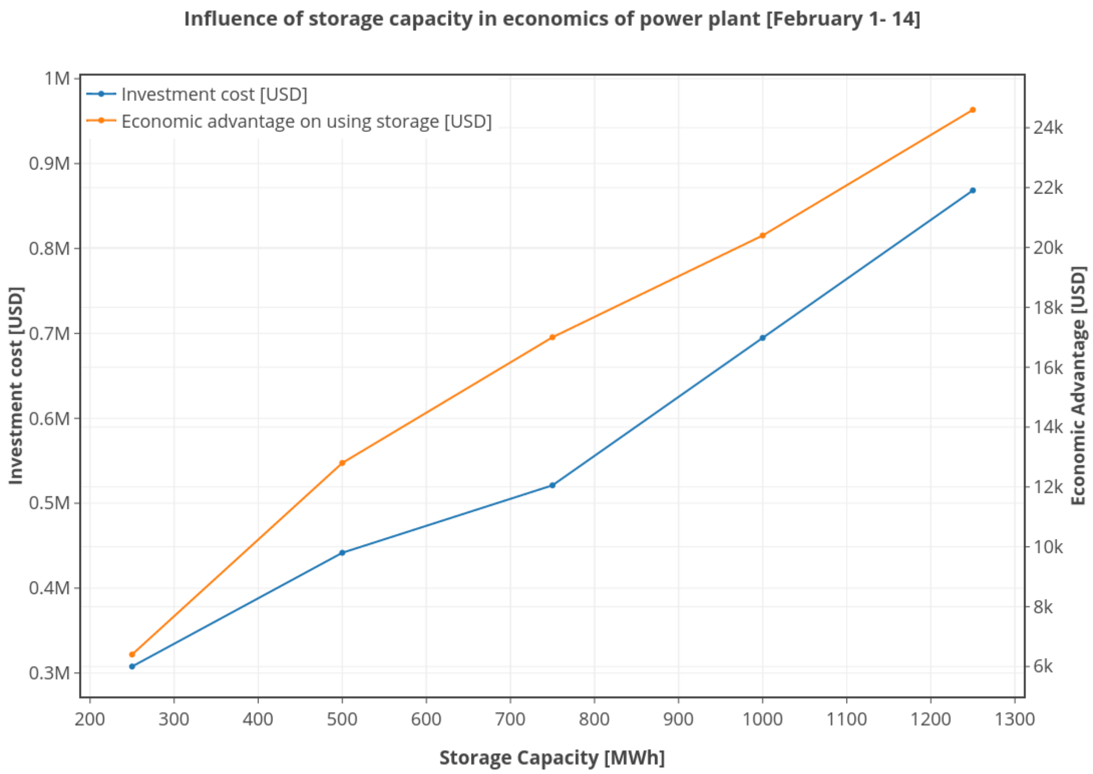

Figure 6.3 Influence of storage capacity in the power plant operation

The storage in the power plant is simulated for two winter months (January, February) and the benefits are represented for two weeks of operation. Capacity is varied from 250 MWh to 1250 MWh with 250 MWh intervals and respective investment cost, benefits are shown in Figure 6.3. From the figure, it can be seen that improving storage capacity has improved benefits ranging from 6,400 USD at 250 MWh to 24,600 USD at 1250 MWh. Choosing the storage capacity is critical and it depends on many factors like investment decisions, operational strategy on participating between heat and electricity markets and demand variations in DH network.

7. Conclusions

In this study, a simulation model of combined cycle cogeneration power plant model is developed in DYESOPT tool. The techno-economic model of the power plant is developed with an objective to test the flexibility options in the power plant operation. Developed model of the power plant includes technical design to calculate the nominal operation conditions, economic design with investment and operational costs, transient simulation model capable of introducing different operational strategy.

First, performance of the power plant without storage system is studied with three different modes of operation at different mix of heat and electricity generation. In the power plant model, extraction-condensing turbine in the steam cycle has proved as an advantage for the power plant to switch between heat and electricity generation. From the results of performance analysis, power plant operation close to design alpha value achieves lowest LCOE of about 59.17 USD/MWh_{elec}. The amount of heat generation is found to have a significant influence in the bringing down levelized cost of electricity.

Secondly, the performance of power plant with storage system is studied. New control strategy is developed for storage system to take advantage of the higher electricity price periods considering technical constraints in the system and the simulation results show that the availability of thermal storage system add technical and economic value to the power plant. In two weeks of operation with storage system, an economic improvement of 12,800 USD is achieved.

Finally, a sensitivity analysis is made to analyse the influence of economic parameters in the operation of the power plant and concluded that heat crediting and amount of heat generation is found to be having significant influence in bringing down levelized cost of electricity.

Future work

Development of the combined cycle cogeneration power plant model is an initial step in realizing the possibilities of services these kind of power plants can provide in the future energy system. This study focusses on the complete model development of the power plant including technical and economic design of the power plant. Implementing new operational strategy, integrating new fuel source, storage system could be tested in future. A key limitation of the power plant model is that turbine transients including start up and shut down of the power plant and ability to operate in altered load profile is to be implemented in the future. Some of the main tasks that can be performed as next steps are,

- Including turbine transients and realizing the potential of thermal storage system by comparing with real operational data of Öresundverket.
- Conduct a techno-economic analysis to realize the possibility of integrating biomass as a fuel source to reduce net CO_2 emissions.

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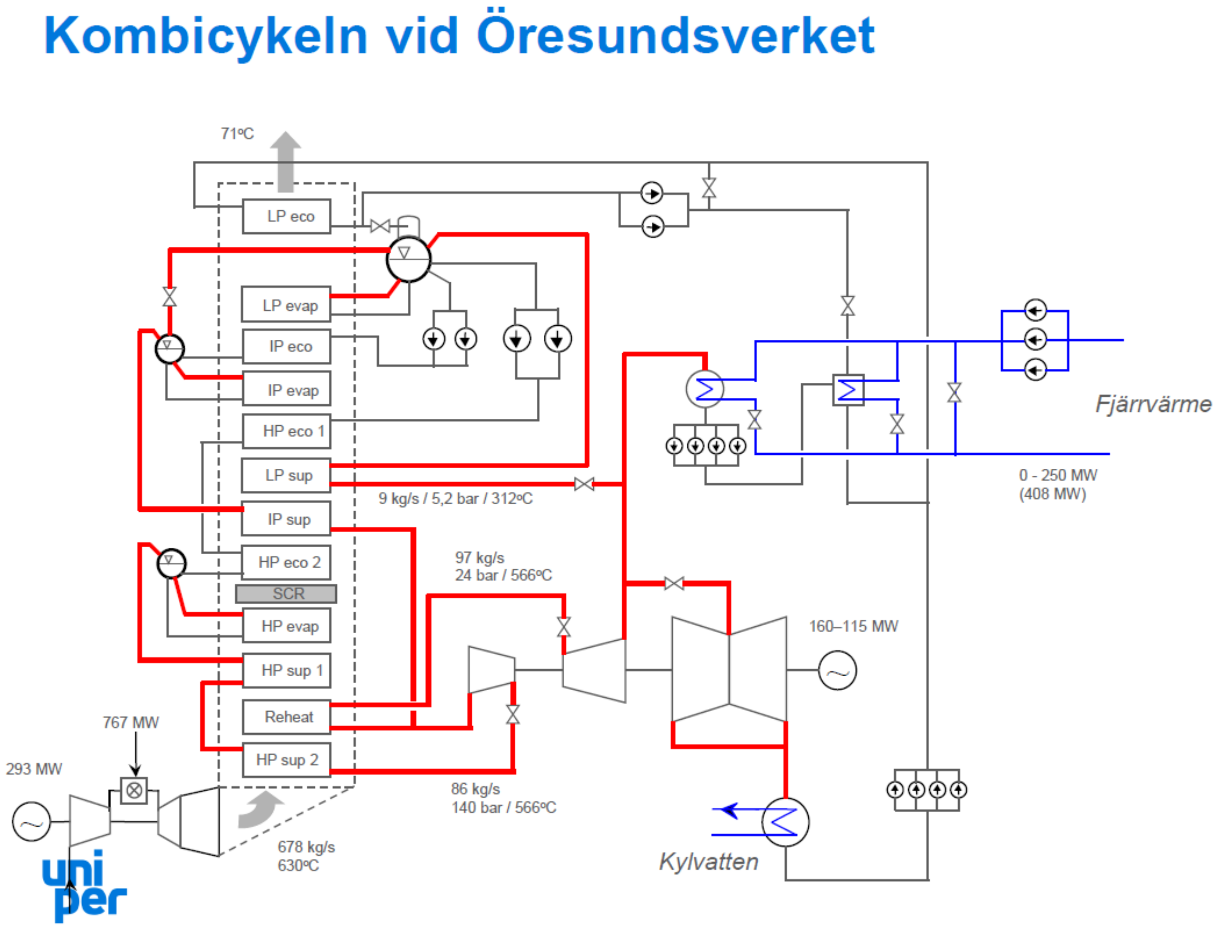
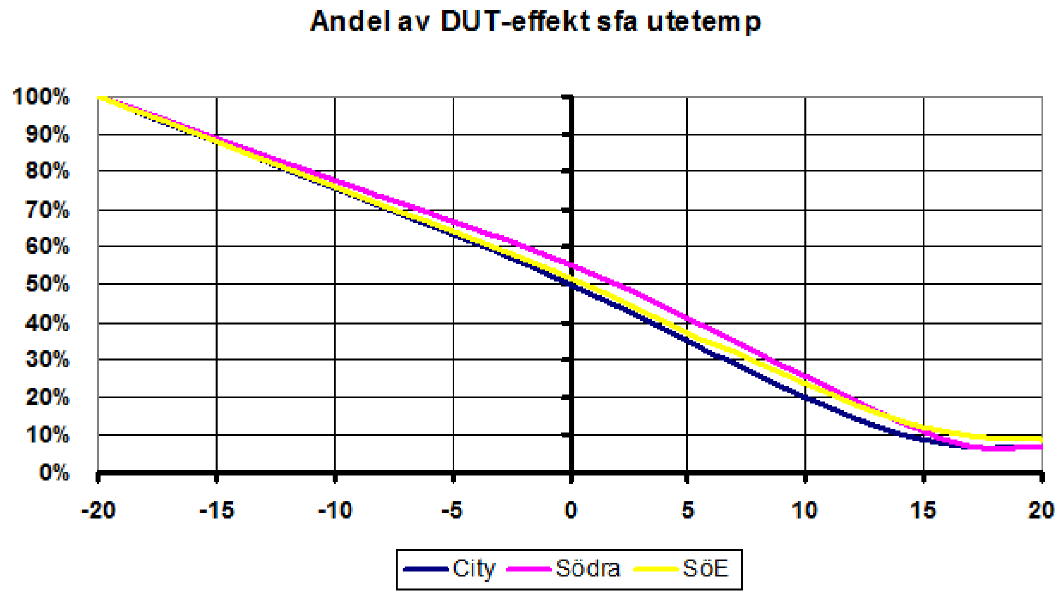
Appendix

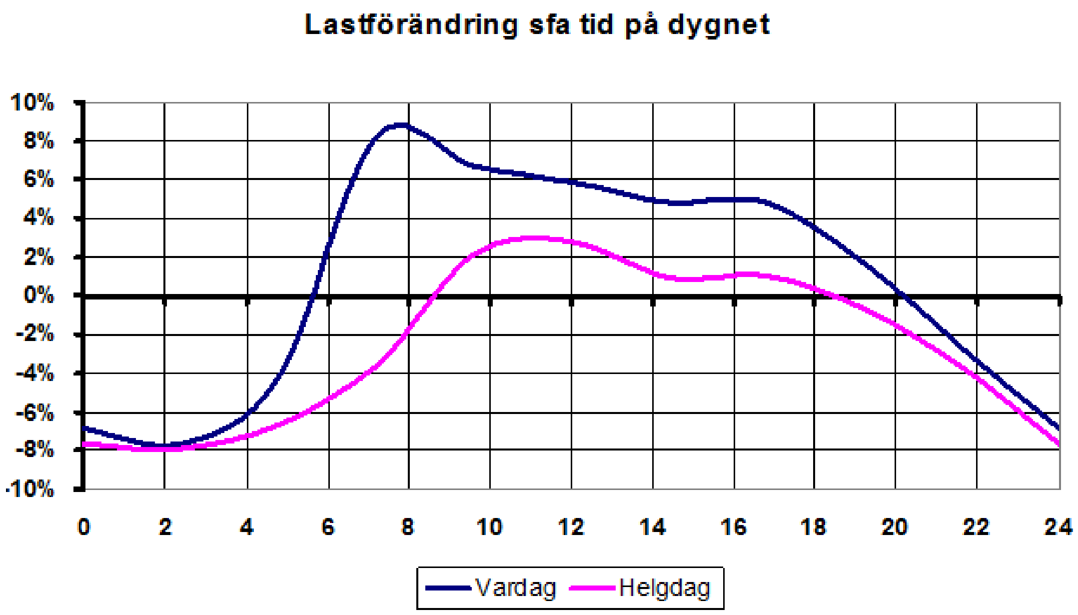
Öresundsverket Power plant, Sweden



Statistical data of CHP power plant DH dispatch data

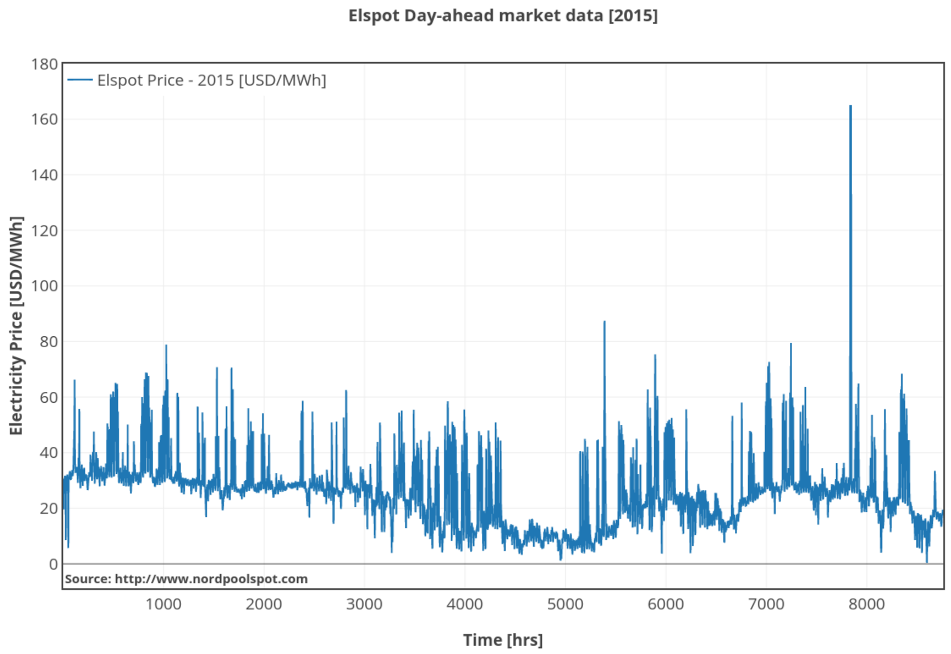


Influence of ambient temperature in plant's DH demand

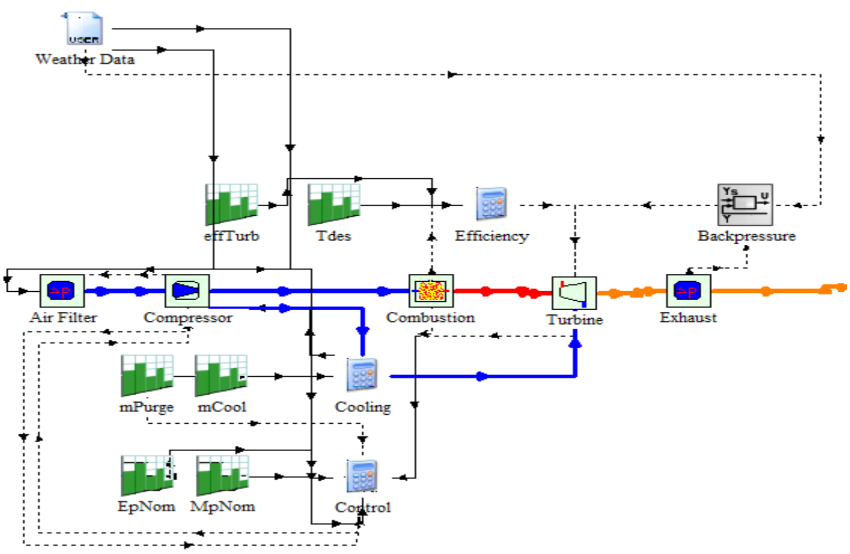


Variation of social load in holidays and working days

Electricity price of day-ahead market in Sweden, 2015



TRNSYS model of GT cycle



TRNSYS model of ST cycle