THESIS FOR THE DEGREE OF LICENTIATE OF ENGINEERING

Combined heat and power plant flexibility

Technical and economic potential and system interaction

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Abstract

The share of variable renewable energy sources in electricity generation systems is expected to increase, leading to increased variability in the load that must be provided by conventional power plants or other flexibility measures. Thus, thermal power plants need to consider implementation of technical measures that enhance flexibility; to maintain profitability of operation with increased electricity price fluctuation, and to support electricity system stability.

This thesis investigates the technical and economic potential for flexible operation of combined heat and power plants that deliver heat to district heating networks; in current and future Swedish energy system scenarios with varying levels of electricity price volatility.

A modeling framework is developed to analyze static, dynamic, technical and economic aspects of flexible combined heat and power operation; comprising steady-state and dynamic process simulation models that are validated with reference plant measurements; and dispatch optimization models. Based on the designs of a waste-fired and a gas turbine combined cycle reference plant, two options to enhance the plant operational flexibility are analyzed: 1) product flexibility; i.e. operating the steam cycle with varying product ratios of electricity, heat and frequency response; 2) thermal flexibility, allowing the heat production to be shifted in time.

The results show that flexible operation, for variable electricity generation, is technically feasible in both plant types. Operation with product and/or thermal flexibility can increase the annual plant revenue with up to 90 k€/MW by reduced fuel consumption or increased full load hours. The economic impact of increased ramp rate (operational flexibility) is marginal (<6 k€/MW). The value, and utilization, of flexibility enhancing measures increase with electricity price volatility, that benefits plants with a wide load span for electricity generation and motivates a shift in operating strategy from the traditional heat-following production planning to electricity-following operation.

Keywords: Combined heat and power; Flexibility; District heating; Dynamic modeling; Process optimization modeling; Waste to energy; Combined cycle; Electricity price volatility

List of publications

The thesis is based on the following papers, which are referred to in the thesis by their Roman numerals:

I. Beiron, J.; Montañés, R.M.; Normann, F.; Johnsson, F. *Dynamic modeling for assessment of steam cycle operation in waste-fired combined heat and power plants.* Energy Conversion and Management. **2019,** 198, 111926**.**

II. Beiron, J.; Montañés, R.M.; Normann, F. *Operational flexibility of combined heat and power plant with steam extraction regulation.* In proceedings of: 11th International Conference on Applied Energy. **2019**.

III. Beiron, J.; Montañés, R.M.; Normann, F.; Johnsson, F. *Combined heat and power operational modes for increased product flexibility in a waste incineration plant.* Energy. **2020**. DOI: 10.1016/j.energy.2020.117696.

IV. Beiron, J.; Montañés, R.M.; Normann, F.; Johnsson, F. *Flexible operation of a combined cycle cogeneration plant – A techno-economic assessment.* Submitted for publication. **2020**.

Author contributions

Johanna Beiron is the principal author of all papers. Dr. Rubén M. Montañés contributed with discussion on the development of process simulation models and discussion and editing of all papers. Associate Professor Fredrik Normann contributed with discussion and editing of all papers. Professor Filip Johnsson contributed to the discussion and editing of Papers I, III and IV.

Other publications not included in the thesis

- Beiron, J.; Normann, F.; Kristoferson, L.; Strömberg, L.; Garðarsdòttir, S.Ò.; Johnsson, F. *Enhancement of CO_2 absorption in water through pH control and carbonic anhydrase – A technical assessment.* Industrial & Engineering Chemistry Research. **2019**, 58, 14275-83.

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Johanna Beiron, Göteborg, April 2020.

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1. Introduction

As a way to decarbonize the energy sector, the share of electricity generation from variable renewable energy sources, for instance wind power in Northern Europe, is expected to have a strong increase in power systems [1]. To cope with the variability of wind power generation, flexibility measures are needed to maintain balance between supply and demand. Electricity system flexibility can be provided by four main technical solutions: dispatchable generation, electricity storage, transmission to neighboring systems or sectors, or demand side management [2]. Due to the low operating cost of wind power, price incentives for electricity system flexibility through volatile electricity prices are expected; with high- and low-price periods depending on wind conditions. Traditionally, dispatchable generation has been the primary solution to manage variability in demand, by cycling mid- and peak-load power plants. However, the increased variability introduced by variable renewable energy sources might affect also base-load power plants and lead to a reduction of full load hours, making it more difficult to recover investment costs. Therefore, power plants might benefit from increased flexibility in their operation; both as a means of supporting the electricity system, and to gain resilience towards fluctuating market conditions.

In Sweden, thermal power plants (excluding nuclear) are normally operated as combined heat and power (CHP) plants that cogenerate electricity and heat for local district heating networks. District heating is conventionally seen as the main product and the plant is dispatched according to the heat demand profile. Electricity is considered a byproduct that increases the plant revenue (with favorable electricity prices). However, with increased wind power generation and electricity price volatility, the profitability of CHP plants is challenged. Given that heat is the main driver for plant operation, plant owners might consider investing in heat-only boilers with low investment costs, rather than the more capital-intensive CHP plants.

On the other hand, the energy system will benefit from having reliable power generating capacity, for example CHP plants, when the electricity generation from wind power is low. Additionally, from a city-level perspective, local electricity generating capacity with flexibility can have a high value as the electricity demand in cities grows at a faster rate than the transmission system capacity [3]. With local limitations on electricity transmission, high levels of wind power generation will not help cities with a capacity deficit. CHP plants are in general situated close to consumers of heat and electricity and can provide support to local energy systems.

Thus, there are two contradicting perspectives on the continued use of CHP plants: from a plant perspective, CHP plants may become unprofitable to operate; while from a system perspective, CHP plants may be important to ensure reliable electricity supply when, and where, it is needed. Increased levels of flexibility can be beneficial for CHP plants in any case, to cope with electricity price fluctuations and to support the electricity system balance.

1.1 Aim

This thesis looks at CHP flexibility from a plant perspective, with the overarching aim to provide an understanding of drivers and limitations for implementation of flexibility in CHP plants, as a means to support the transition to a sustainable energy system. Both technical and economic factors are analyzed, with respect to scenarios for the surrounding energy systems, to get an integrated overview of the value of flexibility. Specifically, the thesis aims to:

- Characterize the technical potential for flexibility in combined heat and power plants
- Analyze the impact on operational patterns of flexibility, and the utilization of technical measures that increase flexibility.
- Evaluate, from a plant perspective, the value of flexibility in electricity system contexts with differing levels of electricity price volatility.

- Compare the technical and economic potential for flexibility in different types of CHP plants that are traditionally considered flexible or inflexible.

1.2 Outline of the thesis

The thesis consists of a summarizing essay and four appended papers. The summary contains six chapters. Chapter 1 places the work in a context and introduces the objectives of the thesis. Chapter 2 provides background and definitions for the types of flexibilities considered in the work: operational flexibility, thermal flexibility and product flexibility (relating to a variable product mix of electricity/heat/frequency response). Chapter 3 presents an overview of the method, while Chapter 4 briefly introduces the modeling work. A selection of results is given and discussed in Chapter 5. The thesis is concluded in Chapter 6, with an outlook on future work. Figure 1 illustrates the scope of the four appended papers, with connections to models, plant types and flexibilities:

- In **Paper I,** a dynamic process model of a waste-fired combined heat and power steam cycle is developed for simulation of transient *operational flexibility* characteristics, considering thermal input load changes and disturbances in district heating return temperature and flow.
- **Paper II** continues on the work of **Paper I**, by looking at transient characteristics of *product flexibility*, focusing on transitions between electricity and heat producing modes of operation, using a steam turbine bypass.
- **Paper III** presents a dispatch optimization model that investigates the utilization and value of *product flexibility* and *thermal flexibility* for the waste-fired plant in different energy system contexts, where the electricity price volatility varies.
- **Paper IV** combines the methods developed in **Papers I** and **III** but focuses on flexibility in a cogeneration combined cycle. All three flexibility measures are evaluated (*operational, product & thermal*) with respect to the impact on plant revenue and operational patterns.

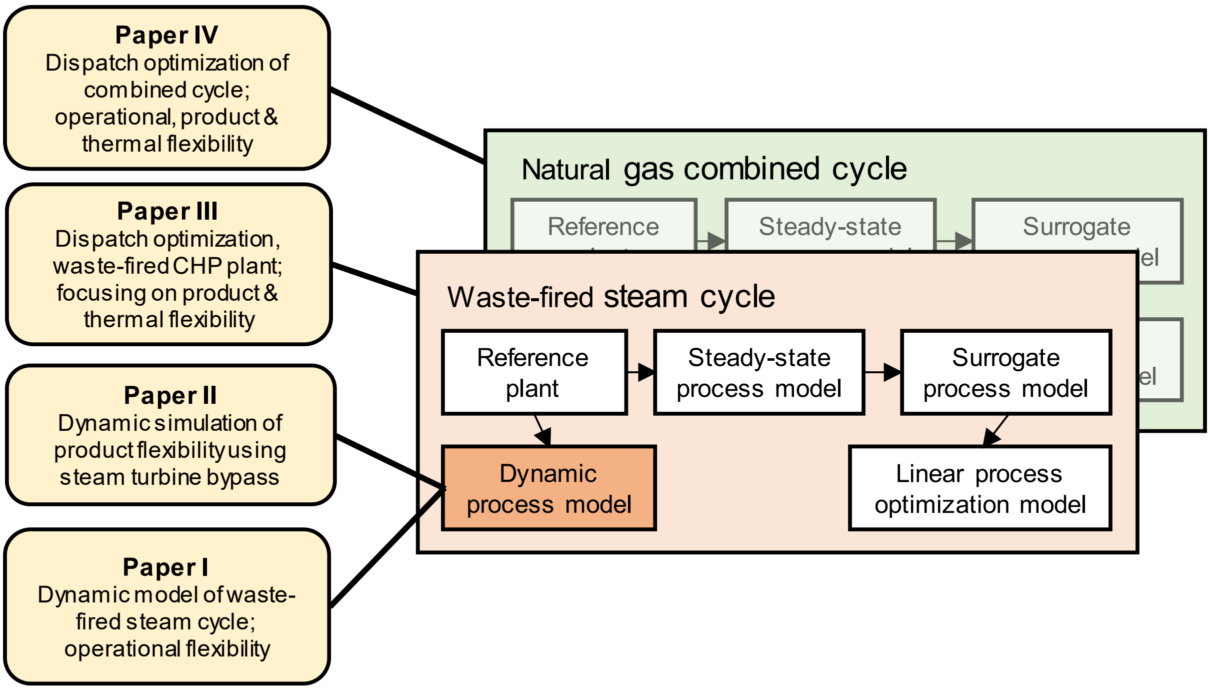

Figure 1. Overview of the four appended papers and flexibility measures considered with connections to models and plant types.

2. Flexibility

The term "Flexibility" is vague and can have different meanings and interpretations in different contexts. This section defines different flexibilities and provides a description of flexibility from the perspectives of 1) the electricity system; 2) power plants in general; and 3) combined heat and power plants in specific. An overview of related work on power plant flexibility is also given.

Three types of flexibility are studied in this thesis, defined as:

- **Operational flexibility**: the ability of a plant to vary electricity output by adjusting the input thermal load from the fuel conversion system.
- **Product flexibility**: the ability of a plant to vary the output load of a specific product by adapting product ratios (primarily the ratio between electricity and heat generation).
- **Thermal flexibility**: the total flexibility of the district heating system to which the plant is connected, including dispatchable generation, thermal energy storage, and demand side response; quantified as the amount of heat [MWh] that can be shifted in time.

2.1 The need for flexibility in energy systems

The demand for flexibility in electricity systems arises from the need to maintain system stability, by balancing demand and supply at all times. Traditionally, unbalance emanates from variations in demand from electricity consumers, and the supply side (power plants) has adapted its generation accordingly. With the increase in variable renewable electricity generation in electricity systems, variations might instead become dominated by the generation profiles of wind or solar power, adding to the variability that must be handled by controllable generation sources or other flexibility measures.

Figure 2 shows an example of a residual (net) load curve; i.e. the share of the electricity demand that must be provided by electricity system components with flexibility (dispatchable power plants, electricity storage, transmission or demand side response) [2]. The residual load curve is specific for a given system context, and its shape and volatility depend on the total variability present in the system at any point in time. The need for flexibility to manage the residual load curve variability can be characterized by three main parameters:

- The **magnitude** of load changes needed, i.e. how much electricity generating capacity must be available to increase or decrease production, ΔP.
- The **rate** of load change required, i.e. how fast this capacity must be activated, $\Delta P/\Delta t$.
- The **duration** of the load increase or decrease, i.e. for how long the new load level must be sustained, $P\Delta t$.

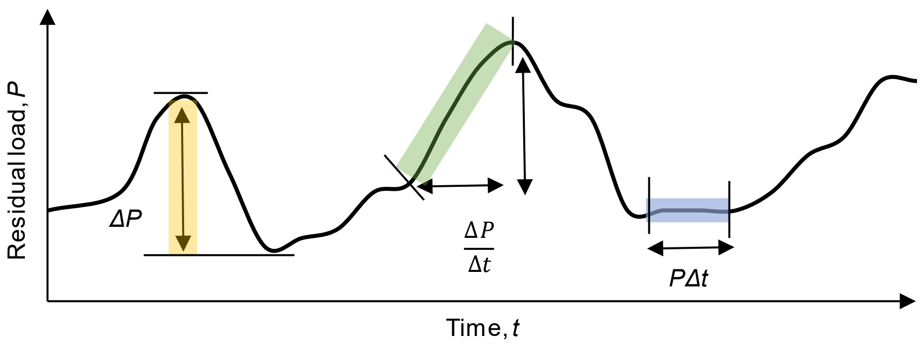

Figure 2. Illustration of a theoretical residual load curve for an electricity system, characterized by the three parameters: magnitude, ΔP; rate, $\Delta P/\Delta t$; and duration, $P\Delta t$.

These parameters will define the type and amount of flexibility measures needed in a specific system context, as different technology types and variation management strategies have different potentials for each parameter. For instance, electricity storage in batteries have fast ramp rates and can provide a high capacity at short notice, but has a limited potential for cost-effective energy storage and consequently will not be able to sustain the capacity for extended time periods [4]. Thermal power plants have slower ramp times, but can sustain load changes for long periods, as long as fuel is available and supplied continuously. Thus, a portfolio of technical solutions and strategies will be beneficial to handle a variety of residual load changes.

2.2 Power plant types, roles and operational flexibility spectra

There are several types of thermal power plants that are designed differently based on the type of fuel and system they are to operate in; giving them differing potentials for flexibility. Figure 3 gives an overview of how the most common types of thermal power plants rank based on parameters that define the operational flexibility of the plant: minimum load level, ramp rate, start-time and associated costs. Plants with a high level of operational flexibility rank low in minimum load level and start-time, with a high ramp rate. Thus, natural gas-fired units are designed with the highest degree of operational flexibility of the thermal plants, while waste-fired and nuclear plants are the least flexible.

Given the cost structure of the plants, they are, traditionally, operated with differing numbers of full load hours. Plants that have low variable costs and high start costs are operated as base-load units in energy systems, running on constant full load for as large part of the year as possible, and are not designed for frequent ramping or cycling; characteristic of inflexible operation. Plants that have the opposite features, with low start costs and high variable costs, are more commonly dispatched as peak-load units that run only when the electricity demand is high; indicating flexible operation.

However, with large-scale introduction of variable renewable electricity generation in power systems, there will be different requirements on the operation and use of power plants. The classification of power plants as base or peak load may change into roles that are characterized by energy volume and energy option contributions [5], where energy volume indicates the extent to which a plant provides low-cost, bulk energy over a given time period, and energy option refers to the availability of the plant over a given time period. In systems that are dominated by variable electricity generation, less bulk electricity will be needed from plants that have been designed for base load, and contribution of the plant may shift to be more energy option-focused, implying a need for enhanced operational flexibility. Power plants that are successful in making such transitions might have a larger chance of maintaining profitability.

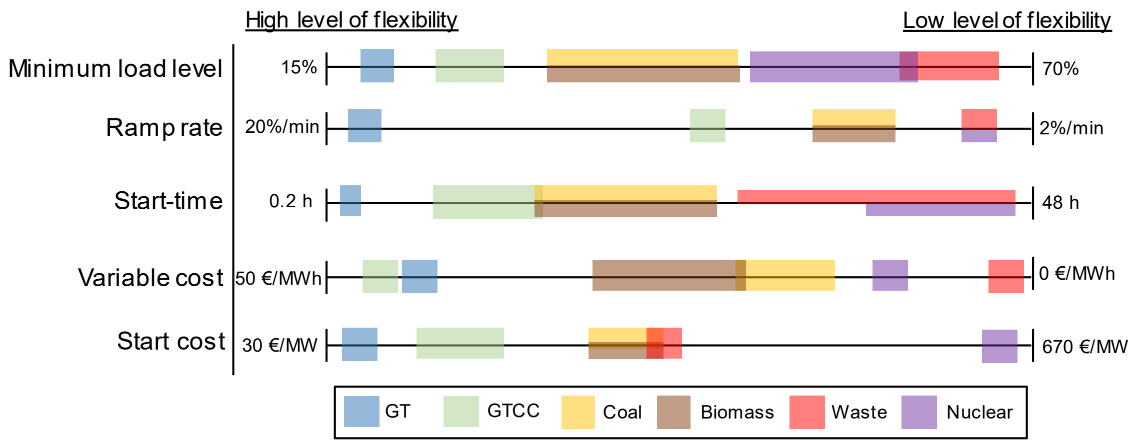

Figure 3. The level of operational flexibility of thermal power plant types. GT = gas turbine; GTCC = gas turbine combined cycle. Based on literature [6,7].

2.3 Opportunities for flexibility in combined heat and power plants

Combined heat and power (CHP) plants are a sub-category of thermal power plants, where electricity and heat are co-produced. The heat is commonly provided to industrial processes with a heat demand, or to local district heating networks that distribute centrally generated heat (e.g. from CHP plants) to consumers (e.g. residential buildings that need space heating and hot water). Cogeneration of heat and electricity increases the plant total efficiency and fuel utilization, but the electrical efficiency is decreased compared to condensing plants in favor of heat generation.

Furthermore, cogeneration gives a possibility to prioritize generation of a specific product, i.e. to vary the ratio between products, in response to fluctuating market conditions or demand levels. This increases both the economic resilience of the plant, but also the plant flexibility, as the operational flexibility can be complemented with product flexibility [8,9]. For CHP plants, heat and electricity are the main products, although these could be complemented with additional options. For example, participation in ancillary service markets, e.g. primary frequency response, could be feasible for CHP plants [10,11]; and biomass-fueled plants might be integrated with production of synthetic biofuels [12–14].

However, given that CHP plants are, at least traditionally, dispatched based on the heat demand profile, the opportunity for product flexibility from CHP plants is limited by the heat demand. Thermal flexibility in the district heating system is the decoupling of heat demand and generation, i.e. to shift the heat load in time, and allows the CHP plants to operate for electricity production independent of the heat demand [15,16]. Thermal flexibility can be provided by, for example, hot water accumulation tanks [17–19] or seasonal heat storages [20,21], thermal energy storage in buildings [22] or the distribution network [23], or by adjusting the dispatch of other heat generation plants in the system. Given that thermal energy is easier to store than electricity, the sector coupling between electricity and district heating systems enabled by CHP plants can be an efficient way to facilitate variation management in both sectors.

2.4 The Swedish energy system

This thesis focuses on combined heat and power plants that are designed for and operated in a Swedish energy system context. The Swedish electricity system is to a large extent fossil-free, and in 2017 the total annual generation of electricity consisted of 40% hydropower, 39% nuclear power, 11% wind power and 10% thermal power from CHP plants. The CHP plants are either plants with a primary focus to deliver heat to a municipal district heating network, or industrial CHP plants that provide heat to industrial processes (and possibly also district heating networks) or use industrial excess heat to drive a steam cycle, for district heating delivery. Among the CHP plants that solely provide heat to district heating systems, biomass and waste are the most commonly used fuels.

The large share of hydropower in the electricity system is a significant asset for variation management. Hydropower can provide low-cost bulk energy, indicative of power plants used for energy volume contributions, and is to an extent also storable, meaning that the availability is generally high. Therefore, hydropower has, historically, been the balancing energy source in Sweden, also providing frequency response and grid stability; and has allowed the CHP plants to be dispatched according to the needs of the district heating system rather than the power sector. However, nuclear power is facing a potential phase-out, and policy measures for increased renewable power generation are in place for a strong expected increase in, especially, wind power; that might change the operating conditions for CHP plants.

2.5 Related work

The field of energy system and power plant flexibility-related research is wide and comprises technical plant-level studies, analyses of economic viability of flexibility measures, and works that investigate the implementation of power plant flexibility from an energy-system perspective. This section gives an overview of current research directions, in addition to the works mentioned in Section 2.3.

Flexible use of the load range of thermal power plants has been considered for different plant types. Measures that have been found to improve the load range flexibility include, for example, load range expansion of gas turbine combined cycles with supplementary firing [24]; and the increase in operational flexibility from steam extraction regulation coupled with plant-internal high-temperature heat storages, from static [25,26] and dynamic [27,28] perspectives. In addition, the importance of minimum load level for plant profitability and energy system planning is highlighted in the literature [29,30], along with tools developed for comparisons of the value of different flexibility-enhancing measures in gas-fired [31] and coal-fired [32] plants, finding that such retrofits can enhance plant profitability.

Thermal power plant ramp rates and transient performance has been studied using dynamic modeling [33], and attention has been given to the negative effect of fast ramp rate; namely, increased thermal stress in metal parts caused by steep temperature gradients, that may lead to component lifetime reduction and increased maintenance costs [34]. Therefore, works have studied optimal operational and control strategies that take into account the effects of thermal stress [35] and component lifetime [36,37], that were found to facilitate enhanced flexible operation and reduce fatigue damage. Additionally, dynamic simulation models have been developed and validated for start-up of thermal plants [38] that could be used to design and optimize cycling procedures.

Dynamic simulation has also been applied for control system studies. The plant's control system is important for operational stability and safety and can improve the response time of the plant if tuned properly [39]. Studies have investigated the implementation of control structures for operational and product flexibility, with boiler-turbine coordinated control strategies for CHP plants with heat accumulators [40]; and transitions between heat-lead and power-lead operation [41], that could increase the power generation ramp rate. Furthermore, flexible operation of power plants integrated with carbon capture units has been studied, concluding that the CO_2 capture process should not significantly affect the load-following capabilities of the power plant [42,43]. Economic model predictive controllers has also been developed [44], showing that CHP operational costs can be minimized by real-time optimization of heat and electricity generation.

From an energy system perspective, increased thermal plant flexibility could reduce wind power curtailment [45] and provide variation management if cycling properties are improved [46]. Additionally, in future energy systems, the operating regimes of thermal power plants might lead to more intense ramping and low utilization, although thermal power remains fundamental for security of supply [47]. Similarly, thermal power plants equipped with carbon capture might also experience low utilization and increased part load operation in future energy systems, leading to increased levelized cost of electricity [48].

The outcomes of the reported studies indicate the potential benefits and uses of technical solutions that enhance flexibility, both from plant and system perspectives. However, studies tend to focus on either the impact on technical performance or the impact on economic performance of flexibility measures, as they are commonly studied using different methodological approaches. Additionally, the focus has, generally, been on coal- or natural gas-fired power plants (not necessarily CHP plants). This thesis contributes to the field by providing an analysis of the potential for flexibility in waste-fired CHP plants, as well as a combined cycle CHP plant primarily suited for district heating delivery. Furthermore, the technical and economic perspectives on flexibility are combined, approaching a holistic assessment of the potential for flexibility in CHP plants.

3. Method overview

This section introduces the main methods for evaluation of flexibility that the thesis is based on, and the two reference plants that serve as a basis for the CHP plant modeling.

3.1 Flexibility assessment

Due to the diverse nature of flexibility as a topic; relating to both technical and economic domains of analysis, as well as static and dynamic performance aspects; this work uses a modeling framework consisting of three types of process models, described in Chapter 4: 1) steady-state process simulation models; 2) dynamic process simulation models; and 3) process dispatch optimization models. Each type of model is developed for two reference CHP plants, see Section 3.2. The following subsections give further descriptions of how each of the three types of flexibility considered in the work (operational, product and thermal flexibility) are analyzed using the modeling framework. Additionally, electricity system scenarios are used to study the impact of electricity price volatility on the CHP operation and revenue, as described in Section 3.1.4.

3.1.1 Analysis of operational flexibility in CHP plants

As stated in Section 2.2, operational flexibility is characterized by the three parameters minimum load level, ramp rate and cycling properties. The technical load range performance is given by steady-state simulation models, while the economic potential is evaluated with the dispatch optimization models. Minimum load level is, thus, a static parameter related to the plant's feasible operating range and is handled jointly with product flexibility, Section 3.1.2.

Ramp rate relates to the transition between operational points and is consequently studied with dynamic simulation models. The impact of ramping the thermal input on the electricity generation response time is analyzed in **Papers I, II** and **IV**. The responses obtained from ramping of three kinds of thermal inputs are compared: gas turbine and supplementary firing load changes in a combined cycle; and thermal input load changes to a waste-fired steam cycle. The economic potential of increased ramp rate is estimated in **Paper IV**, by comparing the dynamic electricity generation with a step change, i.e. if the load change were to happen instantaneously following the change in price signal. The difference in revenue is calculated as:

$$\Delta R = \int_{t_1}^{t_2} C_{el}\left(P_{static} - P_{dynamic}\right)dt \qquad (1)$$

C_{el} is the electricity price, P_{static} is the electricity generation for an instantaneous load change, and $P_{dynamic}$ is the electricity generation for a ramped load change. CHP plant cycling is included in the dispatch optimization model as a cost and a time constant. Dynamic aspects of cycling are outside the scope of this work, due to the complex nature of start-stop transients.

3.1.2 Analysis of product flexibility in CHP plants

In CHP plants, product flexibility may be obtained by adjusting the steam cycle product ratios. Variable product ratios are possible to obtain in practice by operating the steam cycle in "operational modes", that involve the steam turbine bypass or condensing operation. See Section 3.2 and Figure 5 for process configurations, and **Papers III** and **IV** for further details. In this thesis, five steam cycle operational modes are modeled:

- **CHP**: conventional operation with heat and electricity production at a fixed power-to-heat ratio.
- **HOB**: operation with full bypass of the steam turbine, only producing heat from the steam cycle. Gas turbines still generate electricity in the combined cycle case.

- **FRQ**: operation that generates heat and electricity, together with delivery of primary frequency response (FCR-N). The maximum amount of frequency response for a given plant load level is delivered. Gas turbines do not contribute to frequency response in the combined cycle case.
- **COND**: condensing operation, only producing electricity.
- **CFQ**: condensing operation with delivery of primary frequency response.

The performance of the steam cycle modes is simulated using the steady-state models, and the utilization and value of product flexibility is analyzed with the dispatch optimization model. The steam turbine response times for transitions between CHP and HOB modes are simulated with the dynamic model in **Paper II**. Combinations of modes or variable product ratios are feasible, but only the extreme points of each mode are included in the modeling, e.g. only 100% steam turbine bypass operation is considered and no partial bypass options. Other operational modes and products could also be considered, such as integration with carbon capture units or production of synthetic biofuels, but are not included in this work.

3.1.3 Analysis of thermal flexibility in relation to CHP plants

Thermal flexibility is a property of the district heating system and is, thus, treated as a boundary condition to the CHP plants in this work. The impact on CHP plant operation and revenue of varying levels of thermal flexibility is assessed with the dispatch optimization model. The maximum thermal flexibility available for the CHP plant (in MWh of load shifting potential) is specified as a model input. The range of thermal flexibility considered is 0 – 100 000 MWh. As a reference, a hot water accumulation tank is in the order of magnitude of 1 000 MWh. Thermal flexibility is analyzed in **Papers III** and **IV**.

3.1.4 Impact of electricity price volatility

A key aspect of the work is to study the impact of electricity price volatility on the operation and profitability of CHP plants. Scenarios for how the future Swedish electricity system could develop are obtained from the work of Göransson et al. [7] and provided as input to the dispatch optimization model. The scenarios consider the years 2030, 2040 and 2050, where the CO_2 cost successively increases. There are two types of scenarios for each year: with or without flexibility in sector-coupled electric loads, denoted "C" (with flexibility) and "NC" (without flexibility), respectively. The scenarios are described in more detail in **Paper III**.

The volatility index, VI, of an electricity price profile is introduced, defined as:

$$VI = \frac{\int_{t_1}^{t_2} (price(t) - average\ price)^2\, dt}{t_2 - t_1} \cdot \frac{1}{100} \qquad (2)$$

Figure 4 compares the average electricity price and volatility index of the electricity price scenarios, based on the operating period of the waste-fired plant. The average price decreases from 2018 to 2030, then gradually increases until 2050. The volatility index increases with time, as the shares of intermittent energy sources are increased; and is slightly higher in scenarios with flexibility in sector-coupled loads (C), due to long periods with alternating high and low electricity prices (see the electricity price profiles in **Paper III**).

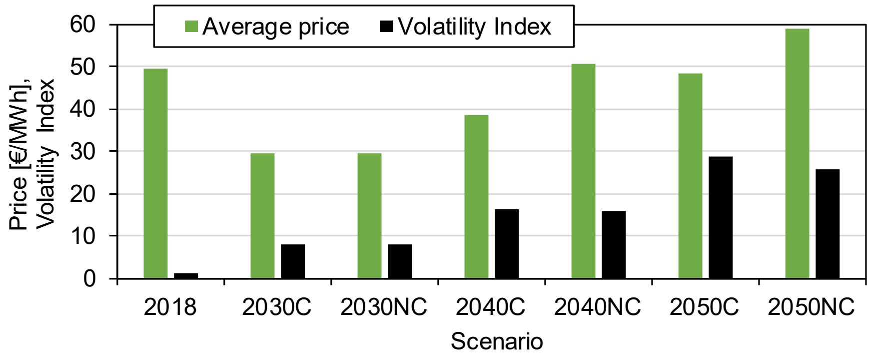

Figure 4. The average electricity price and electricity price volatility index during the operating period of the waste-fired plant, for the different electricity price scenarios. "C" = scenarios with flexibility in sector coupling, "NC" = scenarios without flexibility in sector coupling. Source: Paper III.

3.2 Reference CHP plants

Two combined heat and power plants are used as references in this work: a waste-fired plant and a natural gas-fired combined cycle plant. Thus, the most flexible and inflexible types of CHP plants are represented in the work. **Papers I-III** are based on models of the waste-fired reference plant, and **Paper IV** studies the combined cycle.

The waste-fired plant is a 48 MW_{el} CHP plant, located in Västerås, Sweden, and operated by Mälarenergi AB, as a base-load unit in the local municipal district heating system. The total annual heat production in Västerås amounts to some 1.8 TWh, with a peak load of around 630 MW. The waste-to-energy plant has a circulating fluidized bed boiler for steam regeneration. The boiler load range is 70-100% of full load, with a nominal capacity of 167 MW fuel. The plant configuration, with emphasis on the steam cycle, is shown in Figure 5a. The plant has extraction and backpressure condensers for district heating generation (Cond 1-2 in Fig. 5a), and two extractions for feed water preheating and deaeration.

The combined cycle plant is located in Gothenburg, Sweden, and is operated as a peak-load unit in the district heating network. The total annual supply of district heating in Gothenburg is around 4 TWh, with a peak demand of 1.2 GW. The combined cycle has a nominal capacity of 300 MW heat and 250 MW electricity, including three gas turbines with nominal power 43 MW (ISO conditions). The gas turbine load range is 30-100% of nominal capacity. The plant design is shown in Figure 5b. There are three parallel lines with one gas turbine, single-pressure heat recovery steam generator and supplementary firing burner each; and one steam turbine. District heating is extracted from the steam cycle condensers via one backpressure and one extraction condenser.

Both plants have a steam turbine bypass possibility, where the live steam can be condensed in a third condenser, producing additional district heating or being cooled by cooling water. The bypass is not used during normal operation. Both plants provide electricity to the Nordic day-ahead liberalized electricity market.

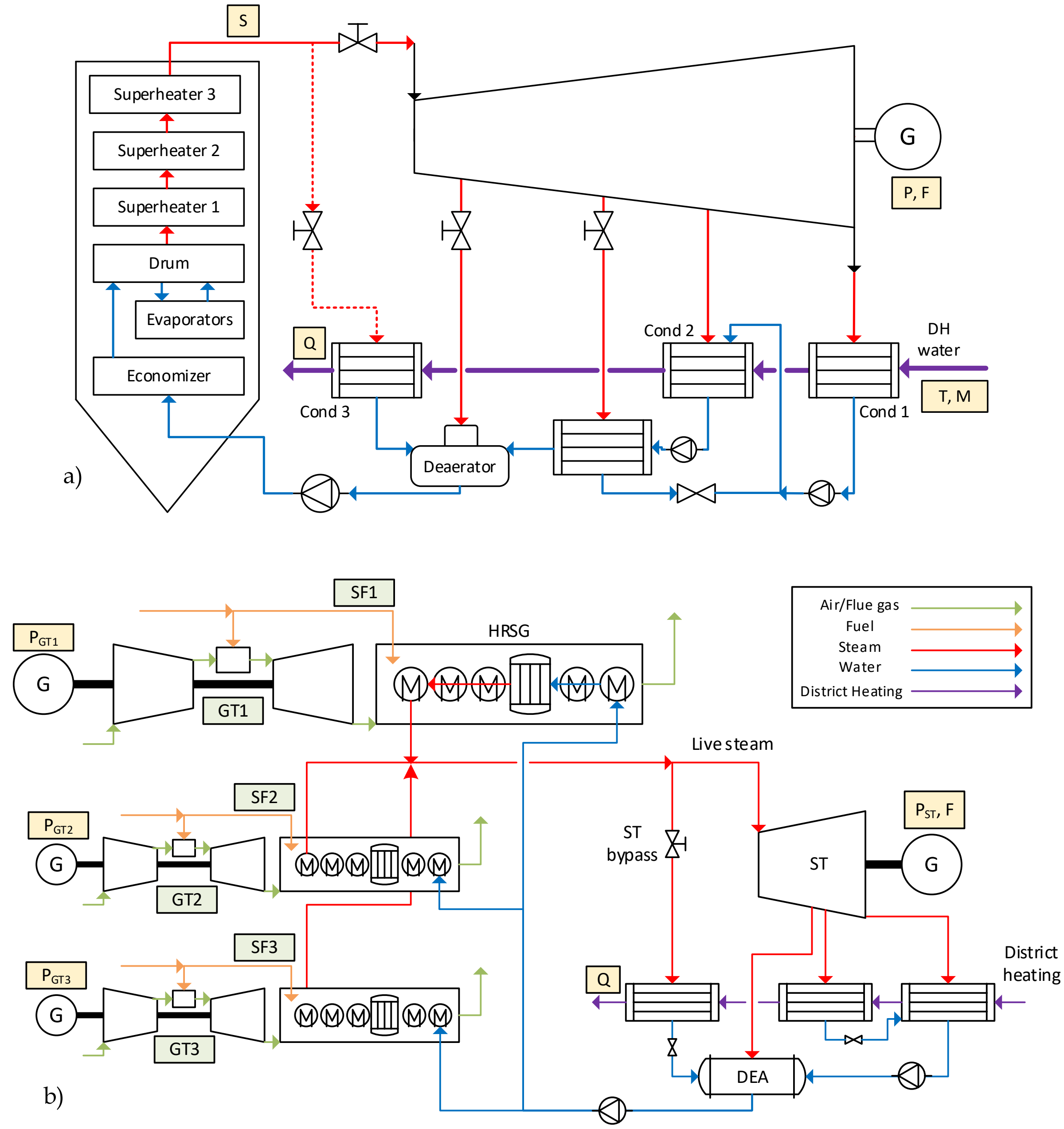

Figure 5. Process schematic of a) the waste-fired reference CHP plant, focusing on the steam cycle, and b) the gas turbine combined cycle reference plant. GT = gas turbine; SF = supplementary firing; HRSG = heat recovery steam generator; ST = steam turbine; DEA = deaerator; Cond = condenser. Letters in yellow boxes indicate the process variables of main interest for the work: P = electricity generation; Q = district heating generation; F = primary frequency response; S = live steam; T = district heating return temperature; M = district heating mass flow. Letters in green boxes represent fuel inputs.

4. Modeling

This chapter briefly introduces the modeling methods used in this work, including dynamic and steady-state process modeling where the models are validated with reference data from the two reference plants; and plant dispatch optimization modeling. The dynamic models are used in **Papers I, II** and **IV**, the steady-state models in **Papers II, III** and **IV**, and the optimization models in **Papers III** and **IV**.

4.1 Dynamic process modeling

Dynamic process models of the reference plants are developed in the modeling environment Dymola, with the modeling language Modelica, using the Thermal Power component library [49]. The models are based on physical equations with mass and energy balances. The models are developed based on the process schematics in Figure 5 and include control system structures for regulation of flows, temperatures and pressures. Two simplified examples of the model features are given here; focusing on a gas-two-phase heat exchanger and a steam turbine; while further details on the dynamic models of combined heat and power steam cycles are presented in **Paper I**.

The combined cycle heat recovery steam generators and the waste-fired plant's flue gas train are modeled with gas-two-phase heat exchanger components, according to Figure 6, with discretization and detailed geometry parametrization. The heat transfer from the hot flue gas to the water-side is governed by the heat transfer coefficients, *a*, of the gas phase, two-phase and pipe metal walls. For instance, the energy transfer between the wall and the fluid is given by Eq. 3. The heat transfer coefficients are calculated from correlations that depend on, e.g., the flow regime, pipe diameter, fluid and material properties. Eq. 4 gives the correlation for the convective heat transfer coefficient in the gas phase, based on the Nusselt number, *Nu*; thermal conductivity, λ; hydraulic pipe diameter, *d*; and *F* and *C*, which are correction and calibration factors. The correlation for water-side heat transfer coefficients is given by Eq. 5. Heat transfer through the metal wall is characterized by the wall thermal resistance, *R*, Eq. 6.

$$\dot{m}(h_{out} - h_{in}) = \alpha A\left(T_{gas} - T_{wall}\right) \quad (3)$$

$$\alpha = C\frac{F_a * Nu_0 * \lambda}{d_{hyd}} \quad (4)$$

$$\alpha_L = 0.023\, Re^{0.8}\, Pr_L^{0.4}\left(\frac{\lambda_L}{d_{hyd}}\right) \quad (5)$$

$$\frac{m_{wall} c_p dT}{dt} = \frac{2}{R_{wall}}(T_{wall,g} - T_{wall,steam}) \quad (6)$$

The steam turbine component is modeled in steps where the generated electricity is calculated based on the inlet and outlet enthalpies of the steam (Eq. 7). The inlet enthalpy is a calculation input, while the outlet is computed from a specified isentropic efficiency (Eq. 8). Adjustments are made for the isentropic efficiency in the wet steam region, using the Baumann coefficient, β, according to Eq. 9. Steam turbine part load performance is also accounted for, with Stodola's law and the flow area coefficient, K_t (Eq. 10) [50].

$$P_{step} = \eta_{mech}\dot{m}(h_{in} - h_{out}) \quad (7)$$

$$h_{out} = h_{in} - \eta_{is}(h_{in} - h_{is}) \quad (8)$$

$$\eta_{is,wet} = \eta_{is,dry} - \beta(1 - x) \quad (9)$$

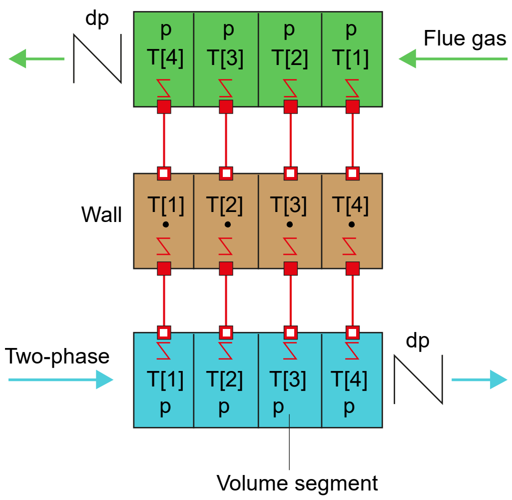

Figure 6. Illustration of the heat transfer and pressure drop modeling in gas-two-phase heat exchangers, placed in the flue gas pass of the waste-fired plant and the heat recovery steam generators in the combined cycle. T = temperature; p = pressure. Source: Paper I.

$$K_t = \dot{m}\sqrt{\frac{RT}{p_1^2 - p_2^2}} \tag{10}$$

Supplementary firing is modeled as a heat source with an input value for the load, connected to a flue gas duct component. Gas turbines are modeled as static components, in which the electricity production, exhaust flow and temperature depend on the load level and ambient temperature, according to characteristic curves provided by the manufacturer. A static representation is justified by the short timescales of the gas turbine compared to the heat recovery steam generator [51].

4.1.1 Dynamic model validation

The dynamic process models are validated with steady-state and transient data from the two reference plants, respectively. Here, examples of the validation with transient data are given. The results from validation with steady-state operational data can be found in **Paper I** and **Paper IV**. Input trajectories are provided to the models for the thermal input loads, expressed as flue gas temperatures and flows, as well as district heating flow and return and supply temperatures, and controller set points. The simulated outputs are compared to the reference measurements. For example, Figure 7 plots the simulated response for live steam flow in a) the waste-fired steam cycle, and b) one of the three heat recovery steam generators in the combined cycle; together with the measured flow. Further transient validation results for the waste-fired plant and combined cycle are given in **Paper I** and **Paper IV**. The simulated values follow the trends of the measurement signals well. For the purpose of this work, the models are, thus, considered adequate representations of the reference plants.

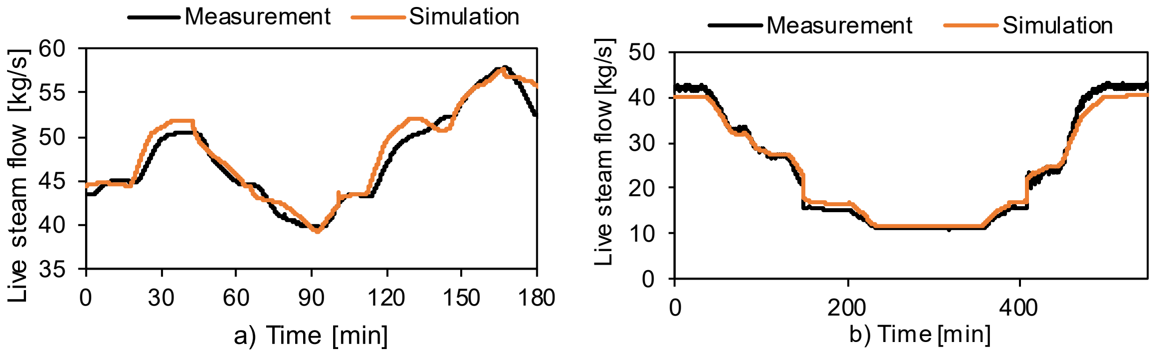

Figure 7. Transient validation simulation responses (orange) vs reference measurements (black) for live steam flow, for a) the waste-fired plant; and b) one heat recovery steam generator in the combined cycle. Source: Paper I and Paper IV.

4.2 Steady-state process modeling

Stationary process models of the reference plants are developed in the modeling environment EBSILON Professional. The models consist of process components according to Figure 5. The steam cycles include a turbine model based on Stodola's law, accounting for part load performance; condensers where district heating is generated; deaerators and feed water pumps. In the waste-fired plant model, the boiler is represented by a steam generator component. In the combined cycle model, the steam generation takes place in the heat recovery steam generator consisting of a series of heat exchangers (economizer, evaporator, superheaters with intermediate steam attemperators), similar to the dynamic model. Supplementary firing is represented by a duct burner component. Gas turbines are modeled according to the description in Section 4.1.

The model inputs include load levels for the steam generator, gas turbines and supplementary firing burners; and district heating mass flow and temperature boundaries. Calculated outputs are obtained for process parameters, such as temperatures and pressures at various points in the processes, and electricity and district heating generation. The steady-state process model validations are presented in **Paper III** and **Paper IV**. Deviations from reference values are generally within 5%. The validated models are then adapted to simulate the process performance of the five steam cycle operational modes introduced in Section 3.1.2.

4.2.1 Linear surrogate process models

The steady-state process models are simplified to linear surrogate models using regression analysis. The surrogate models are based on simulated outputs from the EBSILON models for each of the five operational modes and different load levels. From linear regression, coefficients are estimated that describe the impact on response variables from input variable variations. Surrogate models on the form given by Eq. 11 are obtained for the waste-fired plant, where the production of electricity (*P*), district heating (*Q*) and primary frequency response (*F*) are functions of the steam flow (*S*), district heating temperature (*T*) and mass flow (*M*), see the notation in Figure 5. The coefficients, β, are specified for each response variable and operational mode. Similar equations are computed for the combined cycle bottoming steam cycle (Eq. 12), where the produced outputs depend on the load levels of the three gas turbines (GT) and supplementary firing (SF) burners. The gas turbine fuel consumption and electricity generation are functions of gas turbine load and inlet air temperature (Eq. 13 and 14).

$$P_{ST}, Q, F(t) = \beta_S S(t) + \beta_T T(t) + \beta_M M(t) + \beta_0 \tag{11}$$

$$P_{ST}, Q, F(t) = \beta_{GT} \sum_{GT} \left(Load(t, GT)\beta_{GTLoad} + \beta_{0,GTLoad} \right) + \beta_{0,GT} + \beta_{SF} \sum_{SF} Load(t, SF) + \beta_{0,SF} \tag{12}$$

$$Fuel(t) = Load(t)\beta_{Load} + T_{air}(t)\beta_{Temp} + \beta_0 \tag{13}$$

$$P_{GT}(t) = Load(t)\beta_{Load} + T_{air}(t)\beta_{Temp} + \beta_0 \tag{14}$$

4.3 Dispatch optimization modeling

Mixed integer linear programming models are developed for optimization of the combined heat and power plant dispatch, using the modeling environment GAMS. Figure 8 shows an overview of the models. The model objective is to maximize the plant revenue from sales of electricity and primary frequency response, while supplying an hourly district heating demand. Thermal flexibility can be used (if available) to shift the production of district heating in time, to better match power market conditions. The objective function is given by:

$$\max R = \sum_{t} (C_{el}(t)P(t) + C_{frq}(t)F(t) - (C_{fuel} + C_{CO2})Fuel(t) - C_{start} n_{starts}) \tag{15}$$

where R is the total revenue of the modeling period; C is the cost/price for electricity, primary frequency response, fuel, CO_2 emissions and start-up; P, F and $Fuel$ are the production of electricity and frequency response and fuel consumption, while n_{starts} is the total number of starts (gas turbines or waste-fired boiler). No price is associated with sales of district heating since the delivery is a specified requirement, although district heating production will, of course, generate revenue in practice.

The decision variables that the model optimizes are the load levels of the steam generator (waste-fired), or the gas turbines and supplementary firing (GTCC), as well as the selection of steam cycle operational mode (CHP/HOB/FRQ/COND/CFQ). Constraints are formulated to ensure that the plant dispatch follows feasible operating patterns. Logic constraints make sure that only one steam cycle mode is used at a time. Detailed model formulations are available in **Paper III** and **Paper IV**.

The model inputs are: the linear surrogate models described in Section 4.2.1, that represent the plant performance and feasible operating regions; hourly price profiles for electricity [7,52] and frequency response [53], hourly district heating demand and air temperature profiles based on reference plant data, cycling cost [7], CO_2 cost [7,54] and fuel cost [7,55]. Furthermore, specifications are given for the level of thermal flexibility that the plant has access to. Outputs include hourly values for the plant revenue, the optimal mode of steam cycle dispatch, and the fuel input loads. The sensitivity of results to variability in cost data is analyzed, as described in **Paper III** and **Paper IV**.

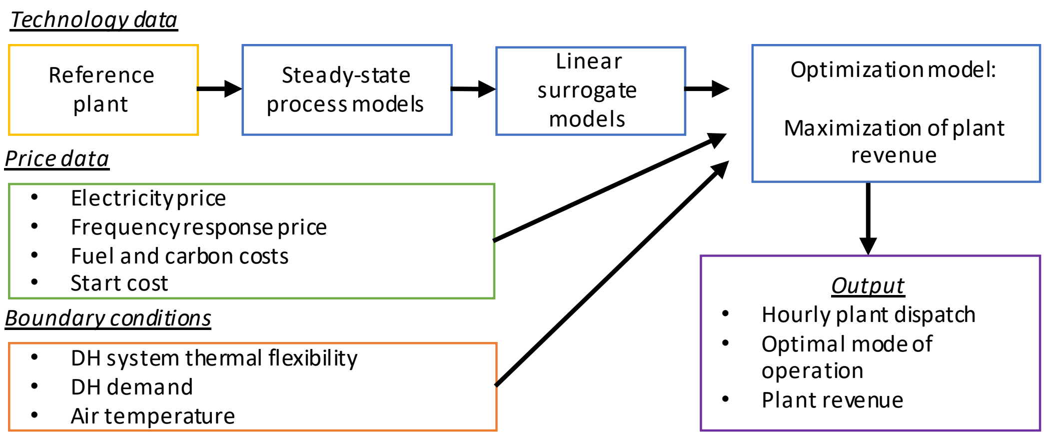

Figure 8. Overview of the dispatch optimization models, with inputs, outputs and links between process models.

5. Selected results and discussion

This chapter provides a summary of the main results of the work in this thesis, based on the findings presented in the appended papers. The chapter is divided into three sections that concern 1) the technical potential for combined heat and power plant flexibility; 2) the impact on CHP operational patterns from operational, product and thermal flexibilities; and 3) the impact on plant revenue from the three flexibility measures, in different electricity market contexts.

5.1 Technical potential of combined heat and power flexibility

This section presents the technical potential for flexibility, in terms of magnitude of load range and rate of load change, with and without product flexibility. The two reference plants are compared and the factors that differentiate their respective potentials for flexibility are discussed.

5.1.1 Product flexibility and load range expansion

The combined heat and power product flexibility enables a load range expansion compared to condensing plants, by varying the product ratios. Figure 9 visualizes this load range expansion obtained for a) the waste-fired and b) the combined cycle steam cycles when implementing product flexibility. The colored lines indicate operation between minimum and full load in the five modes. The blue lines represent conventional cogeneration of heat and electricity with a fixed power-to-heat ratio. The feasible operating regions, marked by the dashed lines, are significantly enlarged with product flexibility compared to conventional operation, for both plants. Operation in condensing steam cycle modes has the potential to increase the electricity generation at full load with 27% and 39% for the waste-fired and GTCC plants, respectively. The corresponding numbers for increased heat production potential are 44% and 42%. The variable product mix may also decrease outputs down to 0 MW.

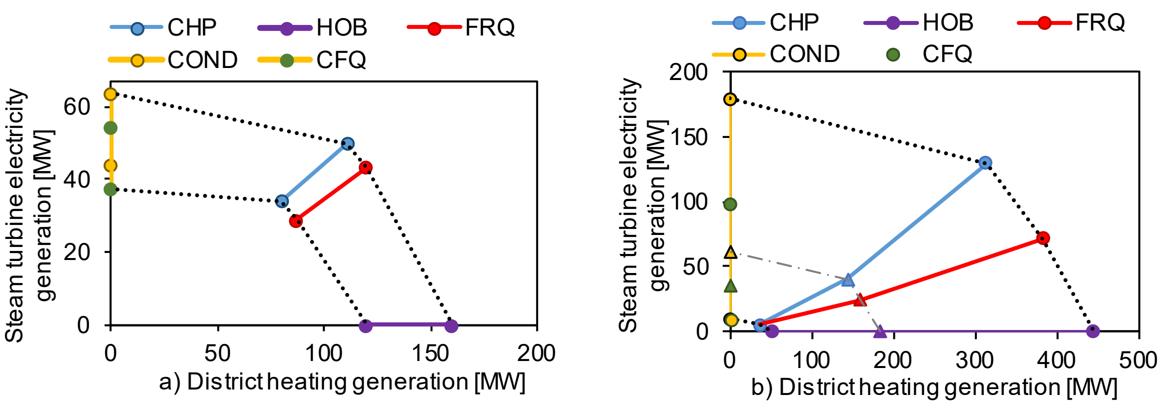

Figure 9. The load range expansion of the a) waste-fired and b) combined cycle steam cycles, obtained from product flexibility with steam cycle operational modes, producing different amounts of electricity, heat and primary frequency response. CHP = combined heat and power generation (blue); HOB = steam cycle heat-only generation (purple); FRQ = CHP with frequency response (red); COND = condensing mode, electricity-only generation (yellow); CFQ = COND with frequency response (green dots). Dashed lines mark the feasible operating regions. Triangles mark GTCC operation at nominal gas turbine load without supplementary firing. Note the different scales on axes. Source: Paper III and Paper IV.

GTCC plants are, based on the argumentation in Section 2.2, traditionally designed for flexible operation to a larger extent than waste-fired plants. In terms of static potential, the GTCC reference plants obtains its comparatively large load range expansion from the possibility to use supplementary firing: without supplementary firing the GTCC load range would be bounded by the vertices given by the triangles, marking full load gas turbine operation without supplementary firing, which would decrease the GTCC feasible operating area significantly, to a MW full load level comparable with the waste-fired plant. However, owing to the three parallel lines of gas turbines and HRSGs (Figure 5), the combined cycle has a lower minimum load level than the waste-fired plant (approximately 13% of GTCC full load compared to 70% CFB load), that places the lower rims of the enclosed area closer to the origin. Thus, the GTCC plant has, as expected, a stronger plant level potential for flexible operation, considering the load span of electricity and heat generation; but economic and system related factors impact how this potential is used, as discussed in Sections 5.2-3.

5.1.2 Dynamics of operational flexibility and ramp rates

This section compares the potential for (rapid) steam turbine load change in the waste-fired steam cycle and combined cycle plant, using traditional operating strategies - control of thermal input (**Paper I** and **Paper IV**) - and steam flow regulation via the steam turbine bypass, enabled by product flexibility (**Paper II**). Figure 10 presents the dynamic simulation steam turbine electricity generation responses for load decreases induced by changes in flue gas energy flow (waste-fired plant), supplementary firing load, gas turbines, or steam turbine bypass control. One ramp rate example is shown for each type of load change. For further ramp rate simulation responses, see **Paper I, Paper II** and **Paper IV**.

The responses from waste-fired and supplementary firing thermal input changes follow similar trends, with the electricity generation output following the linear ramp rate load reduction. Both of these responses are comparatively slow to completely settle at the new steady-state value, but 95% settling is reached within 17 minutes for the waste-fired case, and 34 minutes for the supplementary firing example, having a load reduction twice as large as the waste-case. The gas turbine load change responses show a different trend, with a sustained steam turbine electricity generation at the initial level before the electricity generation approaches the lower level. This response pattern could be related to the increase in gas turbine exhaust temperature observed for gas turbine load changes (see Figure 7a in **Paper IV**), causing the live steam enthalpy to decrease slower than for the supplementary firing load reduction, where the flue gas temperature strictly decreases with load.

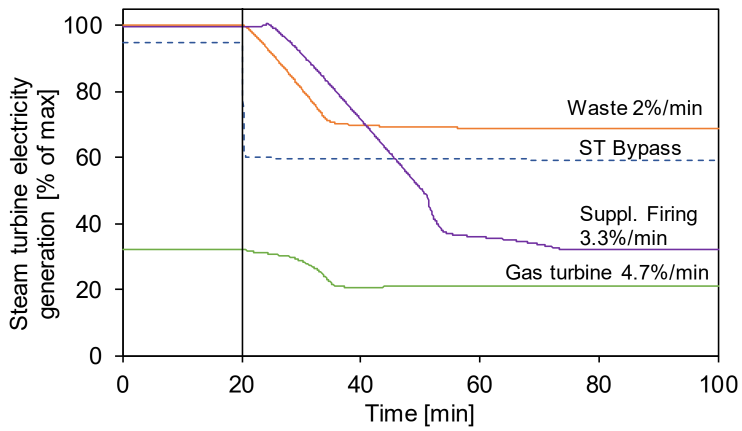

Figure 10. Steam turbine electricity generation responses when the thermal input to the steam cycle decreases from full to minimum load, for the waste-fired steam cycle (orange), gas turbine (green) and supplementary firing (purple) load changes. The dashed line represents the response from steam flow regulation (steam turbine, ST, bypass) in the waste-fired steam cycle. The ramp rates are indicated by the labels, in load-%/min of nominal capacity. The ramp is initiated at time = 20 minutes, indicated by the black vertical line. Source: Papers I, II and IV.

The steam turbine response times are in the range of 15-55 minutes for thermal input changes, depending on the magnitude of load reduction and ramp rate, which could be sufficient for participation in hourly energy-only markets. In comparison, the response time for the steam turbine bypass option is within 3 minutes (see Figures 4 and 5 in **Paper II** for more details). Utilizing product flexibility with the steam turbine bypass could, thus, lead to significantly increased response rates for the steam cycle electricity generation compared to the corresponding load reduction from thermal input; and could give the plant a potential for participation in grid service markets. Furthermore, a coordinated control strategy involving both a reduction in thermal input load and steam flow regulation could be of interest for making rapid load reductions intended for extended durations. However, bypassing the steam turbine does not only reduce the electricity generation, it also increases the production of district heating, as the live steam is condensed (see Figure 5 for process schematics). The increased heat delivery must be managed within the district heating network to use such an operating strategy [56].

5.2 Impact on operational patterns of plant and system level flexibilities

The opportunity to operate the steam cycle with product flexibility and with thermal flexibility in the district heating network will impact the optimal plant operating patterns. This section discusses the utilization of product flexibility over an annual operating season with and without plant and system level flexibilities; and the tendency to dispatch the plant based on heat demand and/or electricity price.

5.2.1 Utilization of product flexibility and steam cycle modes

Figure 11 shows the optimal distribution of operational hours between the five steam cycle modes for a) the waste-fired and b) the combined cycle plants. If product flexibility is not implemented, the plant dispatch will, of course, consist of CHP-mode operation only. When product flexibility is available, but not thermal flexibility, the dispatch of the combined cycle changes, to mainly include HOB (40%) and FRQ (50%) modes; while the waste-fired steam cycle dispatch is largely unaffected (98% CHP). FRQ mode is favored at times when the frequency response price exceeds the electricity price.

The difference between the two plant dispatches is related to fuel costs. The combined cycle has higher operational costs than the waste-fired plant, since natural gas is more expensive than waste. It is therefore profitable for the GTCC plant to reduce the natural gas consumption, by utilizing the HOB mode to maximize the heat production per fuel combusted (i.e. allowing reduced fuel load while maintaining the heat production, see Figure 9b), seeing as heat delivery is a strict plant requirement in the model. The waste-fired plant does not have the same incentive to reduce fuel expenses; rather, it is profitable to increase the combustion of zero-cost waste and plant utilization with condensing operation. However, the heat demand must still be met every hour, which is not feasible with condensing modes unless thermal flexibility is implemented. Adding thermal flexibility is, thus, a requirement to unlock the operational potential of product flexibility for the waste-fired plant and leads to operation in condensing modes up to 20% of hours. For the combined cycle, adding thermal flexibility shifts the ratio of HOB/FRQ slightly.

If the average electricity price and electricity price volatility increases (2030C), the combined cycle dispatch shifts towards a larger share of CHP operation, driven by the increased number of hours with high electricity prices that favor combined electricity and heat production using the CHP mode. During low-price hours, the HOB or FRQ modes are still selected, with reduced or zero electricity output. For the waste-fired plant, the share of CHP-operating hours instead decreases in favor of frequency response delivery, which is more profitable during the increased number of hours with low electricity prices. FRQ operation also yields slightly increased heat production (Figure 9a), that can be stored and load-shifted to enable further use of the condensing modes, maximizing the electricity production during high-price hours.

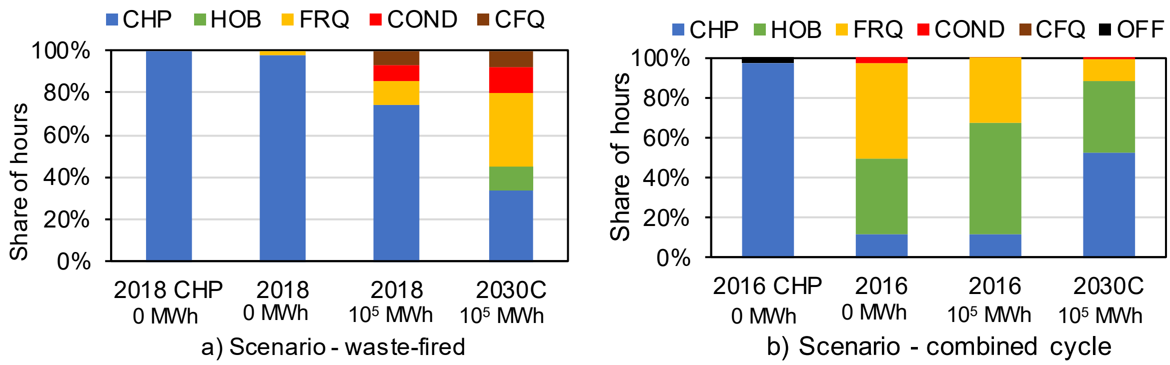

Figure 11. The optimal distribution of operational hours between the steam cycle operational modes enabled by product flexibility, for a) the waste-fired steam cycle; and b) the combined cycle steam cycle. Two electricity price scenarios are compared, where the availability of product and thermal flexibilities is varied. CHP = operation without product flexibility. The thermal flexibility is given in MWh for each case. Source: Paper III and Paper IV.

The optimal steam cycle dispatch is, thus, strongly dependent on the cost structure of the plant. Plants with a low fuel cost can benefit from thermal flexibility that enables condensing operation at times with high electricity prices, increasing the income and expanding the operational hours from the traditionally limiting heat demand; whereas plants with high fuel expenditures utilize heat-only generation (enabling maintained heat production for a reduced fuel consumption) to provide the required heat to the lowest possible cost, thereby increasing the revenue.

5.2.2 Electricity production patterns

Figure 12 plots the optimal combined cycle electricity generation profile for the 2030C electricity price scenario, with a) no product flexibility or thermal flexibility; and b) product flexibility and 100 000 MWh thermal flexibility. The time period plotted corresponds to the plant's heat generating season. Obviously, if the plant does not operate neither with product flexibility nor thermal flexibility, the plant must operate with a fixed power-to-heat ratio and the electricity generation follows the heat demand profile. With variable product ratios and thermal flexibility in the district heating network, the heat production can be shifted in time, and the plant operation is instead dictated by the electricity price profile. If product flexibility is available but not thermal flexibility (not shown), the optimal combined cycle electricity generation will be influenced by both the heat demand profile and the electricity price: when the electricity price is low compared to the fuel cost, heat-only operation of the steam cycle is utilized to decouple heat and electricity production, to reduce the fuel expenditures (Section 5.2.1).

With enhanced flexibility, the optimal operating strategies of CHP plants may, thus, shift from heat-following to electricity-following. This might potentially lead to new regimes of dynamic operation, with a transition from transients associated with the comparatively slow dynamics of the district heating network, to the more rapid changes in price signals of the electricity market. The coordinated control strategy introduced in Section 5.1.2 could be of value in such contexts, with fast responses in electricity generation; both for thermal input changes, and for transitions between steam cycle operational modes. The relative value for the plant of making rapid load changes to follow variability in electricity market price signals is discussed in Section 5.3.2.

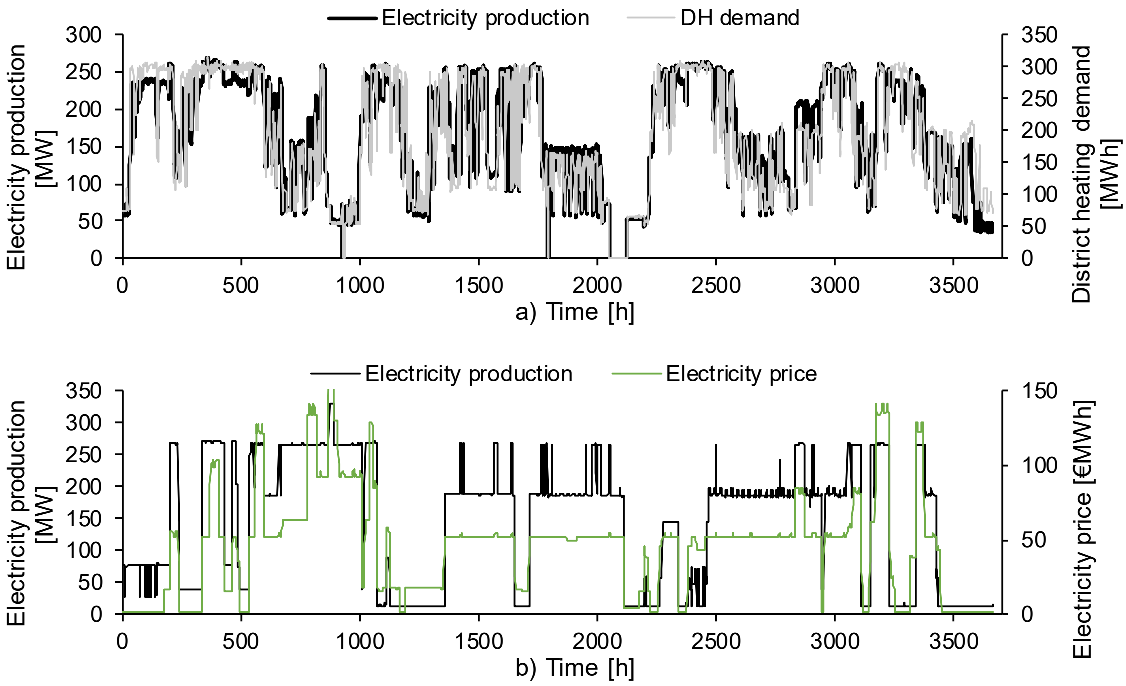

Figure 12. Optimal electricity production profiles (black) for the combined cycle in the 2030C electricity price scenario with a) no product flexibility or thermal flexibility; and b) product flexibility and 100 000 MWh thermal flexibility. The grey line in a) plots the district heating demand, and the green line in b) shows the electricity price. Source: Paper IV.

5.3 Economic potential of plant and system level flexibilities

The economic benefits of plant and system level flexibilities are discussed in this section. The first subsection considers the impact on revenue of product and thermal flexibility in different electricity price contexts, and the second subsection evaluates the value for the plant of operational flexibility in terms of ramp rate.

5.3.1 Impact on revenue of product and thermal flexibility

Having the possibility to adapt the combined heat and power plant production to market conditions will lead to an increased plant revenue. Figure 13a gives the increase in annual plant revenue per installed electric capacity for the waste-fired plant (solid lines) and the combined cycle (dashed lines) when implementing thermal flexibility, for different electricity price scenarios; b) gives the additional increase in revenue from product flexibility; and c) plots the total increase in revenue from product and thermal flexibility given by the sum of a) and b).

Without product flexibility, a thermal flexibility of at least 1 000 MWh is needed for the plants to obtain a significant increase in annual revenue, but this benefit increases with the level of thermal flexibility; reaching up to 57 k€/MW and 28 k€/MW for the combined cycle and waste-fired plant, respectively. The impact on the revenue from thermal flexibility also increases with electricity price volatility in future scenarios (Figure 4): the electricity price fluctuation is a main driver for the plant to shift the heat production in time, using the thermal flexibility, to plan operation based on the electricity market conditions (Section 5.2.2).

As product flexibility is added, different trends for the impact on revenue are noticed, relating to the cost structure and shift in operating strategies for the respective plant type. For the waste-fired plant, the plant revenue increases further with product flexibility, up to 60 k€/MW, especially for high levels of thermal flexibility; indicating that there is a synergy between product and thermal flexibility. As described in Section 5.2.1, waste is a zero-cost fuel in the model that makes plant operation profitable as long as electricity prices are not lower than the fuel cost. Condensing operation, enabled by product flexibility, is thus economically favorable as it increases the plant utilization, production and revenue. A prerequisite for condensing operation is that thermal flexibility is available to store or supply heat, and therefore the plant revenue, and opportunity for electricity-only production, increases with the level of thermal flexibility. However, the increase in revenue starts to level off above thermal flexibilities of 10 000 MWh, which might indicate that the plant can be operated with full utilization (at maximum capacity) at a thermal flexibility lower than 10 000 MWh, rendering further increases in production infeasible even if the level of thermal flexibility is increased.

For the combined cycle, the opposite trend is observed: the additional revenue increase from product flexibility decreases from 10-40 k€/MW to 5-10 k€/MW for a thermal flexibility of 100 000 MWh. The reduction in economic benefit from product flexibility for the GTCC relates to the shift in operating patterns that is enabled from thermal flexibility. At low levels of thermal flexibility, the CHP plant operating profile cannot deviate from the heat demand profile to any large extent. In this context, product flexibility is valuable for the plant, to reduce operating costs by prioritizing heat-only generation from the steam cycle (Section 5.2.1). If the level of thermal flexibility is high (>1 000 MWh), the plant operation is instead adapted to match the electricity price (Section 5.2.2), where the main value lies in the load-shifting of heat production, rather than operating using different modes. Hence, for the combined cycle, with a high fuel cost, there is a competition between product and thermal flexibility, instead of synergy.

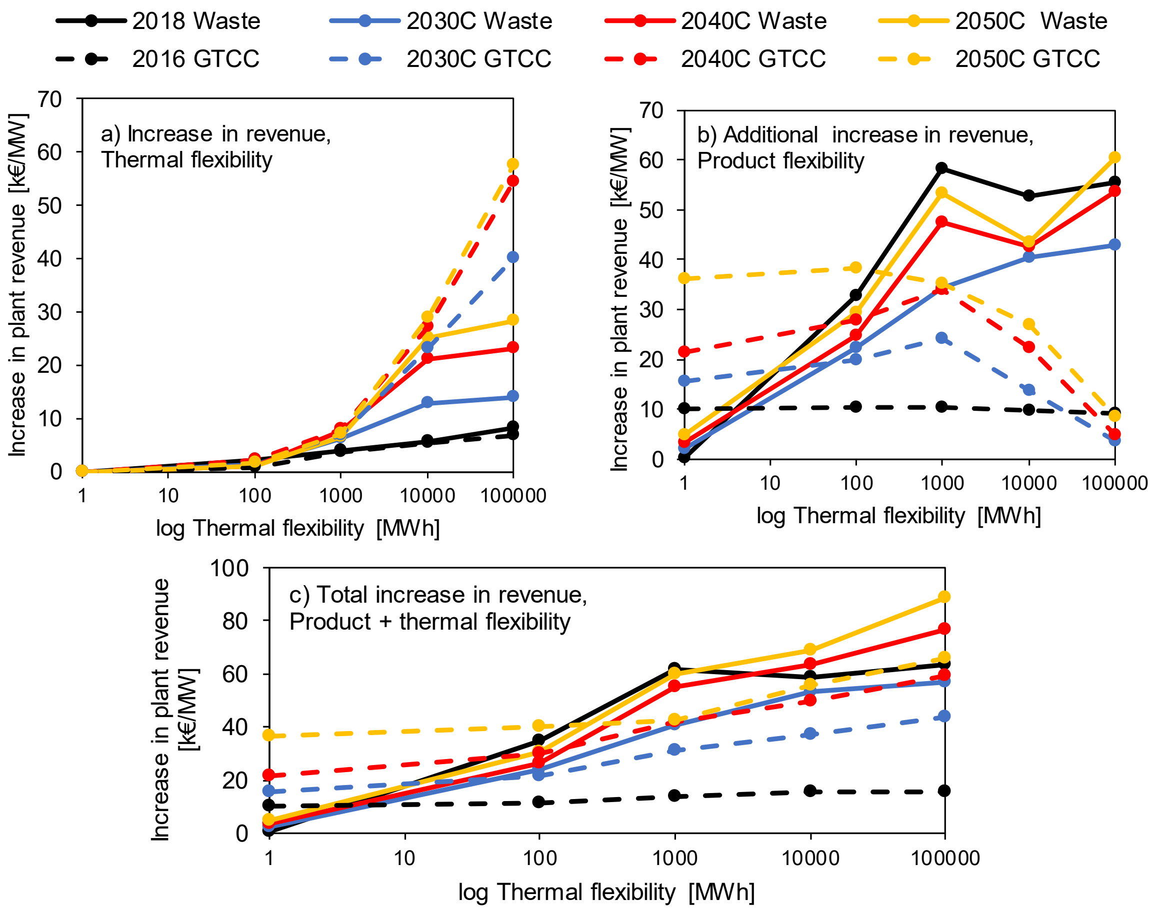

Figure 13. a) The annual plant revenue increase per installed electric capacity from thermal flexibility, for different electricity price scenarios. b) The additional increase in plant revenue from product flexibility. c) The total increase in revenue from product and thermal flexibility is given by the sum of a) and b). Solid lines represent the waste-fired plant, and dashed lines the combined cycle (GTCC). Note the logarithmic scale on the x-axes. Source: Paper III and Paper IV.

For both plant types the annual revenue increases with both types of flexibility measures (Fig 14c), although the total increase in revenue per installed electric capacity is generally larger for the waste-fired plant (up to 88 k€/MW) than for the combined cycle (up to 66 k€/MW). For the waste-fired plant, the economic benefit might be attainable for current electricity market conditions (up to 63 k€/MW) thanks to the increased plant utilization. For the GTCC plant, current market conditions do not significantly incentivize flexibility measures, in particular thermal flexibility; increased levels of variable electricity generation are needed for the combined cycle to benefit more from flexibility.

5.3.2 Impact on revenue from dynamic operational flexibility and ramp rate

In the Nordic energy-only market, the electricity price changes in steps on an hourly basis, where the price is set based on bids from actors that trade electricity. Thermal power plants that have made bids to increase or decrease the electricity production will, however, generally have a delay in the electricity generation ramp compared to the step-change in price, due to thermal inertia in the plant. The response delay can be seen as a loss in revenue for the plant (Eq. 1) that also cause unbalance in the power system but might be minimized by increased ramp rate.

Figure 14 shows the estimated annual loss in revenue comparing static (instantaneous load changes) and dynamic operation of the GTCC-CHP plant in the different electricity price scenarios, for three ramp rates of gas turbines and supplementary firing. Compared to the revenue increase from product and thermal flexibility (ranging from 10-90 k€/MW, Figure 13) the impact on the revenue from dynamic operational flexibility is in most ramp cases small (<5 k€/MW), and decreases with increased ramp rate. The largest losses in revenue are obtained for the 2030-2050 scenarios, which also have the most significant revenue increase in Figure 13. There is, thus, a trend that the value of fast ramping will increase with electricity price volatility for the GTCC plant, although this value is still relatively low from a plant perspective.

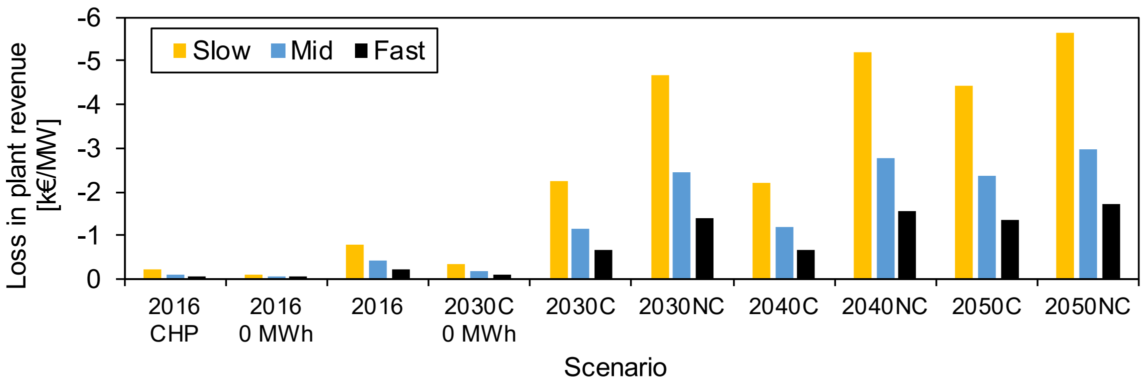

Figure 14. The estimated loss in annual plant revenue, comparing dynamic and static (instantaneous change) plant electricity production for the GTCC-CHP plant (Eq. 1). Three cases are compared where the ramp rates of supplementary firing and gas turbines are varied: slow = 0.8 and 1.2 %/min (yellow); mid = 1.7 and 2.3 %/min (blue); fast = 3.3 and 4.7 %/min (black), respectively. Product and thermal flexibilities are available unless otherwise indicated: CHP = operation without product flexibility; 0 MWh = operation without thermal flexibility. Source: Paper IV.

It is also observed that the cases without thermal flexibility (denoted CHP or 0 MWh) have the smallest economic impacts of the scenarios (<0.4 k€/MW). This is explained by the low number of steep ramps in these cases (see Figure 15 in **Paper IV**); without thermal flexibility, the plant production must follow the heat demand profile hour-by-hour. The district heating network has, in general, slow dynamics on a diurnal basis, with slow ramping requirements. With thermal flexibility, the electricity production pattern is adjusted to instead follow the electricity price profile, where the increased price volatility of 2030-2050 scenarios (Figure 4) cause steep ramps to occur with a higher frequency for the combined cycle.

For the waste-fired plant, the corresponding loss in revenue between static and dynamic operation would approach 0 M€, because optimally no ramp events occur during the year, other than for scheduled maintenance stops (see Figure 14 in **Paper III**). The lack of ramping comes from the low fuel cost of waste (0 €/MWh in the model), which makes plant operation at full load profitable as long as the product price signals are positive compared to operational expenditures.

6. Conclusion

This thesis provides an analysis of the relative value for combined heat and power plants to operate with increased levels of flexibility, in Swedish energy system contexts with volatile electricity prices caused by high levels of non-dispatchable generation (e.g. wind power). The technical and economic potential for flexibility in two types of heat-driven CHP plants (waste-fired and combined cycle) are assessed with the modeling framework developed, comprising steady-state, dynamic and optimization models. The results point at the different levels of flexibility that are technically feasible in the two CHP plant types and highlights the economic impact for the plants of operational, product and thermal flexibilities.

Both the combined cycle and the waste-fired plant are, from a technical point of view, able to operate flexibly to vary their electricity and heat generation. Electricity generation may be controlled by the thermal input from fuel combustion (operational flexibility), or by varying the ratio between products (product flexibility). Product flexibility expands the feasible operating regions of the plants, with an increased number of electricity and heat generation levels made available compared to that of operational flexibility only. Electricity generation at full load may be increased by 27% and 39% for the waste-fired and GTCC plants, respectively; and the heat generation by 44% and 42%. However, the plant level flexibility is, although expandable, limited by minimum load levels, especially the waste-incineration boiler that has a minimum load of 70% of full load compared to 13% for the combined cycle plant.

Dynamic simulation indicates that steam turbine electricity generation responses for load changes can be achieved within an hourly timescale, applicable to energy-only markets, or even within minutes if thermal input load changes are coordinated with steam turbine bypass operation; combining operational and product flexibilities. However, increasing the ramp rate and electricity generation response time will have a marginal impact on plant annual revenue (<6 k€/MW), especially for the waste-fired plant that generally (and optimally) does not operate with boiler ramping.

A significantly larger economic benefit for the plant can be obtained from product and/or thermal flexibility measures, up to 90 k€/MW increase in annual revenue. Depending on the CHP plant cost structure (especially with regard to fuel cost), these flexibilities increase the plant revenue by providing different functionalities. For the combined cycle, the increase in revenue comes from a reduction in consumption of expensive fuel, made possible by product flexibility and heat-only operation of the steam cycle, during 40-50% of operational hours. For the waste-fired plant, the fuel cost is low and not a limitation for profitability; instead, the economic benefit is obtained by expanding the plant operation outside the required district heating delivery, by operating the steam cycle in condensing modes up to 20% of the operational hours.

For the waste-fired plant, thermal flexibility in the district heating system is a necessity to utilize the product flexibility, and product and thermal flexibility work in synergy to increase the plant revenue. For the combined cycle, thermal flexibility reduces the value of product flexibility, by causing a shift in operating strategy from heat-following to electricity-following that reduces the utilization of steam cycle modes. As a general trend, the increase in plant revenue from flexibility grows with the electricity price volatility expected in future energy system scenarios; but the economic benefit is small for the low price volatility of the current system settings.

In sum, flexibility is technically possible and valuable for both types of combined heat and power plants studied in this work. The results obtained are highly connected to, and influenced by, the specific energy system context in which the plants operate; in this case Sweden, where CHP plants are traditionally heat-driven and designed accordingly; but the modeling framework developed can be used to expand the analysis also to different energy system settings.

6.1 Future Work

Based on the key outcomes of the thesis, new research directions can be pursued to further the understanding of combined heat and power flexibility and facilitate practical implementation of concepts.

6.1.1 Interactions between the CHP plant and district heating system

A key assumption that has been made in this work is that the heat demand from the CHP plant will remain at current levels in the future. This may potentially change with the future development of the electricity system and improved flexibility of CHP plants. For instance, the possibility to operate the CHP plant's steam cycle in condensing or heat-only modes could have benefits, not only for the plant, but also for the district heating system. Increased heat delivery from a CHP plant, enabled by operation in HOB mode, could replace heat production from expensive peak load units at times when the heat demand is large. Thermal flexibility could further enhance the system benefit, by decoupling heat production from the demand to allow electricity-following operation of CHP plants; which could be utilized by, and have a value for, all units in the district heating system and not only one plant as studied here. Product and thermal flexibility may, thus, have a significant impact on the dispatch of the district heating system as a whole and could lead to new operational regimes for CHP plants. Opportunities to expand the plant heat delivery by integration with new heat-intensive processes, such as carbon capture installations or production of synthetic biofuels, could also be of interest to study.

The relative size of the CHP plant compared to the district heating system could also be an important factor to consider in further analyses. Small district heating systems that only have one CHP plant may have limited opportunities to operate the plant flexibly with regard to the electricity market, as the system depends on heat delivery from the plant. Additionally, investments in thermal flexibility that would facilitate flexible CHP dispatch (e.g. a hot water accumulation tank) could be challenging for small district heating networks. Larger networks with multiple CHP plants or heat generation units would likely have stronger incentives and benefits to improve plant and system flexibility.

6.1.2 The CHP plants' role as variation management in the electricity system

Although the CHP plant interaction with the district heating system has traditionally been the main factor to consider for the plant dispatch, seeing as heat is the main product; the future development of, and need for variation management in, the electricity system may gain in importance when planning the plant operation. On a national level, on-demand electricity production (or reduced production) from CHP plants could be a key contribution to the electricity supply-demand balancing problem, as well as provide grid stability. In the future Swedish energy system context, it may happen that thermal CHP plants are the main dispatchable generation available in the system, considering the potential phase-out of nuclear power. However, the current electricity production from CHP plants amounts to approximately 10% of the total annual production in Sweden, and might therefore be of limited, although important, magnitude.

On a city level, the electricity generation contribution from CHP plants may be more tangible. For example, the combined cycle reference plant studied in **Paper IV** has the capacity to provide approximately 30% of the city's electricity demand on its own; a non-negligible share. Given that electricity demand in cities may increase in the future, for example from electrification of transport and other traditionally fossil-based processes, while the electricity transmission system capacity is limited and slow and costly to expand, the importance of local electricity generation grows. CHP plants may play a key role in such contexts, providing multiple energy system services.

Thus, there are several perspectives from which CHP plant flexibility and electricity generation could be viewed and optimized: 1) the plant perspective, with maximization of the plant revenue; 2) the district heating system perspective, with cost minimization of heat production; 3) the local electricity system perspective, with security of electricity supply; and 4) the national electricity system perspective, with integration of large-scale non-dispatchable power generation. These perspectives may or may not be conflicting and requires further investigation on how to best use the flexibility of CHP plants.

6.1.3 Sustainable operation of CHP plants and district heating systems

As climate targets and emission limits become more stringent, reduced CO_2 emissions from thermal power plants is key. To increase the long-term sustainability of combined heat and power plants, integration of the plants with carbon capture and storage (CCS) units could be considered. From a plant perspective, carbon capture might in the future be of economic relevance for fossil fuel-based plants to avoid CO_2 emission costs (e.g. waste as a fuel is to an extent of fossil origin), or for biomass-combusting plants to trade so-called negative emissions (bio energy carbon capture and storage, BECCS) that could compensate for fossil CO_2 emissions from other sources that are difficult, or not cost-effective, to avoid.

Implementing carbon capture units in a steam cycle is, however, capital- and energy-intensive and will have an impact on the plant performance, through reduced electricity generation and/or district heating delivery. This impact needs quantification to properly assess the relative benefits and trade-offs for a CHP plant to operate with CCS, and how such operation would propagate in the district heating and electricity systems. For instance, if CHP operation with CCS reduces the heat delivery from the plant to the district heating network, other heat-generating units may have to increase their production for the system to supply the heat demand, which might cause increased CO_2 emissions and operating costs for the system. However, the heat and electricity demand vary over seasons. There may, thus, be times when operation with CCS could be feasible without overly influencing the system operation; and other times when it is desirable to avoid. These issues need to be analyzed and optimized both from a plant (technical feasibility) and system (economic feasibility) perspective.

6.1.4 Designing CHP plants for future operating conditions

The present work is based on reference plants with given designs and focuses on the potential to operate these in a flexible manner. Yet another aspect is how to design new combined heat and power plants with high levels of flexibility, as well as the relative cost-effectiveness of investing in technology options that enhance flexibility. As an example, with the expected future increase in electricity price volatility, it may be of economic interest for CHP plants to further expand the load range, with increased maximum and reduced minimum load. Product flexibility can contribute to load range expansion, as shown in this work; but it might be further improved by the addition of fuel flexibility, or thermal input flexibility. Hybrid CHP-HOB plants, that are designed both with high electricity generating potential and with heat-only generation characteristics in mind, could be of interest.

The possibility to dimension and design equipment for specific energy contexts may enhance the future profitability of the plant. However, the future is difficult to predict; designing CHP plants for uncertain conditions involves risk-taking. On the other hand, designing plants based on the current system also involves a risk, since the present conditions will inevitably change with the transition to a sustainable energy system. Thus, the question is which type of system that plants should be designed for, and what economic impacts the risk-taking involves.

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