Czech Technical University
Faculty of Electrotechnical Engineering

DIPLOMA THESIS

Optimal Production Planning of a Cogeneration System

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Prohlášení

Prohlašuji, že jsem svou diplomovou práci vypracoval samostatně a použil jsem pouze podklady uvedené v přiloženém seznamu.

V Praze dne 23. května 2008 Tomáš Gunorže

podpis

i

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I would like to thank especially my thesis supervisor Petr Havel from the Centre for Applied Cybernetics in Prague, for his effective guidance of my work. I am especially grateful to him for his many invaluable suggestions concerning the draft of this work. I would also like to thank my family for the support they provided me with during my studies.

Abstrakt

Táto práca sa zaoberá problematikou optimálneho plánovania kombinovanej výroby tepla a elektriny. Problém je formulovaný ako problém lineárneho programovania s celočíselnými premennými a vyriešený pomocou univerzálneho matematického solveru. Formulácia problému obsahuje niekoľko typov dynamických obmedzení. Boli uvažované dve plánovacie úlohy: minimalizácia nákladov na výrobu a maximalizácia zisku. Vo formulácii modelu sú zahrnuté aj primárna, sekundárna a terciálna regulácia a niekoľko typov kontraktov na predaj elektriny. Formulácia problému bola otestovaná na konfigurácii kogeneračného systému, ktorá je typická pre strednú Európu a boli dosiahnuté veľmi uspokojivé výsledky.

Abstract

A short term production planning problem for a cogeneration plant is addressed in this work. Both the unit commitment problem and the economic despatch problem are solved. The problem is formulated as mixed integer linear programming problem and solved by a general purpose solver. The model includes ramping constraints and minimum up and down times. Two scheduling tasks are considered: operational cost minimization and profit maximization. Primary, Secondary and Tertiary reserve and various energy contracts are included in the problem. The procedure was tested on a configuration that is typical for cogeneration plants in Central Europe. Test results indicate that the described tool is capable of computing optimal schedules in realistic conditions.

České vysoké učení technické v Praze - Fakulta elektrotechnická

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ZADÁNÍ DIPLOMOVÉ PRÁCE

Student: Tomáš Šimovič

Obor: Technická kybernetika

Název tématu: Optimální plánování provozu kogeneračního systému

Zásady pro vypracování:

1. Seznamte se s principy kombinované výroby tepla a elektřiny.
2. Proveďte rešerši metod používaných pro plánování provozu kogeneračních systémů.
3. Formulujte úlohu optimálního plánování provozu typického teplárenského bloku pro horizont o velikosti 24 hodin.
4. Vyberte a vyzkoušejte vhodnou metodu řešení této úlohy.

Seznam odborné literatury: Dodá vedoucí práce.

Vedoucí diplomové práce: Ing. Petr Havel

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Nomenclature

Table 1: Optimality criteria notation

Variable	Description
$Cost^t(PK_j)$	fuel cost of the boiler PK_j, $j = 1..4$ at time interval t [CZK]
$Cost^t(HK_l)$	fuel cost of the boiler HK_l, $l = 1, 2$ at time interval t [CZK]
$Cost^t(dev)$	cost of deviation from contracted el. production at time t [CZK]
$Cost^t_r(SU)$	start up cost of unit r at time interval t [CZK]
$Cost^t_s(SD)$	shut down cost of unit s units at time interval t [CZK]
$Cost^t_{el}$	cost of producing electrical power at interval t [CZK]
$Cost^t_{as}$	expected prod. cost of el. power and activated AS time interval t [CZK]
$Cost^t(SR)$	prod. cost if positive PR and SR is activated during time t [CZK]
$Cost^t(TR_+)$	prod. cost if positive PR, SR and TR_+ is activated during time t [CZK]
$Cost^t(TR_-)$	prod. cost if negative PR, SR and TR_- is activated during time t [CZK]
P^t_{contrn}	amount of el. to be offered as part of product n at time t [MW]
$P^t_{act}(SR)$	probability of activation of SR at time interval t [CZK]
$P^t_{act}(TR_+)$	probability of activation of TR_+ at time interval t [-]
$P^t_{act}(TR_-)$	probability of activation of TR_- at time interval t [-]
$pr^t_{res}(PR)$	reservation price for PR at time interval t [CZK/MW]
$pr^t_{res}(SR)$	reservation price for SR at time interval t [CZK/MW]
$pr^t_{res}(TR_+)$	reservation price for TR_+ at time interval t [CZK/MW]
$pr^t_{res}(TR_-)$	reservation price for TR_- at time interval t [CZK/MW]
$pr^t_{act}(SR)$	activation price for SR at time interval t [CZK/MWh]
$pr^t_{act}(TR_+)$	activation price for TR_+ at time interval t [CZK/MWh]
$pr^t_{act}(TR_-)$	activation price for TR_- at time interval t [CZK/MWh]
pr^t_{contrn}	price of the electricity product n at time t [CZK]
PR^t	amount of PR to be offered on the market at time t [MW]
$Rev^t_{as\,res}$	revenue from reservation of AS at time interval t [CZK]
$Rev^t_{as\,act}$	expected revenue from activation of AS at time interval t [CZK]
SR^t	amount of SR to be offered on the market at time t [MW]
T	number of time intervals considered
TR^t_+	amount of TR_+ to be offered on the market at time t [MW]
TR^t_-	amount of TR_- to be offered on the market at time t [MW]

Table 2: One hour model nomenclature

Variable	Description
b_j^m	y-intercept of the mth segment of the PWL fuel char. of PK_j [-]
b_l	the y-intercept of the line representing the fuel characteristic of HK_l [-]
$\mathbf{c}_{tgi}$	vector corresponding to the cost coordinate of TG_i work pts [-]
$COST_{PKj}(wp)$	cost of production at PK_j, if no AS are activated [t]
$COST_{PKj}(r)$	cost of production at PK_j, for full capacity of AS r [CZK]
$COST_{HKl}$	cost of steam production at steam boiler HK_l [CZK]
dev	deviation [MW]
HK_l^{min}	minimum production of steam at peak heat boiler HK_l [t/h]
HK_l^{max}	maximum production of steam at peak heat boiler HK_l [t/h]
k_j^m	slope of the mth segment of the PWL fuel char. of PK_j [-]
k_l	the slope of the line representing the fuel characteristic of HK_l [-]
$MAX(tgi)_{PR}$	maximum amount of PR that can be provided at TG_i [MW]
$\mathbf{p}_{tgi}$	vec. corresponding to the power coordinate of TG_i work pts [-]
$P_{tgi}(wp)$	power production at TG_i if no AS are activated [MW]
P_{req}	required production of electricity (sold in long term contracts) [MW]
$P_{contr\,n}$	electricity sold as part of contract n [MW]
PR_{tgi}	PR reserved at TG_i [MW]
PR	total PR provided [MW]
PR_{req}	PR that has to be provided [MW]
PR_{max}	maximum marketable PR [MW]
$\mathbf{q}_{tgi}$	vector corresponding to the heat coordinate of TG_i work pts [-]
$Q_{tgi}(wp)$	heat production at TG_i if no AS are activated [MW]
$Q_{PKj}(wp)$	steam production at PK_j if no AS are activated [t/h]
$Q_{PKj}(r)$	steam production at PK_j for full capacity of AS r [t/h]
Q_{PKj}^{min}	minimum production of steam at steam boiler PK_j [t/h]
Q_{PKj}^{max}	maximum production of steam at steam boiler PK_j [t/h]
Q_{HKl}	steam production at steam boiler HK_l [t/h]
Q_{in}^{st}	input heat flow to the heat storage [MW]
Q_{out}^{st}	output heat flow from heat storage [MW]
Q_{prod}	heat produced [MW]

$Qc_{tgi}(r)$	steam at input of TG_i for full capacity of AS r [MW]
$Qc_{tgi}(wp)$	steam at input of TG_i if no AS are activated [MW]
SR_{tgi}	SR reserved at TG_i [MW]
SR	total SR provided [MW]
SR_{req}	SR that has to be provided [MW]
SR_{max}	maximum marketable SR [MW]
SR_{time}	time during which SR has to reach full capacity [min]
TR_{+tgi}	TR_+reserved at TG_i [MW]
TR_{-tgi}	TR_- reserved at TG_i [MW]
$TR+$	total TR_+provided [MW]
$TR-$	total TR_- provided [MW]
TR_{+req}	TR_+that has to be provided [MW]
TR_{-req}	TR_- that has to be provided [MW]
TR_{+max}	maximum marketable TR_+ [MW]
TR_{-max}	maximum marketable TR_- [MW]
$TR+_{time}$	time during which TR_+ has to reach full capacity [min]
$TR-_{time}$	time during which TR_- has to reach full capacity [min]
u_{tgi}	unit commitment of TG_i (binary), 0 for *off* state, 1 for *on* state [-]
u_{PKj}	unit commitment of PK_i (binary), 0 for *off* state, 1 for *on* state [-]
u_{HKl}	unit commitment of HK_l (binary), 0 for *off* state, 1 for *on* state [-]
$\mathbf{x}_{tgi}(wp)$	cnvx comb. of TG_i work pts if no AS is activated [-]
$\mathbf{x}_{tgi}(r)$	cnvx comb. of TG_i work pts for full positive activation of AS r [-]
$\mathbf{x}_{tgi}(SR+)$	cnvx comb. of TG_i work pts for full positive act. of PR and SR [-]
$\mathbf{x}_{tgi}(SR-)$	cnvx comb. of TG_i work pts full negative act. of PR and SR-
$\mathbf{x}_{tgi}(TR+)$	cnvx comb. of TG_i work pts for full act. of positive PR, SR and TR+ [-]
$\mathbf{x}_{tgi}(TR+)$	cnvx comb. of TG_i work pts for full act. of negative PR, SR and TR- [-]
$\Delta_{PKj}(up)$	maximum increase in production of steam at PK_j [t/min]
$\Delta_{PKj}(down)$	maximum decrease in production of steam at PK_j [t/min]
$\Delta_{tg_i}(up)$	maximum increase of electricity production at TG_i in [MW/min]
$\Delta_{tg_i}(down)$	maximum decrease of electricity production at TG_i in [MW/min]

All variables considered in table 2 represent a variable during one time interval t.

Table 3: Multiple hour model nomenclature

Variable	**Description**
MUT_o	minimum up time of unit o [hour]
MDT_o	minimum down time of unit o [hour]
Pr_o^t	production at unit o at time t [MW]
Q_{cnt}^t	content of heat storage at time t [MW]
Q_{loss}^t	loss of heat at time t [MW]
Q_{in}^{st}	input heat flow to the heat storage [MW]
Q_{out}^{st}	output heat flow from heat storage [MW]
$start_o^t$	occurrence of a start of unit o at time t [-]
$stop_o^t$	occurrence of a stop of unit o at time t [-]
$time_o(up)$	maximum time allowed to increase production at unit o [min]
$time_o(down)$	maximum time allowed to decrease production at unit o [min]
u_o^i	binary vector representing the on/off states of unit o [-]
$\Delta_o(up)$	maximum increase in production at unit o [MW/min]
$\Delta_o(down)$	maximum decrease in production at unit o [MW/min]

Chapter 1

Introduction

Cogeneration is the simultaneous production of useful heat and electric power. Plants based on this principle are quite common in Scandinavia and Central Europe and this form of production is advantageous especially due to their high energy efficiency. However, because the production of heat and power is linked, these systems are more difficult to schedule than conventional power systems. By scheduling we mean both determining the optimal on/off states (*unit commitment*) of the system units and their output (their *economic despatch*) for each time interval of the planning horizon.

Previously, the main focus in scheduling power systems was to minimize operational costs over a given time period while meeting a symmetric power and heat demand. The deregulation of the power market has created an asymmetrical scheduling problem, where a variable heat demand has to be satisfied and power is produced to respond to volatile electricity prices on the market (Rong, A. and Lahdelma, R., 2007). This development has made scheduling of power systems much more difficult and has increased demands on the methods that deal with this task. As efficient operation of energy systems is essential for the competitiveness of energy utilities, the development of effective decision support techniques for production planning is of crucial importance.

The main objective of this work is to address this problem and propose a tool for short term scheduling that could be used at a typical cogeneration plant in Central Europe in liberalized market conditions. The principal contribution of this work is the inclusion of Ancillary Services (AS) into production planning, a problem that has not yet been treated in the reviewed literature. The scheduling problem is formulated as a *mixed integer linear programming* (MILP) problem and solved by a general purpose solver for a system containing eight units and a heat storage. Two optimality criteria are considered, operational cost minimization and profit maximization.

The thesis is outlined as follows. In Chapter 2 we first give a introduction into the concept of cogeneration and present cogeneration technology. Afterwards, two modeling approaches for cogeneration systems are outlined. The final section addresses some aspects of the liberalized energy markets and presents some energy products that a cogeneration plant can provide in the electric power marketplace.

Chapter 3 gives an exhaustive overview of methods found in literature that have been or could be used for production planning of a cogeneration plant. These methods are divided into three categories according to the solution they produce. The first section presents exact methods that produce an optimal solution, Dynamic Programming and Branch&Bounds. The second section outlines relaxation methods, Lagrangian Relaxation and Linear programming. The final section gives an overview of some of the heuristic methods that have been used in cogeneration production planning. Each method is accompanied by an example of application that has been found in literature.

In the first part of chapter 4, definition of a case study is presented. The studied system represents a typical configuration of a cogeneration plant with two extraction turbines, four steam boilers, two peak heat boilers and a hot water storage. The second part of the chapter presents a detailed MILP mathematical model of the system with all relevant constraints and two optimization criteria.

Finally in chapter 5 some results are given to indicate how production planning can work in practice using the developed tool.

Chapter 2

Cogeneration and Energy Production

This chapter is divided into four sections. Firstly, after a general introduction of cogeneration production, two basic types of cogeneration turbines are briefly presented. In the second section, modelisation techniques for cogeneration units, boilers and heat storage are discussed. Subsequently some aspect of the energy market relevant to the short-term scheduling problem solved in this work are presented.

2.1 Definition of Cogeneration

The conventional way to satisfy heating and electricity needs is to purchase electric power from the local grid and generate heat by burning fuel in a boiler. However, a considerable decrease in total fuel consumption and total emissions can be achieved if cogeneration is applied. Probably the most widely used definition of cogeneration is the following (Ramsay, B. et al., 2003):

Cogeneration is the combined production of electrical (or mechanical) and useful thermal energy from a single primary energy source.

The mechanical energy produced can be used to drive a turbine or auxiliary equipment such as compressors or pumps while the thermal energy can be used either for heating or cooling. In case of heating, the thermal energy heats water in a district heating system

or for industrial applications. Cooling may also be effected by absorption units operated through hot water or steam. Production of electricity, heat and cooling is commonly reffered to as *trigeneration*. In the rest of this text cogeneration and combined heat and power (CHP) are used interchangeably.

Operation of a conventional power plant results in large quantities of heat being rejected into the atmosphere either through cooling circuits such as steam condensers or cooling towers or in the form of exhaust gasses. Part of this heat can be recovered as useful thermal energy, increasing the efficiency from 30% - 50% for a conventional power plant to 80 - 90% for a cogeneration system. This increase in efficiency is illustrated by fig. 2.1.

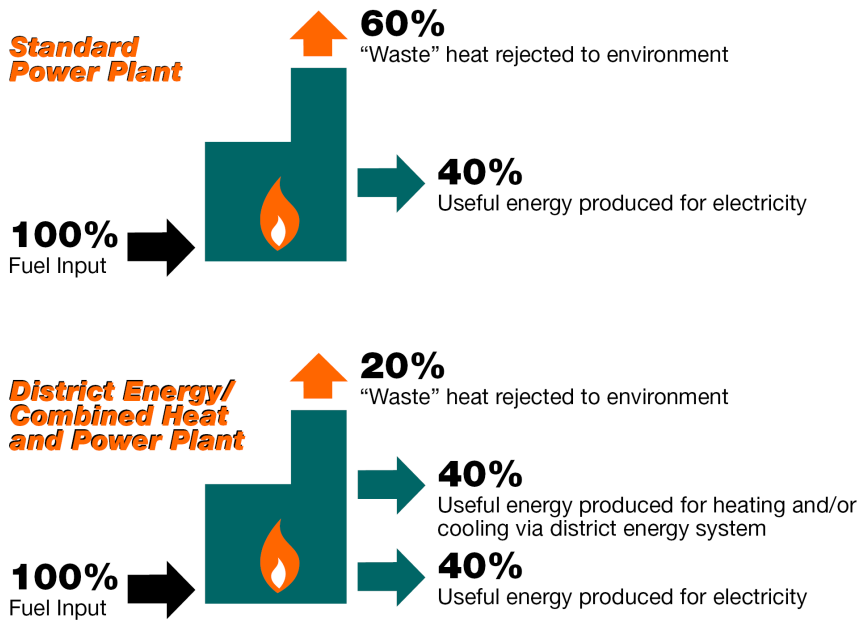

Figure 2.1: Difference in efficiency between a conventional electricity producing unit and a CHP unit. Borrowed from the webpage of the International District Energy Association, *http://www.districtenergy.org/pdfs/ee_comparisons.pdf*

Another major advantage of cogeneration is the fact that it is a relatively enviromentally friendly way to produce energy when emissions are considered. Because of the high efficiency of cogeneration, the amount of emissions per MW of energy produced can be signifficantly lower than with separate production of energy. This fact is becoming increasingly important in the view of the global efforts to reduce CO_2 emissions.

Lower emissions can also be a critical economical advantage if the cost of buying emission permits is considered. Due to these factors, cogeneration is becoming an increasingly attractive form of energy production.

2.2 Cogeneration Technology

Cogeneration cycles can be divided according to the sequence in which power and heat are produced to *topping systems* and *bottoming systems*. In topping systems a high temprature fluid (steam or exhaust gasses) is used to produce electricity and low temprature fluid is used for heating. In bottoming systems, high temprature heat is used first for a process (e.g. in a furnace of a steel mill or of glass-works, in a cement kiln). Subsequently, the process hot gasses are used to drive a gas turbine generator if their pressure is adequate. In the opposite case, these gasses are used to produce steam in a steam boiler which is used to drive a steam turbine. In this work steam topping systems are the main interest.

A system based on a steam turbine has three major components: a heat source, a heat turbine and a heat sink. The operation of such a system follows the Rankine cycle. There are several possible congigurations of a steam turbine. In the following lines, the backpressure turbine and the extraction turbine will be described very briefly. However there are also other types of technology that use the cogeneration principle. For a detailed and exhaustive overview of cogeneration technology the reader is referred to (Orlando, J. A., 1996) or (Petchers, N., 2000)

2.2.1 Backpressure Turbine

In a backpressure configuration a steam exits the turbine at a pressure higher than the atmosperic pressure, depending on the thermal load. It is also possible to extract steam at intermediate stages of the steam turbine, at a pressure and temprature appropriate for the thermal load (see fig. 2.2). The steam releases its heat in the thermal load and the condensate is fed back to the boiler. The main advantage of a backpressure turbine is its high efficiency. However, there is also a downside. The steam mass flow through the turbine depends on the thermal load. This results in little or no flexibility in matching the electrical output with the electrical load. For this reason backpressure turbines are

used mainly in industrial applications where the thermal load does not vary too much with time.

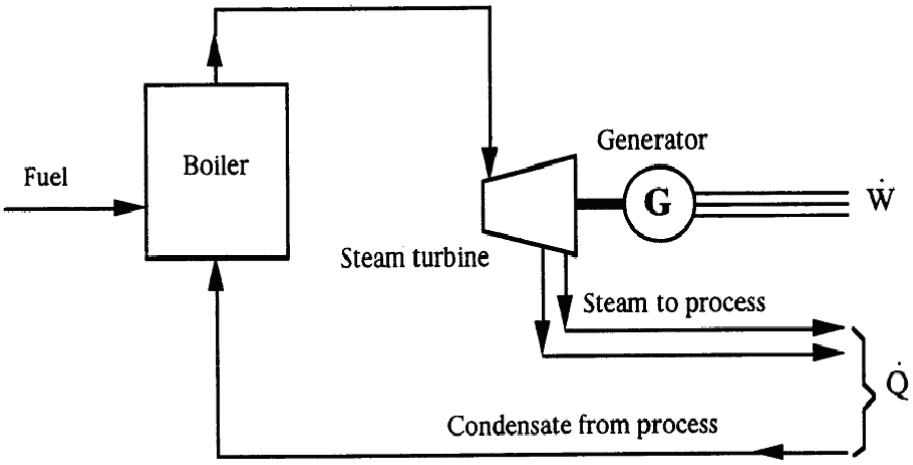

Figure 2.2: Schematic representation of a backpressure turbine, (Ramsay, B. et al., 2003)

2.2.2 Extraction Turbine

In this configuration, steam for the thermal load is obtained by extraction from one or more intermediate stages at the appropriate pressure and temprature. The remaining steam is exhausted in a condenser where waste heat is rejected in the environment. This configuration allows for much greater flexibility. If there is little or no heat load, the system works as a classical condensing turbine. In later sections this will be called the *condensing mode*. A higher heat load can be satisfied by manipulating the steam mass flows of the outputs of the intermediate stages. In this way, both heat and electricity load can be satisfied. This mode of operation will subsequently be called the *backpressure mode*. At peak thermal loads, the turbine can be short circuited by routing some high pressure steam directly from the boiler to the heat exchangers through a *reduction*. We will call this mode of operation the *reduction mode*. Thanks to this flexibility extraction turbines are well suited for application with variable heat demands such as supplying a district heating system. Thermal power plants in the Central Europe are ussually based on this type of turbine.

2.3 Modeling of Cogeneration Systems

In order to be able to apply an appropriate scheduling method, some sort of model that would describe the operation of the system is needed. Two approaches are usually used in practical applications to model steam turbines: description by Balance equations which constitute essentially a white box model and description by P-Q diagrams that can be viewed as a black box model. The last part of this section will present some basic ways to model boilers and heat storage.

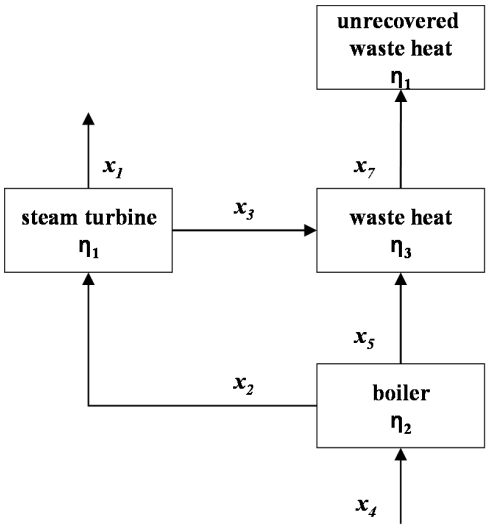

Figure 2.3: Schematic representation of steam turbine balances (Ozalp, N. and Hyman, B., 2006)

2.3.1 Balance Equations

Balance equations describe a system with regard to the first law of thermodynamics. The key assumption in this description is that the system is in a steady state. A very simple model of a steam turbine with heat recovery can be described by the following equations

(Ozalp, N. and Hyman, B., 2006):

$$
\begin{aligned}
x_1 &= \eta_1 x_2 \\
x_2 &= x_1 + x_3 \\
x_2 &= \eta_2 x_4 \\
x_4 &= x_2 + x_5 \\
x_6 &= \eta_3 (x_3 + x_5) \\
x_3 + x_5 &= x_6 + x_7
\end{aligned}
$$

The nomenclature for the equations above is given in table 2.1 and the system is described schematicaly in fig. 2.3.

Table 2.1: Nomenclature for the steam turbine balance equation model

Variable	**Description**
x_1	turbine electricity output
x_2	turbine energy input
x_3	turbine waste heat output
x_4	boiler energy input
x_5	boiler waste output
x_6	recovered waste heat output
x_7	recovered waste heat output
η_1	turbine electric conversion efficiency
η_2	boiler efficiency
η_3	waste heat recovery efficiency

Naturally, a real world balance equation model is much more complicated than the system shown in fig. 2.3 and contains a large number of parameters that need to be measured. Generally such a model is composed of several subsystems such as (Ziebik, A. et al., 1999):

- collectors of feed water
- steam boilers
- turbines and outputs of their stages
- collectors of technological and heating steam

- district heating exchangers

The reader is referred to (Ziebik, A. et al., 1999) for a full balance model of an extraction turbine.

2.3.2 P-Q Diagrams

The balance equation approach to modeling cogeneration systems yields essentially a white box model. The process of designing such a model might in some cases be too complex. If enough data is available, the working area of a turbine can be represented by a P-Q diagram (Lahdelma, R. and Hakonen, H., 2003). This diagram is a polytope defined by coordinates (p, q, c) where (p, q) represents a working point of the turbine yielding p MW of electricity and q MW of heat and c is the cost function representing the amount of steam necessary for operation at the working point (p, q). These points can be determined by measurement or by an analytical model. The exact shape of the P-Q diagram depends on the parameters of the turbine, especially on the temperature of the input steam and the hot water output; one turbine can be characterized by several different PQ diagrams for different tempratures. However, the general form for an extraction turbine has often the shape shown in fig. 2.4. Three different regions, represented by triangles, are visualized on this diagram: the *reduction* mode is represented by region number one, *backpressure* operation corresponds to region number two and *condensation* mode is represented by region number 3.

This polygon is convex and therefore, with a sufficiently large set of characteristic points *(p,q,c)*, any convex cost function can be approximated. Nevertheless, sometimes the operating area of a turbine can have a non-convex shape. In this case, this non-convex polytope can be often divided into smaller convex areas. The convex cost functions of these areas can then be approximated in the same way. (Makkonen, S. and Lahdelma, R., 2006).

2.3.3 Other Facilities of a Cogeneration System

Cogeneration plants are consists not only of cogeration turbines but also of boilers for generating steam that drives the steam turbines and sometimes of heat storage tanks which allow temporary storage of hot water.

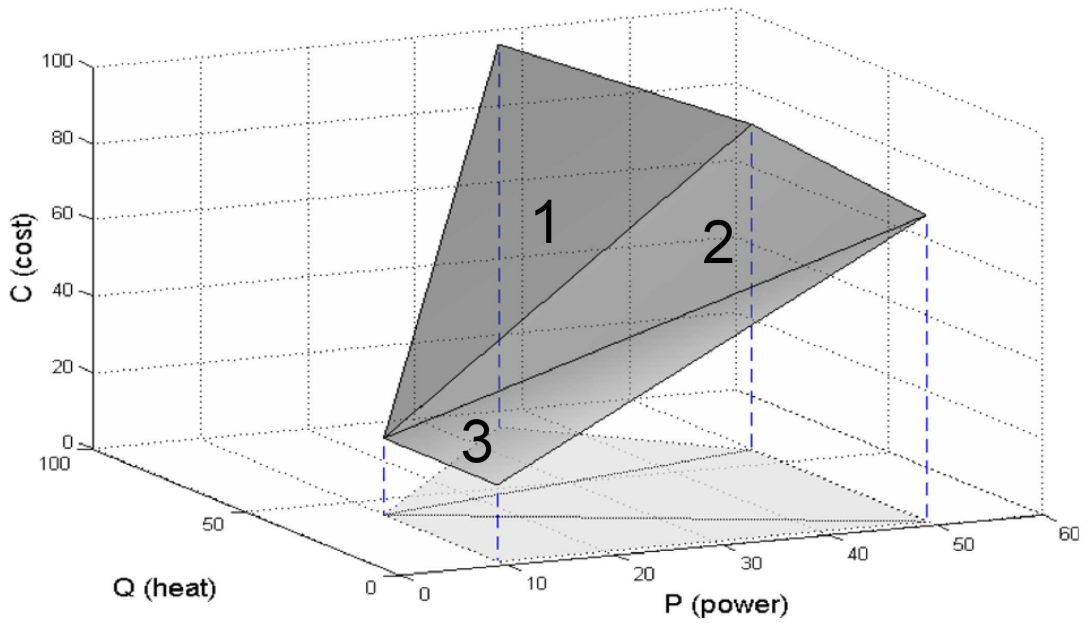

Figure 2.4: A P-Q diagram of an extraction turbine (Rong, A. and Lahdelma, R., 2007)

Boilers

Boilers use a primary energy source such as coal or natural gas to convert water into steam that drives a turbine. In general, the input/output relationship between the quantity of fuel consumed and the quantity of steam produced is nonlinear. This characteristic is computed based on measured data and can be often approximated by a linear (Bojic, M. and Dragicevic, S., 2002), piecewise linear (Seeger, T. and Verstege, J., 1991) or quadratic function (Urbanic, A. et al., 2002).

The most common approximation is a linear one:

$$Q_{FUEL} = aQ + b$$

where Q is the heat transfer rate measured in watts and Q_{FUEL} the fuel consumption.

The same characteristics can be also approximated by a piece-wise linear function:

$$Q_{FUEL} = \sum_{i=1}^{N} k_i Q + c_0$$

where N denotes the number of pieces of approximation.

If even the piece-wise linear approximation does not give sufficient accuracy a quadratic approximation can be used:

$$Q_{FUEL} = \frac{Q}{aQ^2 + bQ + c}$$

A more sophisticated approximation of boiler characteristics does not always guarantee a more accurate optimisation results. In the case study for the Ljublana CHP plant (Urbanic, A. et al., 2002) a linear and a piece-wise linear approximation gave very similar results.

Heat Accumulator

Heat storage is an important element of a cogeneration plant as it allows for a greater flexibility in scheduling of heat output. A heat accumulator can be filled in day time by surplus heat resulting from high energy production expoloting the high day time prices. At night, when electricity prices are low, some of the units in the plant can be shut down and heat demand can be satisfied by releasing heat from the heat storage. Alternatively, inefficient peak boilers can be substituted by a heat storage charged during low heat demand by the output of more efficient units. Usage of a heat accumulator can significantly improve the economics of a cogeneration plant (Bogdan, Z. and Kopjar, D., 2006).

In (Urbanic, A. et al., 2002) heat storage is modeled as first order dynamic system where water temperatures are disregarded.:

$$\frac{dQ}{dt} = Q_{in} - Q_{out} - Q_{losses}$$

A similar approach is presented in (Dotzauer, E. et al., 1994).

(Zhao, H. et al., 1998) present a model that takes also into account the temperature of the returning water from the district heating system. The energy content of the storage tank E_t at time t equals the sum of the energy content at time $t-1$ E_{t-1} and the charging or discharging heat flow $(-Q_t)$:

$$Et = E_{t-1} - Q_t$$

with water temperature in the storage tank not permitted to exceed the maximum temperature:

$$T_t <= T_{max}$$

When the tank discharges $(Q_t > 0)$ then

$$\begin{aligned} T_t &= T_{t-1} \\ Q_t &= M_t cp_w (T_t - Tr_t) \\ Ts_t &= (T_t M_t + Tp_t Mp_t)/(Mp_t + M_t) \end{aligned}$$

where T_t is the temperature in the tank at time t, M_t is the mass flow from the storage tank at time t, cp_w is the specific heat of water, Tr_t is the temperature of the returning water at time t, Ts_t is the supply temperature, Mp_t is the mass flow of the CHP units and Tp_t the water temperature at time t.

When the tank charges ($M_t < 0$), then

$$\begin{aligned} T_t &= \frac{T_{t-1}Vt_t - 3600\Delta\tau M_t Tp_t/\rho}{Vt_{t-1} - 3600\Delta\tau M_t/\rho} \\ Q_t &= M_t cp_w(Tp_t - Tr_t) \\ Ts_t &= Tp_t \end{aligned}$$

where V_{t-1} is the hot water volume in m^3 in the tank $\Delta\tau$ is the time interval in hours and ρ the water density.

2.4 Cogeneration and the Energy Market

This section briefly describes how the energy market influences the scheduling of a cogeneration system. The first part focuses on how a cogeneration plant is affected by recent energy market liberalization. The second part outlines the energy products that a cogeneration system can offer on the energy market.

2.4.1 Cogeneration in a Liberalized Market Environment

One of the major developments in energy production in recent years is market liberalization. Formerly in most countries, nearly all energy producing assets were operated by a national electricity operator with a monopoly on energy production. A demand forecast advised the system operator how much energy had to be produced. Scheduling of units was centralized and there was an obligation to meet the demand with production.

In a liberalized market environment there are multiple generating companies (GENCOs) as opposed to one vertically integrated system operator. GENCOs make bids and offers for contracts for electricity supply which are matched to demand either through an auction or directly in over the counter transactions. This way GENCOs compete on price and they have no obligation to serve the demand in the case of electricity.

Things are different for heat production though. A GENCO still has an obligation to meet the demand of the district heating system it serves or that of its industrial customers. Therefore, a GENCO operating a cogeneration system is faced with the difficult problem of scheduling a system with two tightly coupled outputs, one that needs to meet a time varying demand (heat) while the other being more or less openly traded in energy markets (electricity).

It can be seen that in a regulated marked environment the problem of scheduling was a cost minimization problem: demand had to be met with minimal production cost. Today, optimal scheduling aims to maximize profits which is not the same as cost minimization. If two schedules are feasible, then the one that allows for higher profit is selected even though it may entail higher production cost. Therefore scheduling a cogeneration system involves selecting such a production configuration that produces the required amount of heat while providing maximum scope to increase profitability through effective participation in power markets.

2.4.2 Electricity Contracts

There several types of electricity contracts that a GENCO can sell in the energy market. They can be divided into two groups: Ancillary services (AS) sold to the transmission system operator (TSO) and electrical energy sold to end customers or traders in the form of individual hours or block contracts. This distinction is made because AS and electricity play different roles in scheduling and also because AS are usually sold only to the local TSO while electricity contracts can have a variety of customers.

Energy Products

Traditionally, electricity has been traded bilaterally in block contracts on the over the counter (OTC) market. However, nowadays more and more trading is taking place on organised markets called electricity exchanges such as APX (Netherlands, APX UK (United Kingdom), Borzen (Slovenia), EEX (Germany), EXAA, (Austria), GME (Italy), Nord Pool (Scandinavia), OMEL (Spain), and Powernext (France). In the Czech Republic it is possible trade electricity at Prague energy exchange (http://www.pxe.cz/). Electricity trading taking place on power exchanges concerns both block and hour contracts can be in the form of spot or future deals. Hour contracts represent delivery with a constant output over a specified delivery hour and block contracts the delivery of power with a

constant delivery output over several delivery hours. Exact rules depend from exchange to exchange. For short term scheduling spot trading is more relevant.

Trading on the OTC market usually involves an agreement to supply electricity defined by a diagram over a certain time period. The most common block contracts being traded on the OTC market and (as well as on power exchanges) are *Baseload* (constant supply of electricity over a 24 hour period) and *Peak*(constant supply between 08am and 8pm). For an overview of exchange trading in Europe the reader is referred to (Madlener, R. and Kaufmann, M., 2002).

Ancillary Services

Ancillary services (AS) are essentially the provision of different types power reserves in the form of unused capacity that is kept available for the use by the TSO. The TSO activates this capacity when needed, to ensure secure operation of the transmission system and an equilibrium between demand and production. If this equilibrium is disturbed due to time varying demand and outages in generation and transmission, a power deviation occurs resulting in a deviation of the system frequency from the set point. The responsibility of the TSO is to control and minimize this deviation in real time and take actions to restore the equilibrium and uses AS to achieve this. The Union for the Co-ordination of Transmission of Electricity (UCTE) defines three types of AS that provide means to ensure balance control. (*UCTE Load frequency control and performance,Appendix 1*, 2004):

- **Primary control** - allows a balance to be established at a system frequency other than the set point value in response to a sudden imbalance between power generation and consumption. It must react immediately after an imbalance occurs.

- **Secondary control** - its role is to restore system frequency to its set point value of 50 kHz and release the full reserve of primary control deployed. It has to be deployed typically within 15 minutes of an imbalance occurring.

- **Tertiary control** - any automatic or manual change of the working conditions of a generator that guarantees the provision of an adequate secondary control reserve at all time or allows to distribute secondary control power to the various generators in the best possible way in terms of economic considerations. In Czech Republic, it has to be deployed within 30 minutes of an imbalance occurring.

These AS are provided by GENCOs to the TSO. GENCOs submit bids to the TSO in which they specify at what price they are willing to provide reserve capacity (*capacity price*) for a particular AS and what price they want for activation of this AS (*activation price*). For detailed documentation on AS the reader is referred to the web pages of UCTE (http://www.ucte.org/) and the Czech and Slovak TSOs, CEPS(http://www.ceps.cz/) and SEPS (http://www.sepsas.sk/seps/).

2.5 Conclusion

This chapter gave a general introduction into combined heat and power production. The advantages of cogeneration were discussed and two basic configurations of steam turbines for cogeneration were presented. We have shown two approaches to modeling of cogeneration turbines as well as ways to model heat boilers and a heat accumulator. In the final section, the influence of liberalized energy markets on scheduling a power plant was addressed and different types of energy contracts that a CHP plant could sell were presented.

Chapter 3

Overview of Relevant Scheduling Methods

Considerable planning is necessary in energy production systems to ensure the best use of available resources. This planning involves finding the optimal combination of production units to turn on to meet the requirements of a given load demand. This problem is called the *unit commitment problem (UCP)*. A sub problem of UCP is to determine the exact production output of the different units that are turned on. This problem is known as the *economic despatch problem* (EDP). A large amount of research has been published on solving the UCP problem for conventional power systems (Sheble, G. B. and Fahd, G. N., 1994). This chapter presents an overview of the UCP methods that can used for scheduling of a cogeneration system both for short term and medium and long term planning and is inspired in by the reviews given in (Padhy, P., 2003), (Sen, S. and Kothari, D. P., 1998) and (Halldorsson, P. I., 2003). The methods discussed differ in the size of the system they can solve, solution quality and computational efficiency and are divided into three groups:

- Exact methods
- Relaxation methods
- Heuristic methods

Exact methods are those that are guaranteed to converge to the optimal solution. Relaxation methods are methods that relax certain problem constraints in order to make the problem more easily solvable. A solution of the relaxed problem is however not guaranteed to be feasible with respect to the original problem. Finally, heuristic methods

are those that are not guaranteed to converge to an optimal solution but give a reasonably good solution in a reasonable computation time.

The following three sections discuss each type of methods. The final section gives arguments for the selection of the method used in this work.

3.1 Exact Methods

The main advantage of using exact methods is the fact that they converge to an optimal solution. However, the decision variables that represent the on/off states of production units are binary variables which leads to considerable computation times for larger systems. This is due to the fact that the solution space increases exponentially with the number of production units and time periods of the model. Three different solution methods have been used for the UCP problem to find the optimal solution : *Extensive enumeration*, *Dynamic Programming* and *Branch & Bound*.

3.1.1 Extensive Enumeration

This method represents a simple intuitive approach to solve the UCP problem. Initially, all possible unit combinations are generated and those that are feasible with respect to production constraints are set aside. For each feasible combination, the EDP problem is solved and start up and shut down costs are added. The schedule that gives the lowest cost is then selected.

As all possible unit combinations are tested, this method is guaranteed to find and optimal solution. However, it is fairly obvious that it becomes quickly impracticable as the size of the solved system grows and can therefore be applied only to small problems and a limited number of hours. No article was found that would report on the use of extensive enumeration for CHP production planning but there is no reason why this method would not work for such a system.

3.1.2 Dynamic Programming

In Dynamic Programming (DP) the problem is subdivided into T different *stages* and then solved recursively. Each *stage* represents a time period and for each stage there are

n states that correspond to all the different combinations of production units that are feasible. The problem is solved in an iterative fashion starting either at *stage 1* or *stage T*. Initially, the optimal solution is found for the first stage by determining the best unit combination for the corresponding time period. The optimal solution of the subsequent stage is based on the solution for the previous stage. The process continues until the last stage is reached.

The formulation of the UCP problem for Dynamic programming must have the *Markovian property*: given a current *stage i* the optimal decision made at *stage i+1* depends only on the decision made at *stage i* and is independent of the decisions made at the previous stages.

The number of solutions that must be examined by Dynamic programming is dependent on the number of units and not on the number of units AND time periods and thus is lower than for extensive enumeration. However, the number of *states* grows exponentially with the number of production units and hence DP becomes computationally expensive for larger problem instances. Moreover minimum up and down times are quite difficult to handle with DP.

To handle these difficulties, techniques to reduce the execution time and dimension of the search space have been developed. These include *dynamic programming - sequential combination* (DP-SC), *dynamic programming - truncated combination* (DP-SC), *dynamic programming - variable window* (DP-VW). These methods use priority list techniques and reduced execution time of these method comes at the price of sub-optimal solutions.

An alternative way to reduce execution time is to divide the UCP into smaller subproblems that are easily managed and solved with DP. Coordination of these subproblems is achieved either sequentially or with successive approximations (SA) or in parallel with a hierarchical approach. (Sen, S. and Kothari, D. P., 1998).

When forecast of power demand and heat demand is known with uncertainty, fuzzy logic and fuzzy dynamic programming can be applied. Power and heat demand, or even fuel costs can be expressed as fuzzy membership functions. This variation of DP is effective where uncertainties are considered but this comes at the price of even higher execution time than conventional dynamic programming.

An application of DP to short term cogeneration scheduling with a storage over a 24 hour period is presented in (Dotzauer, E., 1997). In this work, an EDP, for a system consisting of one cogeneration unit, a heat storage, and peak heat units is formulated as a mixed integer nonlinear program (MINP) and its production cost is minimized. No cost is associated with the heat storage. In the proposed algorithm, the energy

content of the heat storage is discretized and the discrete levels of energy content work as states and the time interval as stages. The problem is decomposed into smaller non-convex sub-problems that are dependent on a single time interval and solved repeatedly in an iterative manner by the general purpose nonlinear solver NPSOL. To speed up the convergence, the authors have proposed a heuristic procedure that computes starting point values for the DP algorithm that are fairly close to the optimum. The author reports good performance of the algorithm on short time intervals but the computation becomes prohibitively expensive for longer time periods (76286 seconds as the worst case scenario for a 12 hour period). However the author performed his test on a slow computer by today's standards (Pentium 150 MHz) so this algorithm would probably be feasible on today's machines. The main drawback of this approach was the necessity to solve repeatedly the decomposed nonlinear problems. Another drawback was the fact that unit commitment of units was not considered.

3.1.3 Branch and Bounds

The idea behind *branch and bound* is to successively divide the original problem into smaller subproblems until the individual subproblems are easy to solve. The best of the subproblem solution is the global optimum for the original problem. In the *branching* step of B&B a branching tree is created with each node representing a subproblem. The root of the tree represents the original problem while the leaves are easy problems that have already been solved or subproblems that still have to be processed. The *bounding* step serves to limit the number of solutions that need to be enumerated by excluding parts of the solution space in a systematic manner.

The B&B method proceeds as follows. In the first iteration a feasible solution for the root is found by a heuristic or simply set to ∞. This solution is called the *incumbent solution*. Subsequently, the lower bound is estimated for the root node by solving its LP relaxation. If the LP relaxation solution is feasible with respect to the root node, the optimal solution is found. Else the root node is divided into two or more subproblems by fixing the value of certain integer variables. In the next step, the lower bounds of the subproblems are estimated and the nodes whose lower bound is higher than the incumbent solution can be discarded. For nodes that have not been discarded an attempt is made to find a feasible integer solution for example by a cutting planes algorithm. If a feasible solution is found and it is lower than the incumbent solution it becomes the incumbent solution. If a feasible solution cannot be found the node is further divided into two or

more nodes. The best node from the set of active nodes is chosen and the iteration continues. The algorithm converges when the best incumbent solution can be used to exclude all other nodes in the tree.

In (Seeger, T. and Verstege, J., 1991) the authors present the application of B&B to operational cost minimization of a realistic cogeneration system over a 24 hour period. The authors use PWL functions to approximate nonlinear fuel characteristics and use a fictious blending tank model for boilers with dual fuel usage without providing any details. Steam turbines are modeled by convex P-Q diagrams and their changes due to changing temperatures of input steam are considered. The proposed model also includes heat storage. The problem formulation includes a non equidistant time step with periods of significant load change modeled by 15 minute intervals as opposed to 1 hour for others. This leads to a reduction of time steps, with 50 as the maximum value as opposed to 96. To reduce the computational time further the authors decided to omit certain binary variables and minimum up and down time constraints by analyzing the demand load profiles. The approach was run on a general purpose MILP solver on a tested on a system containing 13 units with satisfying results.

In (Rong, A. and Lahdelma, R., 2007) a very efficient customized B&B algorithm is presented for the medium and long term EDP of CHP plants. The authors consider non-convex P-Q diagrams of cogeneration turbines and formulate the problem as a mixed integer linear problem with profit maximization as objective. The binary variables in the problem represent the convex sub parts of the P-Q diagram. They use decomposition techniques to divide the original multiple-period model into hourly models. These must be solved once or multiple times to obtain the solution of multi-period model, depending on the presence of dynamic constrains such as ramping constraints, start-up and shut-down costs or heat storage constraints. To obtain a rapid solution of the hourly model an envelope based algorithm is used. The basic idea behind the envelope algorithm is the fact that the most efficient operation of the CHP plant is on the lower envelope of the convex polytope that represents a feasible operating area. This lower envelope has the form of a piece-wise linear cost function for a given power price. The authors have developed an efficient algorithm to construct the lower envelopes of operating region that can be run online, during the optimization, or offilne to precompute lower envelopes for a given unit and then use them as a look up table during the optimization procedure. The advantage of the online approach is the fact that it can quickly adapt to major changes in parameters in the hourly model, while the offline approach is faster for small changes. To solve the hourly sub problem the set of envelopes for the considered CHP

units is searched systematically to obtain the envelope with the smallest slope. As the problem for the subsequent hours is very similar previous solutions are reused to solve the model faster. Besides an efficient procedure to solve the subproblems represented by the hourly models the B&B algorithm uses also customized branching and bounding methods. The branching step is based on LP relaxation of the binary sub area variables and exploits the special structure of the problem by forming multiple child nodes, one for each subarea. This leads to a significantly lower number of nodes than what a brute force algorithm might produce by simply branching on each binary variable. The resulting LP relaxation has a special structure that allows the application of the envelope algorithm. The bounding step exploits the envelopes of the relaxed subproblems to compute tight lower bounds and thus discard unpromising solutions. As the parameters for hourly models are often very similar the B&B algorithms uses the solution from the previous hour to prune the unpromising branches of the search tree. The algorithm was tested on a variety of test problems consisting of 3-6 CHP turbines with non-convex P-Q diagrams for a planning horizon of one year (8760 hourly models) without dynamical constraints. The authors report that the proposed algorithm is 661 to 955 (with an average of 785) times faster than the CPLEX MIP solver. No information was given about the actual running time.

3.2 Relaxation Methods

In some problems there is a small subset of constraints that make the problem difficult to solve. If these constraints are dropped (relaxed) the problem can be solved more easily. These constraints can be also added to the objective function which results in a price that is paid if they are not satisfied. Methods that meet this description are classified as relaxation methods in this review. With respect to the original problem, these methods produce optimal solutions at best but in some cases they can produce suboptimal or even infeasible solutions. In general these methods are faster than exact methods end can solve larger UCP problems with a longer time horizon where exact methods fail due to their computational time explosion. Two methods are presented, *Lagrangian relaxation* and *Linear programming*.

3.2.1 Linear Programming

Linear programming is classified in this section because it solves a relaxed version of the UCP problem without binary variables. Relaxation is performed by disregarding the binary variables and setting the minimum capacity of each unit to zero. This results in a EDP problem. As there are no binary variables, start-up cost cannot be used and units are selected based only on production costs.

The LP relaxation is in most instances of the UCP problem a rather crude approximation as it is quite likely that the solution of the relaxed problem is infeasible with respect to the original problem. Nevertheless, this method may be appropriate when the number of units is large or the time horizon under study is long, as large LP problems can be decomposed (using the Dantizg-Wolfe decomposition for example) and solved quite easily. (Halldorsson, P. I., 2003) reports that LP relaxation has been used to schedule a large scale CHP system in the Coppenhagen area and the results have been compared to optimal solution without relaxation. The difference in objective function reported was fairly small, but final solution had to be changed manually to reach a feasible solution.

3.2.2 Lagrangian Relaxation

In the UCP, the time periods are bound together by the start-up costs and for a given time period all units are bound together by the demand. The idea behind Lagrangian Relaxation (LR) is to relax the demand constraint and embed it into the objective function with a penalty multiplier. The resulting objective function can be rearranged to create N subproblems, one for each unit. Each subproblem is independent of the other units and only dependent on time.

The solution process of LR consists of iterated solutions of the master or primal problem and the dual problem. First the master problem is solved for given values of Lagrangian multipliers λ. Subsequently the multipliers are updated by solving a dual problem of the master problem and the master problem is solved again with these updated values. The difference of the objective value between the dual problem and the master problem gives the duality gap. The duality gap provides a measure of optimality of the given solution. The solution method for the master problem is usually dynamic programming or B&B. The dual problem can be solved by subgradient methods or heuristic methods such as genetic algorithms if the problem is large.

The advantage of LR is flexible handling of different types of unit constraints (such

as warm and cold start of units) and rather efficient in computation time, especially with increasing number of units. It is more sensitive to longer time horizons due to the methods used to solve the master problem (DP or B&B). The main disadvantage of LR is the final convergence of the Lagrangian multipliers which can lead to infeasible solution with respect to demand.

In (Thorin, E. and Brand, H.and Weber, Ch., 2005) an approach for optimizing the operation of CHP plants in liberalized energy markets based on LR is presented. The reported work was part of the international OSCOGEN project (www.oscogen.ethz.ch/) that addressed the problem of optimal operation of CHP in market conditions in depth. The studied model covers a system consisting of boilers, extraction, condensing, back pressure and gas turbines, fueled by coal, oil or gas and two district heating system. The objective function considered is profit maximization and includes also the possibility to buy and sell power on the spot market. Heat storage is not included. To model boilers a linear approximation was used, turbines were represented by P-Q diagrams and their steam consumption approximated by a linear function. The reported approximation error ranges is 2% for absolute fuel consumption to up to 10% percent for marginal fuel consumption. Three Langrange multipliers are used in the objective function, one for the power balance and two for the heat balance of the two district heating systems. The master problem is solved by the B&B method using the simplex solver and the lagrange multipliers in dual problem are updated by the subgradient method. The optimisation period is divided into shorter periods with overlaps and these shorter periods are solved separately. The proposed method was tested on a system inspired by the CHP plant in Berlin, consisting of 10 units with the possibility to provide secondary reserve and buy and sell power on the spot market. The LR method was tested on time periods ranging from four days to one month and compared to a MILP approach solved by CPLEX. The LR method was faster for longer time periods and more complicated heat demand diagrams.

In (Dotzauer, E. et al., 1994) a LR method is presented to solve the UCP and EDP for a CHP system with a storage. The objective was to minimize operating costs and the considered cost functions were quadratic. The author also considers time dependent start-up cost, allowing for formulation of costs of a warm start and cold start. No cost is associated with the heat storage. The EDP and UCP are solved separately by LR based algorithms and five different methods to compute Lagrange multipliers are presented. The approach is tested on a system consisting of four units and a heat storage over a 24 hour period divided into one hour intervals. No results that would show computation

time are presented. The tests performed were more focused on the different performances of the methods for updating Lagrangian multipliers.

3.3 Heuristic Methods

In engineering context a heuristic is a computational method based on empirical information or common sense rules that can produce a decent solution of a complex problem in reasonable time. The optimality of the resulting solution cannot be guaranteed and in many cases it is difficult to determine how close the solution is to optimum. Heuristic methods have the following advantages :

- They can give good a solution in short computation time where exact methods either fail to produce a solution or are too slow with respect to time
- They are often more simple to implement that exact methods
- They are less sensitive to model formulation than exact methods and can handle more difficult objective functions and constraints

There is a wide range of heuristics and they can differ significantly. Some are tailored to specific problems while others, called *metaheuristics*, can be applied to a wide range of tasks. Metaheuristics can be described as a general algorithmic framework which can be adapted to a specific optimization problem with relatively few modifications. *Genetic algorithms* (GA), *Simulated annealing* (SA) and *Tabu search* (TS) are examples of such methods that have been applied to the UC problem. In addition to these, a simple heuristic, the *Priority List*, will also be discussed.

3.3.1 Priority List

This method is among the most simple procedures to solve the UCP problem. It proceeds by creating a priority list of production units based on their production costs. The production costs is calculated by the priority function which can include fuel costs, shut down and start up costs, etc. Production units are then committed in the order given by the priority function, starting with the unit with the lowest production costs in a way that satisfies the production constraints. The priority lists technique results in sub-optimal

solutions. However, it can be adequate for smaller systems and is widely used due to its extreme simplicity, ease of application and understanding. The heuristic ordering resulting from this technique can be translated into rules and executed as an expert system (Sen, S. and Kothari, D. P., 1998). No work was reported in literature that would apply this method to cogeneration plants. Its application to CHP plants would be a little more difficult than in the case of conventional power plants due to the fact it is more complicated to design a priority function for two outputs and different demand diagrams.

3.3.2 Simulated Annealing

Simulated Annealing (SA) is based on a local search strategy and is capable of climbing out of a local minimum. SA is similar to a steepest descent algorithm with one crucial difference: instead of accepting only solutions that give lower function value than the previous solution, SA accepts non-improving solutions with a probability p. This probability depends on a control parameter T, usually referred to as temperature, and the difference in the objective value of the two solutions $\delta = f(x_{k+1} - f(x_k))$. The acceptance probability provides the algorithm with a way to escape from local minima. The acceptance probability is modified in a controlled manner which results in an equilibrium being reached in some good areas of the solution space and ultimately convergence.

The probability distribution for accepting worse solutions is usually the Maxwell Bolzman distribution $e^{-\Delta/T}$. The temperature parameter T is initially set to 1 allowing the algorithm to explore the search space. T is set to gradually decrease to allow only downhill steps at the end. For more information on SA, the reader is referred to (Pirlot, M. and Vidal, V., 1996).

In (Halldorsson, P. I., 2003) SA has been applied successfully to solve the UCP problem of a large energy system that included CHP units with cost minimization as an objective. SA was only used to find an appropriate combination of on/off states, the linear and convex EDP problem was solved using a fast heuristic. Two reasons are given for selecting this approach. Firstly, to solve the UCP the SA procedure calls the EDP computation many times which would lead to large computation times if the EDP was solved by LP. Secondly, the author reports that heuristic can be potentially extended to non-convex nonlinear problems. The EDP heuristic exploits the derivative of the cost function of each unit which is called the *gain*. The search proceeds by selecting units one by one according to increasing values of their gains and increasing their production from

its minimum until maximum production is achieved or all demand is fulfilled. In case of extraction units the maximum production considered is the production of heat. In this respect it resembles the priority listing heuristic. The performance of the heuristic was tested on a system containing four extraction units, 10 backpressure units, four condensing units and seven heat only boilers and compared with the commercial solver CPLEX. The deviation from the optimal solution was reported to be less than 4% with a maximum deviation for individual units of 10%. The reported time for the EDP heuristic is very fast - 1.2 msec for 24 time periods for a system of 25 units on average.

In the SA implementation described, each solution is represented as three different $N \times T$ matrices, representing the unit status, heat and electricity production at each unit and each time interval. From these, only the unit status matrix is stored during the iterations. The state space is searched by selecting one unit status at a time at random and flipping its status. Other unit states are flipped also to ensure the feasibility of the solution with respect to the minimum up and down times. An alternative approach that is also used is to change all unit states in either the forward or backward direction (with equal probability) of unit state selected at first. For each new solution the objective function is updated by recalculating the EDP only for the time period where a change occurred. This is possible due to the fact that time periods are indepents.

The performance of the combined algorithm was tested again on the system consisting of 25 units for time 24-96 time intervals and compared to results computed by CPLEX. The deviation from the optimal solution is reported to increase with the increasing number of time interval, reaching 4.1 % for mean error and 6.1% for worst error. The computation time is vastly inferior in case of the SA algorithm - 35 seconds for the 96 time interval case as opposed to 960 seconds for CPLEX. It was also found that for CPLEX, the computation time explodes for longer time periods than 24 intervals (increase from 20 seconds for 24 intervals to 420 for 48 intervals). Another test involved 35 units. In this case CPLEX was faster in the test case for 24 time intervals but again, its computation time exploded later on and was not able to find an optimal solution for 72 and 96 time intervals. In contrast SA had a computation time of 96 seconds for 96 time intervals.

3.3.3 Tabu Search

Similarly to SA, Tabu search is also based on a local search strategy and is capable of climbing out of a local minimum. This is achieved by keeping a dynamic list of recently visited solutions and forbidding all movement back to these solutions for a certain number

of iterations. When a local minimum is reached during the search it is put into the tabu list and the algorithm is forced to move towards a worse solution. The local minimum cannot be revisited for a certain number of iterations. In essence, the method walks back and forth around the solution space between several minima. The algorithm is stopped if the number of iterations have reached a preselected limit or if the solution has not improved during a certain number of iterations. This method is easy to implement, can handle large problem instances and longer time horizons. The main disadvantage of Tabu search is the computation overhead associated with storing the tabu list. For more detailed information on Tabu, the reader is referred to (Hindsberger, M. and Vidal, V., 2000).

Tabu search has been tested on the same problem as the SA work presented in the previous section (Gislason, G., 2003). The same EDP heuristic has been used. Like in the SA, only feasible solutions with respect to the minimum up and down times were considered. The local search works by selecting a unit and a time interval at random and evaluates the different possibilities to turn the unit off or on for all the time intervals considered while respecting the minimum up and down constraints. If more choices are available, one is selected at random. The algorithm performs a limited number of searches of the neighborhood this way and then moves to the best solution. To decrease memory requirements two vectors for each solution were stored in two tabu lists instead of the entire matrix. The first was the number of *ON* time periods for a given unit and the second was the number of ON periods for a given time interval. A solution was declared tabu only when it was tabu in both of the tabu lists. As in the case of SA the EDP heuristic was updated only for the time periods where a change has occurred.

The performance of the algorithm was tested on the same system as the SA method in the previous section. The reported maximal error was 9% for the 25 unit case and 96 time intervals at an execution time of 8 minutes. This is half of the CPLEX time of 16 minutes for the same problem. The reported deviations form the optimal value for the 35 unit case were slightly lower and the execution times were not shown. In comparison to the SA method, the TS had found solution with a roughly the same or slightly higher mean value and its solutions had higher variance. TS needed much fewer iterations than SA to find good solutions but the computational times were similar in the 24 time interval test case. This is due to the fact that comparing TS solutions to the tabu list is computationally expensive. In the other test cases SA was faster than TS and TS was dependent on the initial solution while SA was not. It is surmised that the inferior performance of TS compared to SA is due to the fact that TS has trouble finding

a good solution in a promising area while SA is sufficiently cooled down to find one.

3.3.4 Genetic Algorithms

Genetic algorithms are adaptive search techniques based on the principle of natural selection. The method operates as an iterative search procedure on a set of candidate solutions (often called individuals) of fixed size. Each candidate solution is usually encoded as a binary string that is called a *chromosome*. The quality of each candidate is estimated as a fitness function is identical with or similar to the objective function. A genetic algorithm operates in the following way. First, an initial population is created. Subsequently the population is evaluated and parents are selected. Offspring is created from the selected parents using the crossover operator and the children are mutated. Finally a next generation is selected from the current population using a variety of selection techniques (roulette wheel, stochastic universal sampling, etc). The process continues with selecting new parents and iterates for a preset number of generations. For an overview of GAs the reader is referred to (Marik, V. and Stepankova, O.and Lazansky, J., 2001).

In case of UCP, the chromosome gives the unit on and off times and solution to the EDP is computed by a different method such as LP for the given schedule.In the iterative process ever higher quality individuals are created by using selective breeding and recombination strategies (crossover, mutation). Each set of individuals at a particular point in the iterative process is referred to as a generation. Various genetic algorithm based approaches have been used to solve the UCP problem. Their main advantage is that they can solve large scale problems and that they represent on and off times naturally. They are good at finding good solution areas but not as effective in finding good solutions locally in this area (Sen, S. and Kothari, D. P., 1998). To overcome this GAs have been combined with other heuristics (Cheng, C. and Liu, C., 2002).

The main problem with using genetic algorithms for UCP is to maintain feasibility with respect to minimum up and down constraints. This is due to the fact that feasible schedules are frequently destroyed by the crossover and mutation operations. Even infeasible solutions can contain valuable partial solutions. This problem is usually overcome by assigning penalties to infeasible individuals or by implementing repair mechanisms to fix infeasible solutions. According to (Sen, S. and Kothari, D. P., 1998), the computation time increases in a quadratic way with the number of units in the system. Genetic algorithms are inherently parallel and therefore a parallel implementation can be used for concurrent processing to reduce computation time.

3.4 Conclusion

In this chapter we have presented three types of approaches to solving the Unit commitment problem. The exact methods, Extensive enumeration, Dynamic programming, and Branch and bounds guarantee an optimal solution but can be computationally expensive. The relaxed methods, Linear programming and Lagrangian relaxation, are faster but may compute a solution that is infeasible in respect to the original problem. Finally, heuristic methods, Genetic algorithms, Tabu search and Simulated annealing can handle large problem sizes but give suboptimal results.

Chapter 4

Model formulation and Case Study

4.1 Definition of a Case study

The goal of this thesis is to develop a decision support tool that can be used in liberalized market conditions for production planning of a typical cogeneration plant in the Central European region. The focus is short term scheduling for a 24 hour period. A typical configuration for cogeneration plants in the Czech Republic and Slovakia, shown in fig. 4.1, has been taken from (Broz, K., 1997).

This system consists of four steam boilers PK1-4 (aggregated in fig. 4.1) and two extraction turbines TG1 and TG2. A heat storage and two peak heat boilers (not shown in the figure) have been added to make the problem more complicated. The input/output relationship between the quantity of fuel consumed and the quantity of steam produced for boilers PK1-PK4 are approximated by a piece wise linear convex function while the peak heat boilers are modeled by a linear relationship, see fig. 4.2. The working areas of the considered extraction turbines TG1 and TG2 are shown in fig. 4.3 and fig. 4.4. A convex hull of these working areas was computed, yielding a set of working points that forms a PQ diagram for each turbine. The considered PQ diagrams are the projections of the 3D surfaces in fig. 4.3 and fig. 4.4 onto the PQ plane. A relatively small number of points was sufficient to model the working areas accurately: 8 points for TG1 and 9 points for TG2. The working points are shown in the Appendix 1.

For this system, two types of scheduling problems are of interest:

- operational cost minimization - given a diagram for expected heat demand, electrical energy and AS products already sold, compute the optimal unit commitment and economic despatch of all units of the system that minimizes operation costs.

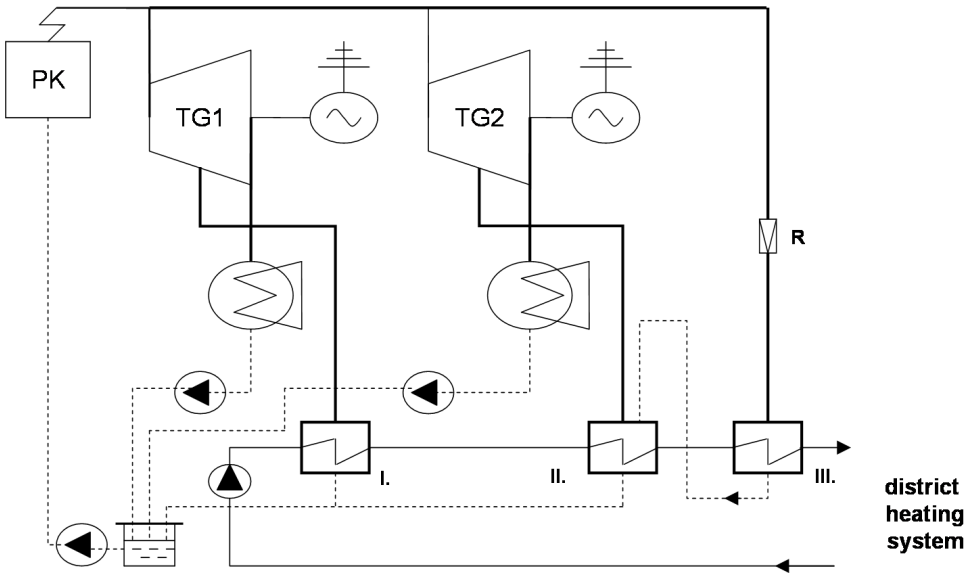

Figure 4.1: Schematic representation of the studied CHP plant (Broz, K., 1997)

- profit maximization over a 24 hour period - given a diagram for expected heat demand, electrical energy and AS products already sold, determine the the optimal combination of recommended energy and AS products to be sold, unit commitment and economic despatch of all units of the system that maximizes expected operating profits.

For energy products, single hour electricity products, multiple hour block products and contracts for Primary, Secondary and Tertiary Reserve are considered. The considered time period is 24 hours in one hour time intervals.

The following types of constraints need to be respected:

- demand constraints - heat demand must be met at all times and already sold AS contracts need to be honored. For energy products, a deviation from announced production is allowed and results in increased cost due to the necessity to pay for the incurred deviation.

- working area constraints - the despatch of all units as well as the amount of reserved AS needs to be in the bounds set by minimum and maximum production of each unit

- ramping constraints - production of units can change only by a limited amount between hours. Also, AS activation cannot result in changes in production exceeding

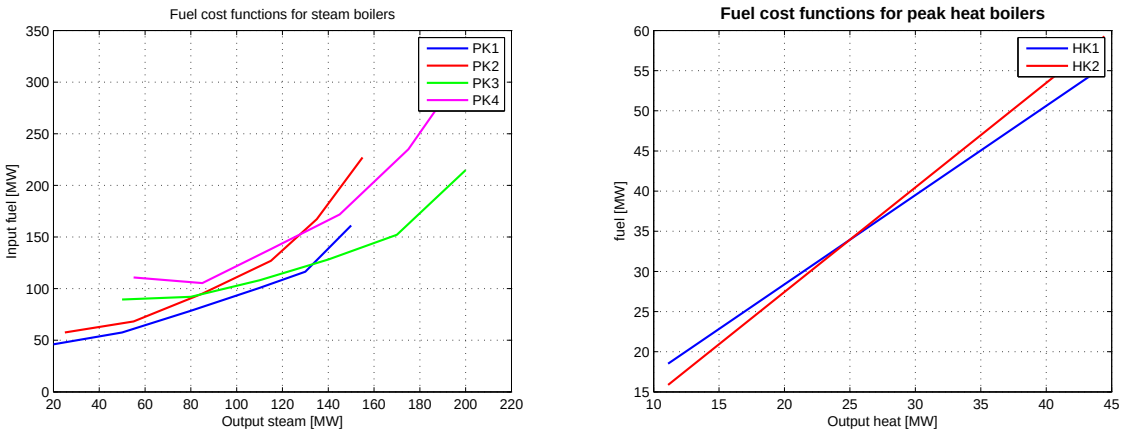

Figure 4.2: Fuel cost function for boilers PK1-4 and HK1-2

this limit.

- minimum up and down constraints - once a unit is switched on or off it needs to be kept in that state for a certain minimum amount of time

4.2 Final Choice of Solution Method

In Chapter 3 we have presented a number of methods that are applicable to production planning problems involving CHP plants. The global optimality of the solution provided by the method is a very important parameter. Therefore, exact methods are preferred. As the studied system is not very large, their application seemed feasible. Hence the main choice was between Dynamic Programming and the Branch & Bounds method. Finally, Branch & Bounds was preferred for the following reasons:

- a mixed integer linear programming problem formulation solved by B&B offers combined solution of the UCP and EDP
- minimum up and down times are more easily defined by linear constraints (Seeger, T. and Verstege, J., 1991)
- efficient general purpose commercial and academic solvers are accessible and can handle mixed integer linear programming problems of relatively large sizes

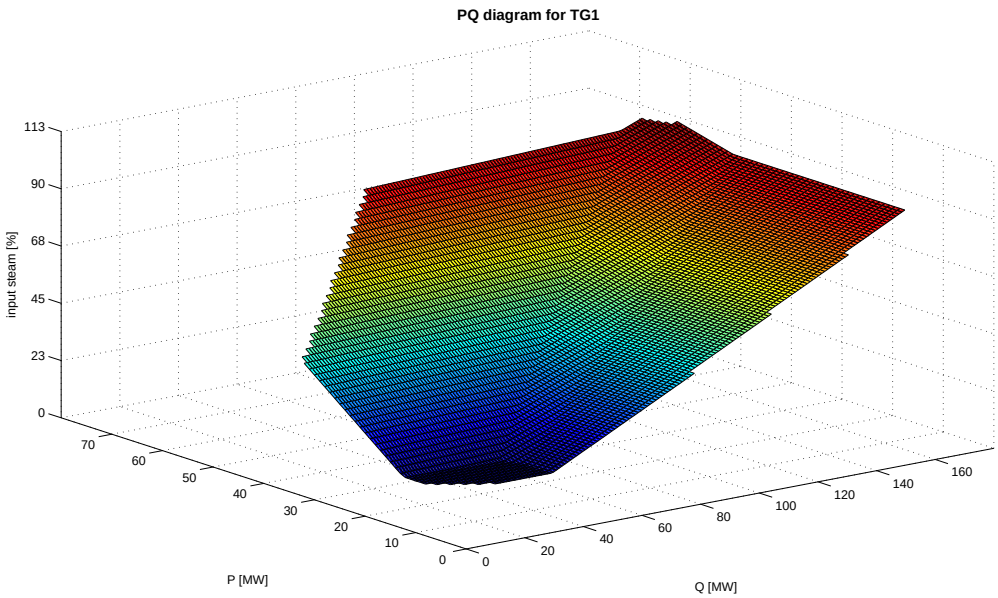

Figure 4.3: Operating area for TG1. P signifies electricity, Q heat, input steam is the steam produced by steam boilers that drives the turbine.

- effective tools to define linear programs and build large scale MILP models are available and widely used and allow flexible addition of new components without reprogramming
- a MILP problem formulation can include nonlinear relations approximated as piecewise linear functions
- no results were reported in literature that would suggest that Dynamic Programming might have a vastly superior performance over B&B on the studied problem

4.3 Model Formulation

The considered scheduling problem can be formulated as a mixed integer linear programming problem with the optimality criterion

$$\min\{\mathbf{Cx}\}$$

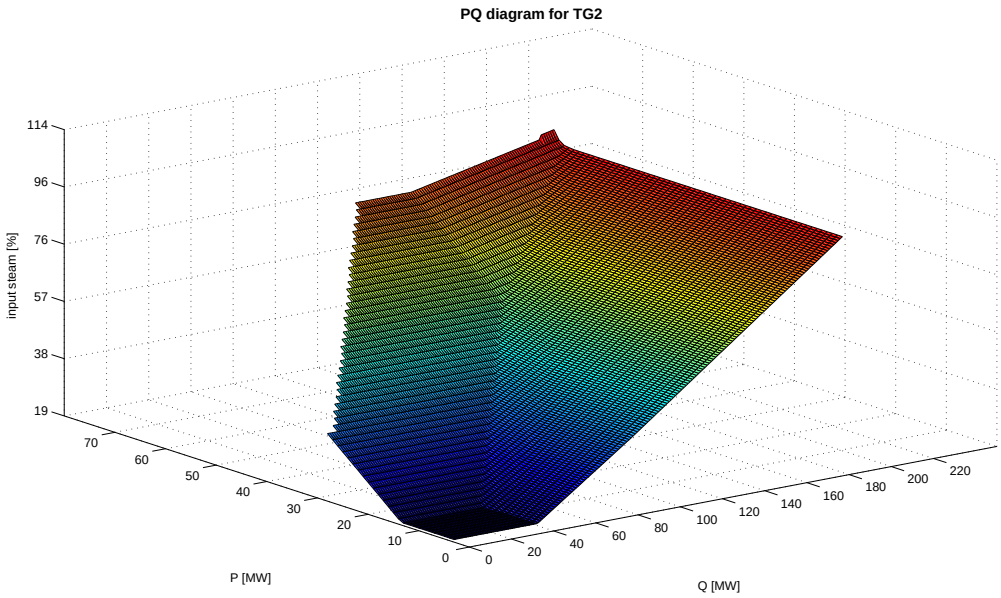

Figure 4.4: Operating area for TG2. P signifies electricity, Q heat, input steam is the steam produced by steam boilers that drives the turbine.

subject to inequality and equality constraints

$$\begin{aligned} \mathbf{Ax} &\leq \mathbf{b} \\ \mathbf{A_{eq}x} &= \mathbf{b_{eq}} \end{aligned}$$

where $\mathbf{x}$ is a vector consisting of continuous or integer optimization variables, $\mathbf{C}$ is a vector defining cost in the optimality criterion, $\mathbf{A}$ and $\mathbf{A_{eq}}$ are matrices defining left hand constraints and $\mathbf{b}$ and $\mathbf{b_{eq}}$ are vectors defining right hand side constraints. In the following lines first the optimality criterion is discussed and subsequently the one hour and multiple hour models are developed.

4.3.1 Optimality Criteria

For notation in this section, the reader is reffered to Table 1 in the Nomenclature section.

As mentioned earlier, two scheduling tasks are of interest: cost minimization subject to fulfilling demand constraints and profit maximization.

Cost minimization criterion

In the cost minimization scheduling task we consider that a certain heat demand has to be satisfied and a certain amount of power has to be generated with a possible deviation between actual and announced production that incurs a deviation cost. There could also be reserved capacity for AS that has to be met. We want to minimize the actual cost of producing power and heat. This cost consists of the fuel costs of the steam boilers PK1-4 and the peak heat boilers HK1, HK2, the cost of the incurred deviation between announced and actual production and the start-up and shut-down costs of all units. The optimality criterion for cost minimization has the following form:

$$\min \left\{ \sum_t \left(\sum_j Cost^t(PK_j) + \sum_l Cost^t(HK_l) + Cost^t(dev) + \right. \right.$$
$$\left. \left. + \sum_r Cost^t_r(SU) + \sum_s Cost^t_s(SD) \right) \right\}$$

Profit maximization criterion

The goal of profit maximization in short term production planning is to meet already sold long term contracts with minimal cost while making supplementary profit by the sale of additional energy products and AS on the short term market. These additional energy products can be either electricity hour or block products with a price for a certain amount of electricity in CZK/MWh or contracts for AS.

For Primary Reserve (PR), Secondary Reserve (SR) and positive and negative Tertiary Reserve (TR_+, TR_-), a reservation price in CZK/MW is paid for reservation of a certain capacity in MW. An activation price in CZK/MWh is paid for the delivery of SR, TR_+ and TR_- regulation energy when these services are activated. There is no payment for activation of PR. As SR, TR_+ and TR_- may or may not be activated the cost of providing them and the revenues they generate when activated are given weights that will be called *probability of activation* in the rest of the text (The word probability used here is meant in the subjective Bayesian meaning of the term). The optimization criterion that maximizes expected profit is defined as:

$$\min \sum_{t=1}^{T} Cost_{el}^{t} + Cost_{as}^{t} + Cost^{t}(dev) + \sum_{r} Cost_{r}^{t}(SU) + \sum_{s} Cost_{s}^{t}(SD) - \\ - \left(Rev_{as\,res}^{t} + Rev_{as\,act}^{t} + Rev_{el}^{t}\right),$$

where the actual cost of producing electrical energy and heat at time interval t when no AS are activated is the sum of the fuel costs of the different boilers,

$$Cost_{el}^{t} = \sum_{j} Cost^{t}(PK_{j}) + \sum_{l} Cost^{t}(HK_{l}),$$

the expected cost of providing regulation energy for the reserved capacity of AS when they are activated at time interval t is the sum of production costs for operating points corresponding to maximum capacity for each AS (see fig. 4.5) weighted by the probabilities of activation,

$$Cost_{as}^{t} = P_{act}^{t}(SR)Cost^{t}(SR) + P_{act}^{t}(TR_{+})Cost^{t}(TR_{+}) + \\ + P_{act}^{t}(TR_{-})Cost_{w\,pt}^{t}(TR_{-}),$$

revenues from reservation at time t are the sum of the revenues for each AS that are given by the reservation price $\times$ reserved capacity for each AS,

$$Rev_{as\,res}^{t} = pr_{res}^{t}(PR)PR^{t} + pr_{res}^{t}(SR)SR^{t} + pr_{res}^{t}(TR_{+})TR_{+}^{t} + \\ + pr_{res}^{t}(TR_{-})TR_{-}^{t},$$

revenues from activation at time t are the sum of expected activation revenues for each AS, given by the probability of activation $\times$ activation price $\times$ reserved capacity for each AS,

$$Rev_{as\,act}^{t} = P_{act}^{t}(SR)pr_{act}^{t}(SR)SR^{t} + P_{act}^{t}(TR_{+})pr_{act}^{t}(TR_{+})TR_{+}^{t} + \\ + P_{act}^{t}(TR_{-})pr_{act}^{t}(TR_{-})TR_{-}^{t},$$

and finally the revenues from electric energy products at time t are the sum of the revenues for each product that are given by the product price $\times$ the amount of electrical energy

provided in this product:

$$Rev_{el}^{t} = \sum_{n=1}^{N} pr_{contr\ n}^{t} P_{contr\ n}^{t}.$$

We note that the criterion is not equal to expected profit as it contains more than one instance of the fuel costs to produce heat and electrical energy when no AS are activated (These costs are contained in the terms $Cost^t(SR)$, $Cost^t(TR_+)$ and $Cost^t(TR_-)$, see fig. 4.5). This is necessary for the criterion to be well posed. However, this fact does not represent a problem because the criterion moves linearly with expected profit.

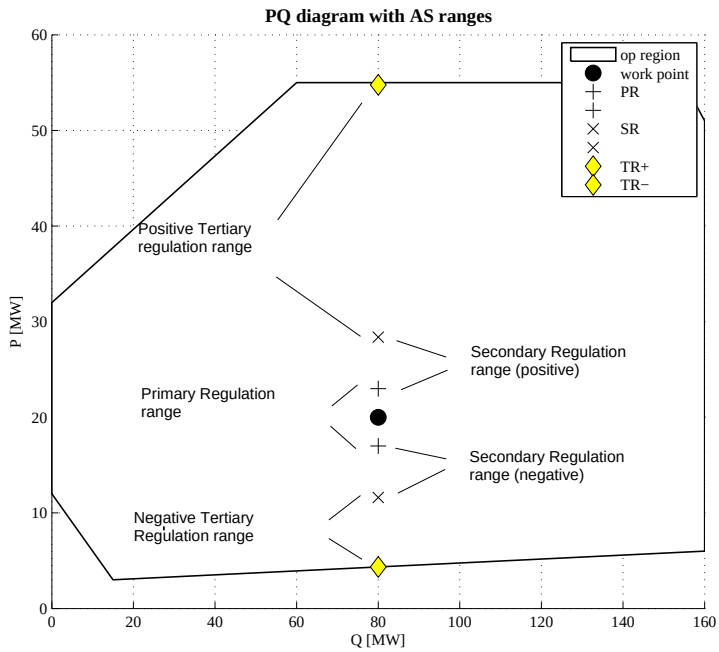

Figure 4.5: AS ranges on a PQ diagram. The full reserved capacity is marked by a point for each AS. The cost of activation of a AS in the profit maximization criterion is equal to cost at this operating point. The *work point* marks the operating point of the turbine when no AS are activated.

4.3.2 One Hour Model

For notation in this section, the reader is referred to Table 2 in the Nomenclature section.

In the one hour model, several operating points need to be considered. By operating point we mean a point in the PQ diagram of a turbine TG represented by the coordinates (q, p, qc) where q is the amount of heat produced, p is the amount of electricity produced and qc is the necessary amount of steam at the input of the turbine. If an AS is activated, the operating point moves into a new position that has the same q coordinate but a different p coordinate and represents the production of electricity at the previous operating point plus the amount of electricity provided as regulation energy for the AS. This is shown in fig. 4.5: the full reserved capacity of each AS is represented by a point and all these points are on a straight line (There are two points for PR and SR as they can be activated in any interval between their negative full capacity and positive full capacity). The *work point* shows the operating point of the turbine when no AS are activated. Naturally, after activation, for each of the points shown in fig. 4.5 the fuel cost is also different due to the increased amount steam required at the input of the turbine (qc coordinate). We need to know where the operating points of activated AS are for two reasons:

- The qc coordinate gives us information about the costs at the operating point when an AS is activated and lets us weight it in respect to the income from activation to determine the optimal capacity that should be offered
- The qc coordinate also gives us the amount of steam at the input of the turbine necessary to provide the required amount of electricity for the AS. The change from working point to the new operating point is subject to dynamical constraints related to the speed of steam boilers.

In case of Primary Reserve there is no income for activation of this AS. Usually, some amount of this service is activated continuously to provide balance control. For Secondary regulation, any amount of electricity between the negative value and positive value of reserved capacity can be activated. However, for simplicity, we consider in this work that that SR is provided at full amount when activated. Positive and negative Tertiary regulation are activated always at full capacity. Therefore five operating points need to be considered:

- the operating point when no AS is activated.
- the operating point for full positive capacity of SR.
- the operating point for full negative capacity of SR.

- the operating point for full capacity of TR+.
- the operating point for full capacity of TR-.

Each of these five operating points is characterized by a convex combination of points forming the PQ diagram. Each of the operating points requires a different amount of steam at the input of the turbine. Therefore, five sets of variables for the steam boilers PK need to be considered subject to speed of change in production constraints.

For an operating point wp, when no AS are activated, that is characterized by $(Q(wp)_{tgi},\ P(wp)_{tgi},\ Qc(wp)_{tgi})$ several constraints apply. The sum of the coefficients of the convex combination of the operating point, must be equal to the operating state of the turbine:

$$\sum_{n=1}^{N} x_{tgi}^{n}(wp) = u_{tgi}.$$

Because of the properties of convex combination, all elements of the vector must be greater or equal to zero:

$$x_{tgi}^{n}(wp) \geq 0 \qquad \forall n = 1...N,$$

and the scalar multiplications of the convex combination coefficients with the operating point vectors are equal to the electrical energy and heat produced and to the input steam necessary to produce them:

$$\begin{aligned}
\mathbf{p_{tgi}x_{tgi}}(wp) &= P_{tgi}(wp) \\
\mathbf{q_{tgi}x_{tgi}}(wp) &= Q_{tgi}(wp) \\
\mathbf{c_{tgi}x_{tgi}}(wp) &= Qc_{tgi}(wp).
\end{aligned}$$

The fuel characteristic of steam boiler PK_j is specified as a piece-wise linear (PWL) function with M intervals:

$$Cost(wp)_{PKj} \geq k_m Q_{PKj}(wp) + b_m u_{PKj} \qquad \forall m = 1...M.$$

with steam production being non zero only when the steam boilers are in *on* state:

$$u_{PKj} Q_{PKj}^{min} \leq Q_{PKj}(wp) \leq u_{PKj} Q_{PKj}^{max}.$$

The steam produced by steam boilers has to be equal to the input steam of the turbines:

$$\sum_i Qc_{tgi}(wp) = \sum_j Q_{PKj}(wp)$$

There will be four other sets of these constraints one for each of the other four points mentioned above. Let's consider a generic positive AS r with capacity of R. The sum of the coefficients of the convex combination that approximates the operating point when the AS is fully activated has to be again equal to the on/off state of the turbine:

$$\sum_{n=1}^{N} x_{tgi}^{n}(r) = u_{tgi},$$

the convex combination coefficients of this operating point must be by the nature of convex combination greater or equal to zero:

$$x_{tgi}^{n}(r) \geq 0 \qquad \forall n = 1...N,$$

the scalar multiplication of this convex combination with the p_{tgi} coordinate must be equal to the amount of electrical energy produced when no AS is activated ($P_{tgi}(wp)$) plus the full capacity of the AS:

$$\mathbf{p_{tgi}x_{tgi}}(r) = P_{tgi}(wp) + R.$$

However, the amount of heat produced at this working point is the same as if no AS was activated:

$$\mathbf{q_{tgi}x_{tgi}}(r) = Q_{tgi}(wp),$$

while the amount of input steam is different:

$$\mathbf{c_{tgi}x_{tgi}}(r) = Qc_{tgi}(r).$$

The same PWL constraints must be applied to the steam boilers for the increased production of steam associated with the activation of the positive AS:

$$Cost_{PKj}(r) \geq k_m Q_{PKj}(r) + b_m u_{PKj} \qquad \forall m = 1...M$$
$$u_{PKj} Q^{min}_{PKj} \leq Q_{PKj}(r) \leq u_{PKj} Q^{max}_{PKj},$$

and the increased steam input at the turbines must be equal to production of steam at steam boilers:

$$\sum_i Qc_{tgi}(r) = \sum_j Q_{PKj}(r).$$

Also, there are ramping constraints on the change of production of steam resulting from AS activation. This change must occur within the time interval allowed for a specific AS to reach full capacity:

$$Q(r)_{PKj} - Q(wp)_{PKj} \leq r_{time} \Delta(up)_{PKj}$$

As shown in fig. 4.5 the considered sequence of activation is PR, SR, TR which often corresponds to real life situations. Therefore, the sum of the positive AS and the amount of electrical energy produced when no AS are activated must be equal to the amount of electrical energy produced at the operating point where full capacity of TR_+ is activated. This point is given by the scalar multiplication of the p_{tgi} working point vector with the convex combination $\mathbf{x}_{tgi}(TR_+)$:

$$PR_{tgi} + SR_{tgi} + TR_{+tgi} + P_{tgi}(wp) = \mathbf{p}_{tgi} \mathbf{x}_{tgi}(TR_+)$$

The same must be true for the full negative activation of AS and the convex combination $\mathbf{x_{tgi}}(TR_-)$:

$$-PR_{tgi} - SR_{tgi} - TR_{-tgi} + P_{tgi}(wp) = \mathbf{p}_{tgi} \mathbf{x}_{tgi}(TR_-).$$

The previous two constraints also ensure that electricity production stays within bounds of the PQ diagram. This is due to the nature of convex combination which can approximate only points inside and on the sides of the polygon it approximates. Similar

constraints are applied to the positive and negative full capacity of SR. The convex combinations $\mathbf{x}_{tgi}(SR_+)$ and $\mathbf{x}_{tgi}(SR_-)$ determine the operating point where full positive and negative SR capacity is provided (see fig. 4.5):

$$PR_{tgi} + SR_{tgi} + P_{tgi}(wp) = \mathbf{p}_{tgi}\mathbf{x}_{tgi}(SR_+)$$
$$-PR_{tgi} - SR_{tgi} + P_{tgi}(wp) = \mathbf{p}_{tgi}\mathbf{x}_{tgi}(SR_-).$$

The activation of ancillary services is also subject to dynamic constraints of the turbines. PR can be no greater than a technical limit of the turbine:

$$PR_{tgi} \leq MAX(PR)_{tgi}.$$

It must be ensured that in case of full activation of PR (positive or negative), full capacity of SR can be reached within the specified time limit SR_{time}, both positive and negative. This is determined by the minimum of the maximum increase $(\Delta(up_{max})_{tgi})$ and decrease $(\Delta(down_{max})_{tgi})$in production of a given turbine:

$$PR_{tgi} + SR_{tgi} \leq min\left(\Delta_{tgi}(up), \Delta_{tgi}(down)\right) SR_{time}.$$

It must be also ensured that the full capacity of TR_+ or TR_+ must be reached within the specified time limit (TR_{+time},TR_{-time}) even in case of full activation of positive or negative PR and SR respectively:

$$PR_{tgi} + SR_{tgi} + TR_{+tgi} \leq \Delta_{tgi}(up)TR_{+time}$$
$$PR_{tgi} + SR_{tgi} + TR_{-tgi} \leq \Delta_{tgi}(down)TR_{-time}.$$

The ancillary services offered of the market are the sum of the AS on the turbines:

$$PR = \sum_i PR_{tgi}$$
$$SR = \sum_i SR_{tgi}$$
$$TR_+ = \sum_i TR_{tgi}$$
$$TR_- = \sum_i TR_{tgi}$$

Some AS could already have been sold on a longterm basis and therefore have to be provided (e.g. PR_{req}). Also there might be a certain upper limit for AS that can be placed on the market (e.g. SR_{max}).

$$PR_{req} \leq PR \leq PR_{max}$$
$$SR_{req} \leq SR \leq SR_{max}$$
$$TR_{+req} \leq TR_{+} \leq TR_{+max}$$
$$TR_{-req} \leq TR_{-} \leq TR_{-max}$$

Finally, the constraints related to the to peak heat boilers HK_l are:

$$COST_{HKl} \geq k_l Q_{HKl} + b_l u_{HKl}$$
$$u_{HKl} Q^{min}_{HKl} \leq Q_{HKl} \leq u_{HKl} Q^{max}_{HKl}$$

The total heat produced during one time interval is equal to the sum of heat production at turbines and peak heat boilers (when delivered heat is considered the inflows and outflows of the heat storage are added to the right hand side of the equation):

$$Q_{prod} = \sum_i Q_{tgi}(wp) + \sum_i Q_{HKl}.$$

The total amount of electricity produced (if no AS are activated) is:

$$\sum_i P(wp)_{tgi} = P_{req} + \sum_n P_{contr\,n} + dev$$

4.3.3 Multiple Hour Model

For notation in this section, the reader is referred to Table 3 in the Nomenclature section.

The multiple hour model consists of several one hour models that are linked together by dynamical constraints. Three types of dynamical constraints are considered:

- minimum up and down times
- ramping constraints between hours

- heat storage

The minimum up and down constraints are applied to binary vectors that represent the operating states (on or off) of units. For a unit o and the time t, these constraints can be represented as:

$$\sum_{i=t}^{t+MUT_o-1} u(i)_o \geq MUT_o start_o^t$$
$$\sum_{i=t}^{t+MDT_o-1} u(i)_o \geq MDT stop_o^t$$

Ramping constraints apply to the changes in production of all units between neighboring hours and can be expressed as:

$$Pr_o^{t+1} - Pr_o^t \leq \Delta_o(up) time_o(up)$$
$$Pr_o^{t+1} - Pr_o^t \geq -\Delta_o(down) time_o(down)$$

Finally, the content of the heat storage can be expressed as:

$$Q_{cnt}^{t+1} = Q_{cnt}^t - Q_{st\ flow}^t - Q_{loss}^t$$

The mathematical model was implemented in MATLAB with the help of YALMIP (Löfberg, J., 2004), an efficient language for rapid prototyping of optimization problems.

4.4 Conclusion

In the first part of this chapter, a case study was presented that corresponds to a typical configuration of a cogeneration plant in Central Europe. The choice of methods applicable to production planning of this system was discussed and a mixed integer linear programming formulation was selected that can be solved by the Branch & Bound method. In the second part of the chapter a mathematical model for scheduling of the case study system was formulated. Two optimization criteria were described, one for operational

cost minimization and the second one for expected profit maximization. Subsequently, a model for solution of the one hour production planning problem was formulated. In the final part, dynamical constraints were set up that link multiple instances of the one hour problem into a multiple hour model.

Chapter 5

Experimental Results

In this chapter, results for the case study defined in section 4.1 in the previous chapter will be presented. The multiple hour model has a very large number of parameters and due to ramping constraints and minimum up and down time constraints the results are sometimes difficult to interpret. Therefore, in the first section of this chapter, some illustrative examples will be presented to expose the more more complicated profit maximization criterion. This will hopefully make the results of the multiple hour planning model presented in section more understandable. The final section will address briefly the computational demands of the scheduling task.

5.1 One Hour Model

The optimization criterion for the cost minimization is fairly straight forward - the fuel cost of the boilers is minimized. However, the criterion for profit maximization is more complicated due to the large number of parameters that enter it: power prices, reservation prices, activation prices and activation probabilities. In this section, examples will be provided to show how changes in these parameters can influence the optimal product mix of energy and AS contracts to be sold. The one hour model was selected for this purpose because it is more straight forward than the multiple hour model.

Test Case 1

This test case shows how production of electricity can be substituted by provision of Ancillary services. AS represent power generating capacity that is kept available. Hence, a generating company has a choice between using its production assets for generating power or providing AS. This is illustrated in fig. 5.1 which shows the different operating points that maximize expected profit. The plot on the left shows the operating point for electricity production and the point at which regulation energy for AS is provided for the electricity price $p_1 = 1000$ CZK/MWh. The plot on the right shows the same case for the electricity price of $p_2 = 900$ CZK/MWh. We can notice the difference between the suggested energy products that maximize expected profit.

Table 5.1: Parameters for test case 1

Variable	**Description**	**Value**
p_1	power price1	1000 CZK/MWh
p_2	power price2	900 CZK/MWh
pr^{res}_{PR}	PR reservation price	2000 CZK/MW
pr^{res}_{SR}	SR reservation price	1800 CZK/MW
pr^{act}_{SR}	SR activation price	900 CZK/MWh
pr^{res}_{TR+}	TR_+ reservation price	600 CZK/MW
pr^{act}_{TR+}	TR_+ activation price	900 CZK/MWh
pr^{res}_{TR-}	TR_- reservation price	100 CZK/MW
pr^{act}_{TR-}	TR_- activation price	-100 CZK/MWh
$P_{act}(SR)$	probability of activation of SR	0.1
$P_{act}(TR_+)$	probability of activation of TR_+	0.1
$P_{act}(TR_-)$	probability of activation of TR_-	0.1

Test Case 2

In this test case, the influence of the *probability of activation* parameter on the optimal product mix is illustrated. As part of the revenue from ancillary services comes from the activation price, the likelihood of activation is also a factor influencing the choice of the

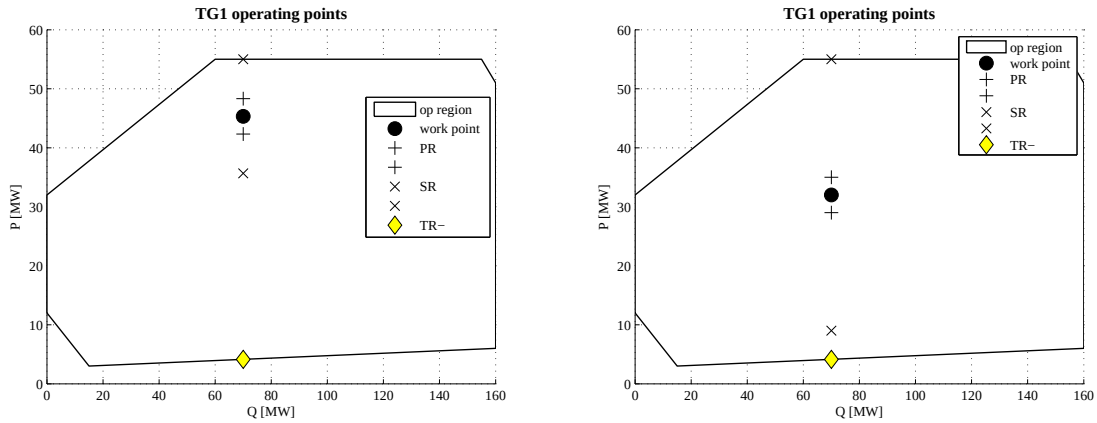

Figure 5.1: Test case 1: PQ diagram of TG1 for different power prices. Higher electricity price (1000 Kc/MWh, left plot) results in more electricity provided, lower price(1000 Kc/MWh, right plot) results in a suggestion to sell more SR

amount of different AS provided and generated electricity . In fig. 5.2, the plot on the left shows operating points for the probability of activation $P_{1act}(SR) = 0.05$ and the plot on the right for the probability $P_{2act}(SR) = 0.3$. In the first case, it is more profitable to generate power while in the second case it is the provision of SR that maximizes expected profit.

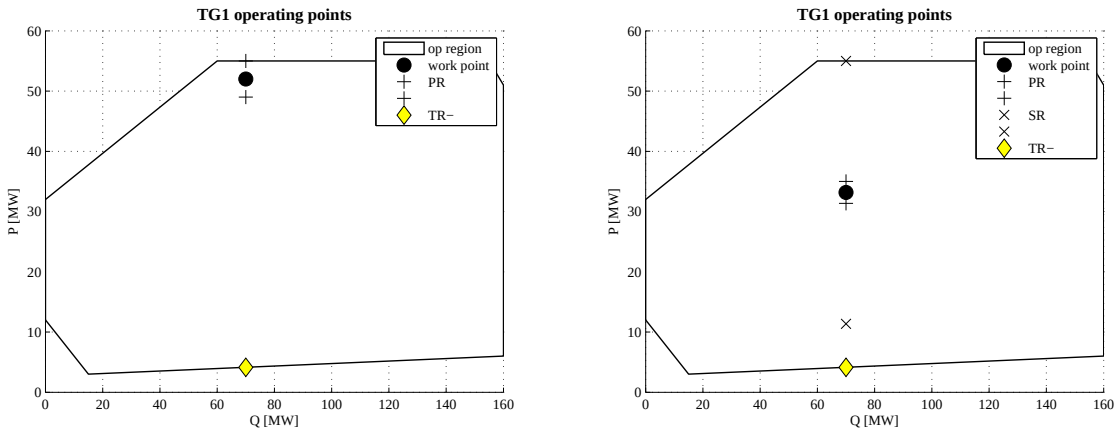

Figure 5.2: Test case 2: PQ diagram of TG1 for different activation probabilities. A lower activation probability ($P_{1act}(SR) = 0.05$, left plot) results in more electricity provided, a higher activation probability($P_{2act}(SR) = 0.3$, right plot) results in a suggestion to sell more SR

Table 5.2: Parameters for test case 2

Variable	Description	Value
p	power price	900 CZK/MWh
pr^{res}_{PR}	PR reservation price	2000 CZK/MW
pr^{res}_{SR}	SR reservation price	1800 CZK/MW
pr^{act}_{SR}	SR activation price	900 CZK/MWh
pr^{res}_{TR+}	TR_+ reservation price	600 CZK/MW
pr^{act}_{TR+}	TR_+ activation price	900 CZK/MWh
pr^{res}_{TR-}	TR_- reservation price	100 CZK/MW
pr^{act}_{TR-}	TR_- activation price	-100 CZK/MWh
$P_{1act}(SR)$	probability of activation of SR	0.05
$P_{2act}(SR)$	probability of activation of SR	0.3
$P_{act}(TR_+)$	probability of activation of TR_+	0.1
$P_{act}(TR_-)$	probability of activation of TR_-	0.1

Test Case 3

In the previous two test cases, the activation and reservation prices were fairly high compared to the production costs. This resulted in the entire available capacity of the turbine being used for AS. This may not always be a case. If the activation price is lower than the highest marginal cost of production of electricity for a particular heat load and the reservation price is not high enough to make up for it, the optimal amount for AS to be sold is not equal to full capacity. In fig. 5.3, the plot on the left shows operating points for $pr_{1act}(TR+) = 200$ CZK/MWh and the plot on the right for $pr_{2act}(TR+) =250$ CZK/MWh.

In the test cases abov, we have seen how different parameters can lead to a different product mix recommended to be sold. In practice, some of these parameters are not known before hand and need to be estimated with a certain degree of uncertainty. Besides the probabilities of activation also energy product prices may have to be subject to an educated guess in some cases (i.e. deciding on a biding price for a particular contract). A small change in parameters can sometimes result in a large change of the suggested

Table 5.3: Parameters for test case 3

Variable	Description	Value
pr^{res}_{PR}	PR reservation price	2000 CZK/MW
pr^{res}_{SR}	SR reservation price	700 CZK/MW
pr^{act}_{SR}	SR activation price	200 CZK/MWh
pr^{res}_{TR+}	TR_+ reservation price	300 CZK/MW
$pr1^{act}_{TR+}$	TR_+ activation price	200 CZK/MWh
$pr2^{act}_{TR+}$	TR_+ activation price	250 CZK/MWh
pr^{res}_{TR-}	TR_- reservation price	100 CZK/MW
pr^{act}_{TR-}	TR_- activation price	-100 CZK/MWh
$P_{2act}(SR)$	probability of activation of SR	0.1
$P_{act}(TR_+)$	probability of activation of TR_+	0.6
$P_{act}(TR_-)$	probability of activation of TR_-	0.6

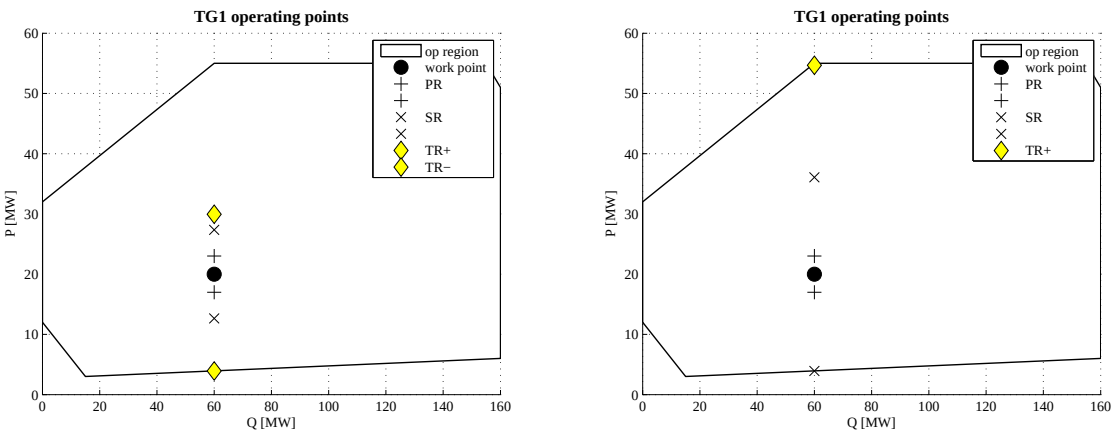

Figure 5.3: Test case 3: PQ diagram of TG1 for different activation prices. A lower activation price ($pr_{1act}(TR+) = 200$ CZK/MWh, left plot) results in less TR_+ to be sold, a higher activation price ($pr_{2act}(TR+) = 250$, right plot) results in a suggestion to sell more TR_+

product mix, without a large change in expected profit. This phenomenon is called *penny-switching* and is inherent to linear programming. As penny switching is not desirable, multiple optimization runs can identify which parameters are relevant for a particular

case and at what values penny switching occurs. This in turn can give some insight into which of the product mixes suggested by the different runs should be finally chosen. For example multiple runs of test case 2 can tell us that penny switching occurs somewhere in the interval (0.2, 0.3) for probability of activation of SR. An expert that knows the current situation on the power market can more easily tell that activation of SR is 'unlikely' ($P_{act}(SR) < 0.2$) or 'possible' ($P_{act}(SR) > 0.3$) than provide an exact estimation of this probability. In this way the appropriate product mix to be sold can be selected (the amount suggested in the left plot in fig. 5.2 in the first case or the amount suggested in the right plot in the second case).

5.2 Multiple Hour Model

In this section we are going to present various test cases for the two scheduling tasks studied, cost minimization and profit maximization. A planning period of 24 hours is considered. The technical parameters and their default values for the multiple hour model are summarized in table 5.4. The presented results were computed using the academic solver SCIP (Achterberg, T., 2007).

Table 5.4: Technical parameters for the multiple hour model

Variable	**Description**	**Value**
h_change	time allowed to change production between hours	10 min
$Q^{in}_{min}(ST)$	minimum input heat flow into the storage tank	0 MW
$Q^{in}_{max}(ST)$	maximum input heat flow into the storage tank	20 MW
$Q^{out}_{min}(ST)$	minimum output heat flow into the storage tank	0 MW
$Q^{out}_{max}(ST)$	minimum output heat flow into the storage tank	20 MW
$Cont_{max}(ST)$	maximum content of the storage tank	10 MW
$Cont_{min}(ST)$	minimum content of the storage tank	150 MW
MUT	minimum up time (same for all units)	3 hours
MDT	minimum down time (same for all units)	3 hours
$COST(SU)$	start up cost (same for all units)	20 000 CZK
$COST(SD)$	shut down cost (same for all units)	20 000 CZK

5.2.1 Cost Minimization

As already mentioned earlier, the goal of the cost minimization task is to compute the optimal unit commitment of all units and their economic despatch that minimizes operational costs while satisfying demand. The scheduling tasks has the following inputs:

- diagram of the predicted heat load that needs to be satisfied
- diagram of required production of electricity that represents long term contracts that have to be met with a possible deviation
- diagram of reserved capacity for ancillary services that represents long term contracts that have to be met
- expected cost of deviation
- fuel costs
- start up and shut down costs for all units
- time limit allowed to change production between hours

In the following lines, two cost minimization test cases will be presented.

Test Case 4

This test case represents simple cost minimization without ancillary services or heat storage. In fig. 5.4 and fig. 5.5 it can be seen that heat load and power demand are satisfied by running TG1 close to its maximum capacity in the backpressure mode and TG2 at a lower capacity. As head demand decreases dramatically after 8 am and the turbines cannot change their production rapidly enough, the cheaper peak heat boiler HK1 is switched on for the minimum amount of time allowed by minimum up constraints. Figure fig. 5.6 shows the production at steam boilers. It can be noticed that the boilers PK1 and PK3 are run at the point where their production is most efficient with the more expensive boilers PK2 and PK4 making up for the rest of the needed steam. The boiler PK2 is switched off during low heat load. With two start start ups and two shut downs, the cost was minimized at 4 029 000 CZK.

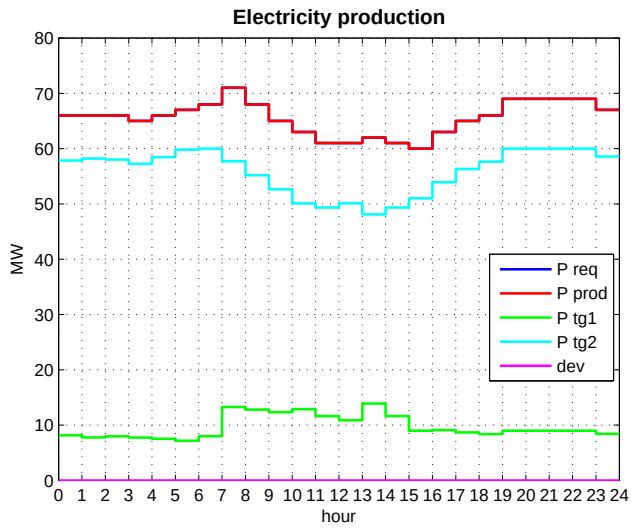

Figure 5.4: Test case 4: Electricity production. *P req* is the required electricity diagram, *P prod* the produced electricity (identical in this case), *P tg1* is the electricity produced on TG1, *P tg2* the electricity produced on TG2 and *dev* the deviation (difference between required diagram and production)

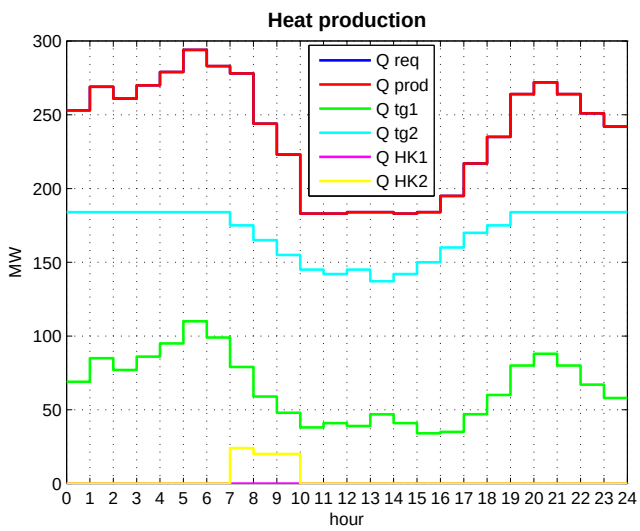

Figure 5.5: Test case 4: Heat production. *Q req* is the required heat load, *Q prod* the produced electricity (identical in this case), *Q tg1* is the heat produced on TG1, *Q tg2* the heat produced on TG2, *Q HK1* is the heat produced on HK1, *Q HK2* the heat produced on HK2.

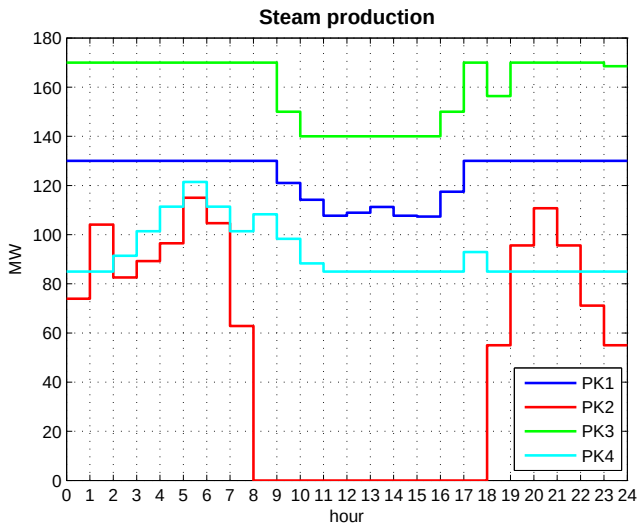

Figure 5.6: Test case 4: Steam production on steam boilers PK1-4

Test Case 5

In this test case the heat storage was included and the same diagram for heat load and power demand was used. It can be seen that electricity production (fig. 5.7) is smoother than in the previous test case, due to the flexibility provided by the heat storage. In heat production, the plan takes ample advantage of the heat storage, filling up the tank at one point to maximum capacity (fig. 5.10). In fig. 5.8 the difference between the heat load (blue) line and heat produced (red line) is made up by the inflows or outflows from the heat storage. As the turbines produce heat more efficiently (notice that the drop in heat production of TG1 is less sharp in fig. 5.8 than fig. 5.5) due to the flexibility provided by the heat storage, less steam is necessary and boiler PK2 can left switched off (fig. 5.9) in contrast with the previous test case. With only one shut down occurring during the planning period, the operational cost was minimized at 3 848 900 CZK.

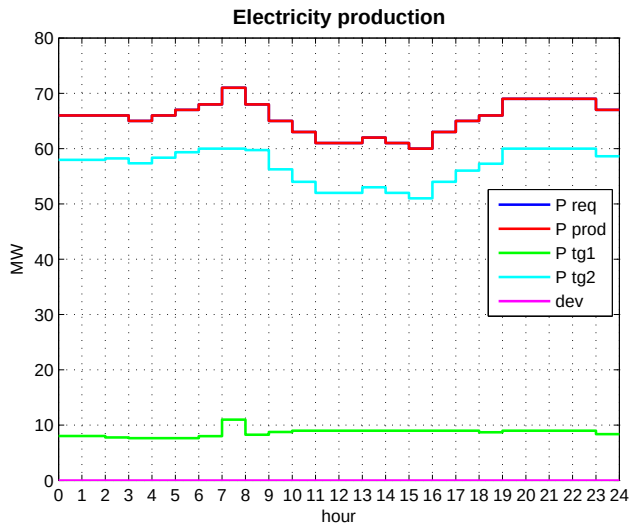

Figure 5.7: Test case 5: Electricity production. *P req* is the required electricity diagram, *P prod* the produced electricity (identical in this case), *P tg1* is the electricity produced on TG1, *P tg2* the electricity produced on TG2 and *dev* the deviation (difference between required diagram and production)

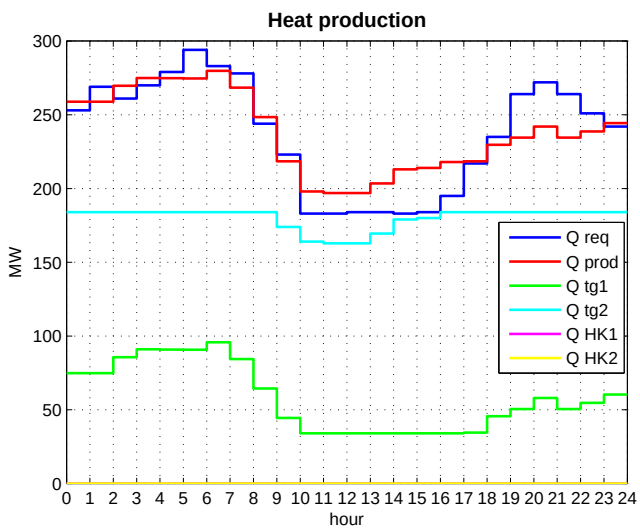

Figure 5.8: Test case 5: Heat production. Test case 4: Heat production. *Q req* is the required heat load, *Q prod* the produced electricity, *Q tg1* is the heat produced on TG1, *Q tg2* the heat produced on TG2, *Q HK1* is the heat produced on HK1, *Q HK2* the heat produced on HK2.

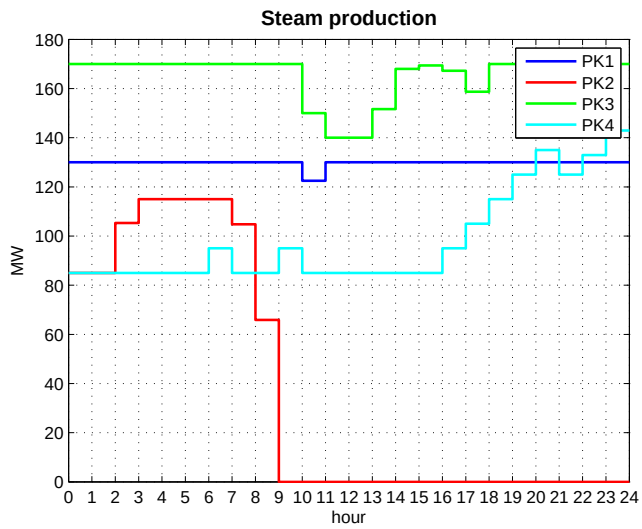

Figure 5.9: Test case 5: Steam production on steam boilers PK1-4

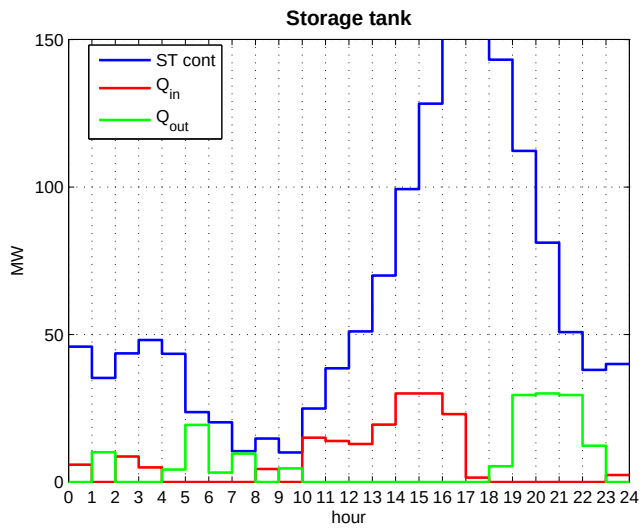

Figure 5.10: Test case 5: Heat storage. The line *ST content* shows content of the storage tank, Q_{in} is input heat flow,Q_{out} the output heat flow

Table 5.5: Profit maximization parameters

Variable	Description	
pr_{long}	price for power from long term power contracts	1000 CZK/MWh
pr_{short}	price for power shor term one hour electricity	900 CZK/MWh
$pr_{baseload}$	price per hour of power delivered	900 CZK/MWh
pr_{peak}	price per hour of power delivered	1800 CZK/MWh
pr^{res}_{PR}	PR reservation price	2000 CZK/MW
pr^{res}_{SR}	SR reservation price	1200 CZK/MW
pr^{act}_{SR}	SR activation price	900 CZK/MWh
pr^{res}_{TR+}	TR_+ reservation price	600 CZK/MW
pr^{act}_{TR+}	TR_+ activation price	900 CZK/MWh
pr^{res}_{TR-}	TR_- reservation price	100 CZK/MW
pr^{act}_{TR-}	TR_- activation price	-100 CZK/MWh
PR_{max}	maximum marketable amount of PR	7 MW
SR_{max}	maximum marketable amount of SR	20 MW
TR_{+max}	maximum marketable amount of TR_+	30 MW
TR_{-max}	maximum marketable amount of TR_-	30 MW

5.2.2 Profit Maximization

As we have already shown in the one hour model test cases, in case of profit maximization, the actual profit of selling electricity contracts has to be weighted against the expected profit from the provision and activation of AS. The added difficulty in the multiple hour model is the fact block products require the delivery of a constant power output. Therefore, in some hours, it is advantageous to give up profitable AS in favor of a multiple hour block power contract. The profit maximization task has the following additional inputs:

- standard block power products considered (e.g. Baseaload, Peak, ...)
- their prices and minimum and maximum amounts marketable at this price
- reservation and activation prices for all considered AS, their minimum amounts and maximum marketable amounts as well as their activation probabilities

Two more test cases are going to be presented that will illustrate the usefulness of weighting AS production costs against expected revenue. The common parameters for both test cases are shown in table 5.5.

Test case 6

In this test case low likelihood of activation of ancillary services is considered. The relevant probabilities are shown in table table 5.6.

Table 5.6: Parameters for test case 6

Variable	**Description**	**Value**
$P_{act}(SR)$	probability of activation of SR	0.01
$P_{act}(TR_{+})$	probability of activation of TR_{+}	0.01
$P_{act}(TR_{-})$	probability of activation of TR_{-}	0.01

In fig. 5.12 the total amount of AS to be sold is shown - as AS prices are favorable the maximum marketable amount is provided with the exception of peak hours. This is due to the high price peak load price which results in a large amount of capacity attributed to this block product, see fig. 5.12. Both Base Load electricity and one hour electricity are produced with one hour power reaching the upper limit allowed. In fig. 5.14 and fig. 5.15, it can be seen how Ancillary services are distributed on the two turbines. During the off-peak hours TR_{-} is provided mainly on TG2. This is due the fact that in case of activation the resulting working point would lead to lower cost on TG2. The situation changes in the peak hours when power output increases dramatically to take advantage of the peak load price. In this case, activation of TR_{-} is more advantageous on TG1. Finally, fig. 5.17 shows how the storage tank is used to exploit peak power prices: during the peak hours it is filled to maximum capacity and heat is released in the off peak hours. The resulting expected operating profit for this schedule is 315 100 CZK.

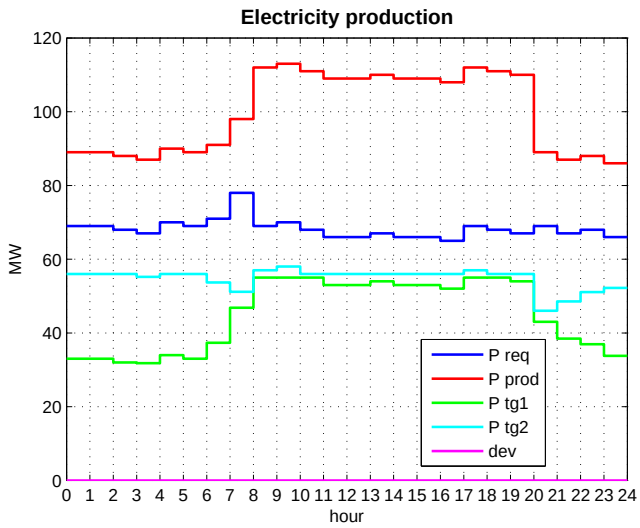

Figure 5.11: Test case 6: Electricity production. *P req* is the required electricity diagram, *P prod* the produced electricity, *P tg1* is the electricity produced on TG1, *P tg2* the electricity produced on TG2 and *dev* the deviation (difference between required diagram and production)

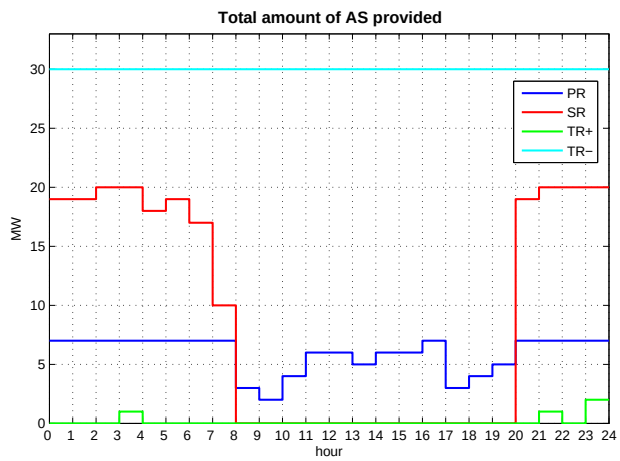

Figure 5.12: Test case 6: Total amount of ancillary services provided

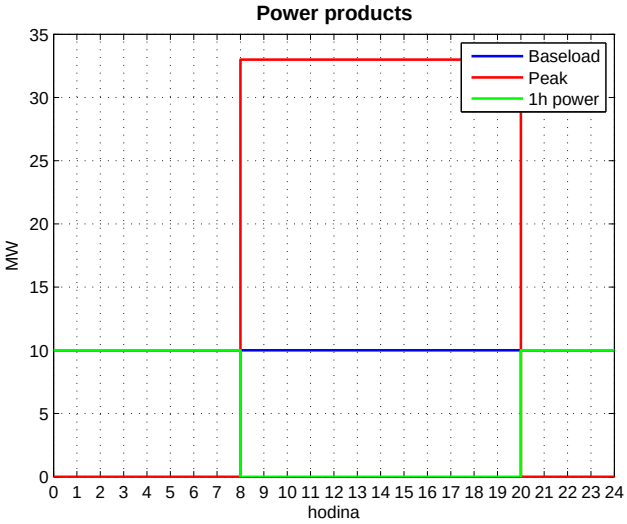

Figure 5.13: Test case 6: Power products recommended for sale

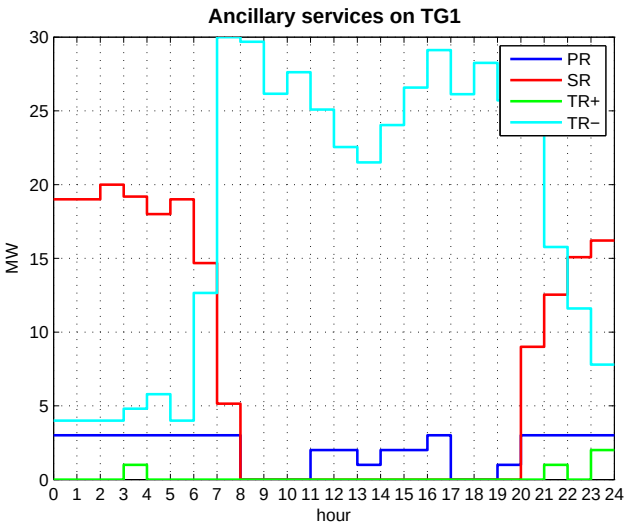

Figure 5.14: Test case 6: Ancillary services on TG1

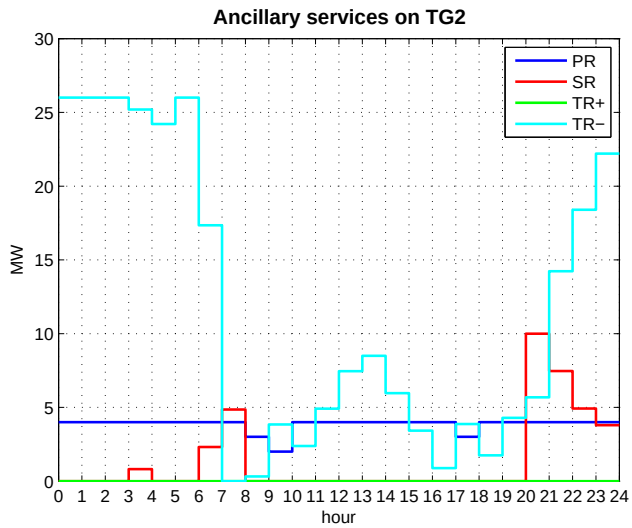

Figure 5.15: Test case 6: Ancillary services on TG2

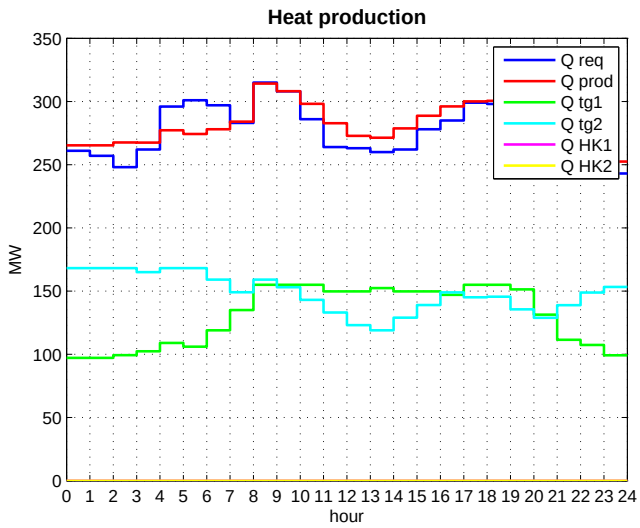

Figure 5.16: Test case 6: Heat production. *Q req* is the required heat load, *Q prod* the produced electricity, *Q tg1* is the heat produced on TG1, *Q tg2* the heat produced on TG2, *Q HK1* is the heat produced on HK1, *Q HK2* the heat produced on HK2.

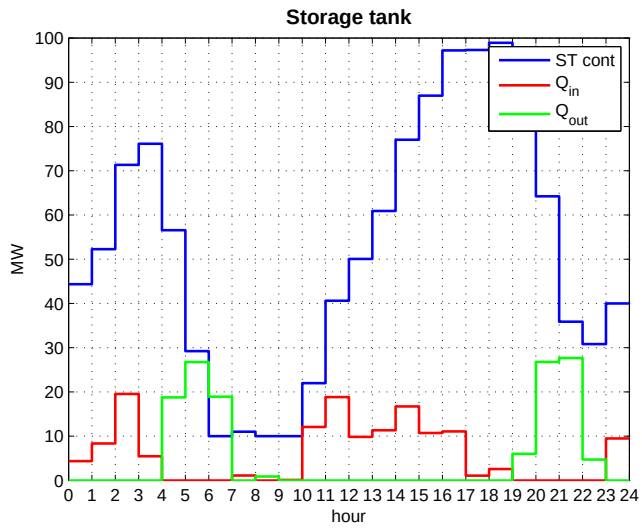

Figure 5.17: Test case 6: Heat storage. The line *ST cont* shows content of the storage tank, Q_{in} is input heat flow,Q_{out} the output heat flow

Test Case 7

In contrast to the previous test case, a high likelihood of activation of ancillary services is considered (table 5.7).

Table 5.7: Parameters for test case 7

Variable	Description	
$P_{act}(SR)$	probability of activation of SR	0.3
$P_{act}(TR_+)$	probability of activation of TR_+	0.3
$P_{act}(TR_-)$	probability of activation of TR_-	0.3

The increased probability of activation of AS results in the proposition of a different mix of products. It leads to increased expected revenues from AS which become more profitable than in the previous case. More is SR offered along with more TR_+ which was practically nonexistent in the preceding example. Also, in some time intervals the full capacity of TR_- that is marketable is not used up due to the decrease in electricity production. Less electricity is produced (fig. 5.18) resulting in Base Load electricity not

being offered and the spare production capacity is transfered to an increased amount of peak electricity (fig. 5.19). The expected profit of this schedule is 427 600 CZK.

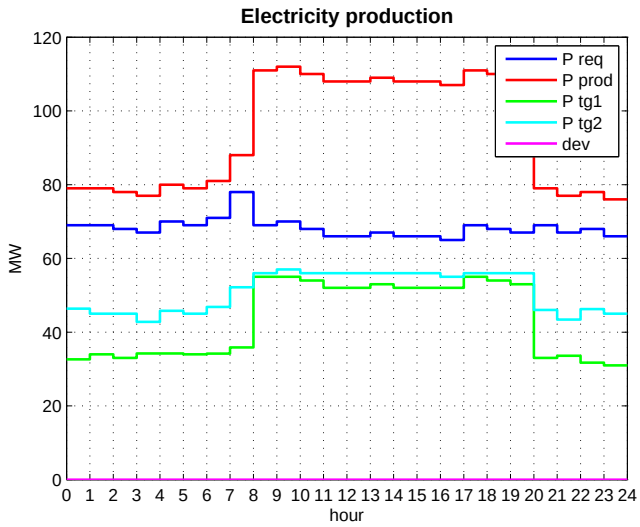

Figure 5.18: Test case 7: Electricity production. *P req* is the required electricity diagram, *P prod* the produced electricity, *P tg1* is the electricity produced on TG1, *P tg2* the electricity produced on TG2 and *dev* the deviation (difference between required diagram and production)

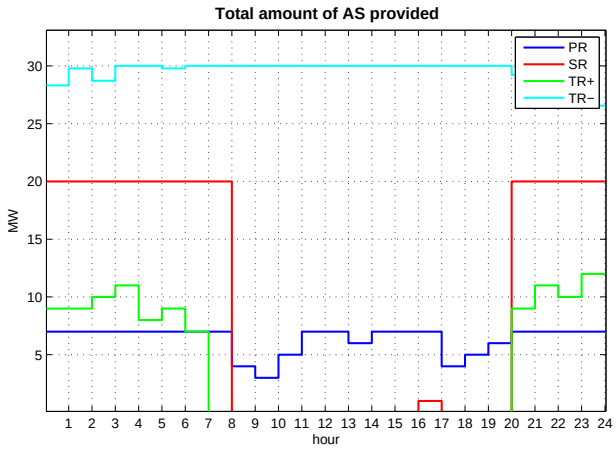

Figure 5.19: Test case 7: Total amount of ancillary services provided

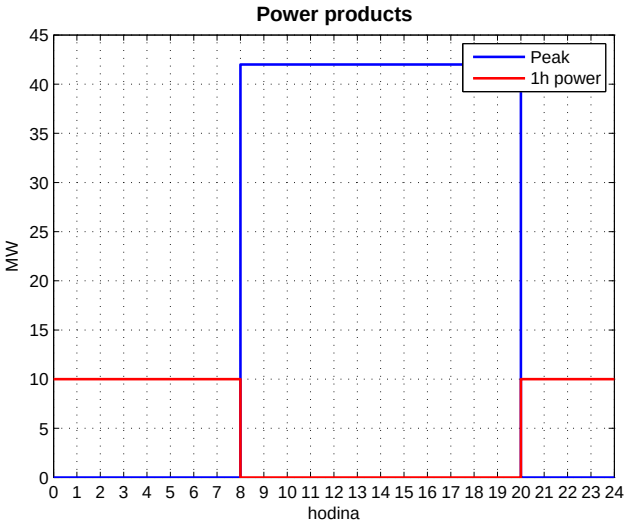

Figure 5.20: Test case 7: Power products recommended for sale

5.3 Computational Complexity

The 24 hour profit maximization and cost minimization are fairly large problems. The number of variables and constraints for each of the multiple hour test cases is shown in table 5.8.

Table 5.8: Number of variables in the presented test cases

Test case	Binary variables	Cont. variables	Constraints
4 & 5	1 176	4 886	15 979
6 & 7	1 176	5 200	16 319

The test cases presented in the previous section were run on an Intel T5250 processor with 1 GB of RAM. Table table 5.9 presents a summary of the computation times for the multiple hour test cases (One hour test case are not included as they are always solved within one second).

Table 5.9: Computational complexity of the presented test cases

Test case	**Amount of time [sec]**
4	219
5	231
6	62
7	40

Several observations can be made about the computational time. Firstly, the execution time depends on the heat demand. For some heat demands, the determination of the unit commitment of various units is straight forward. For others, demand at particular hours may be at points where the marginal costs of units are similar which requires more branching of the B&B algorithm. This results in higher execution time. Secondly, more restrictive ramping constraints and minimum up and down time constraints speed up the execution time, as the part of the search space that is feasible decreases. Thirdly, cost minimization takes longer as there is less degrees of freedom and the solver has to work hard to ensure that demand is satisfied. In profit maximization it is often easier to determine the direction of the search (e.g. electricity prices are higher so ramping up production increases profit).

The computational time results can be considered as very encouraging. They suggest that it would be feasible to compute multiple scenarios for different values of uncertain parameters for a real life CHP plant. Several probabilities of activation could be tried to check for existence of points where penny switching occurs. Different prices could be investigated to support bidding strategies in power exchanges. The impact on profits of an incorrect prediction of heat load could be estimated as well by trying slightly lower and higher variations of the predicted heat load. In this way risks resulting from an incorrect prediction of heat demand, such having to commit another heat unit for a short time and thus incurring start - up and shut down costs, could be minimized. The reader should note that re optimizing the model for different values of parameters is a task that could be implemented in a parallel way relatively easily. In this manner, the computational complexity could be spread on a multi core processor.

Chapter 6

Conclusion

A short term scheduling of a cogeneration system has been addressed in this thesis. A factor that was considered very important in this work was the global optimality of solution. For this reason Exact methods were preferred. Their application was feasible due to a relatively short time horizon in short term scheduling and a lower number of units. The problem was linearized and the Branch and Bounds algorithm was selected as solution method. The main reason for this choice was the availability of fast general purpose solvers that implement this method and of effective tools that allow formulation of large scale mathematical models.

A mathematical model was built that includes steam boilers, peak heat boilers, extraction turbines and a heat storage. Besides the working area constraints of the units the model includes constraints for Ancillary services and three types of dynamical constraints, ramping constraints, minimum up and down times and heat storage constraints linking heat production between hours. Two optimality criteria were defined, one for cost minimization and one for profit maximization. The profit maximization criterion considers revenues and costs both from reservation and expected activation of Ancillary services. As it is not known beforehand what Ancillary services will be activated and when, the revenues and costs of activation are weighted by a coefficient called the *probability of activation*. The inclusion of Ancillary services into the short term production planning problem represents the main contribution of this work.

The resulting problem formulation has been tested on case study that represents a typical configuration of a cogeneration plant in Central Europe. The system consisted of four heat boilers, two extraction turbines, two peak heat boilers and a heat storage. Two test cases were presented for cost minimization and two for profit maximization. A general purpose solver was used to solve both tasks for this system for a planning

period of 24 hours. The results were very satisfying with most test runs finding an optimal solution within four minutes and often during much less time. The speed of the production planning procedure is very important as the profit maximization scheduling task requires a relatively large number of parameters, some of which are uncertain. It allows rapid reoptimization of the problem with different parameters enabling the user to select a schedule that maximizes expected profit with minimal risk.

This work can be extended in several directions. First of all, deviation resulting from production changes between hours could be taken into account. Secondly, non convex fuel characteristics of boilers could be added to the problem. Thirdly, power exchanges could be explored into more depth and additional features could be added that would allow efficient participation in exchange trading such as the generation of optimal bid curves. Finally, it is very likely that the considered mixed integer linear programming problem has a lot of special structure that could be exploited to speed up the optimization dramatically. Therefore, the ultimate extension of this work would be to implement a customized Branch and Bound procedure along the lines of the work presented in (Rong, A. and Lahdelma, R., 2007).

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Appendix A

Appendix 1

A.1 Working points for turbines TG1 and TG2

Table A.1: Working points of turbine TG1

Working point	**Power [MW]**	**Heat [MW]**	**Steam at input [MW]**
P1	9	34	52
P2	4	15	52
P3	312	0	52
P4	36	160	243
P5	51	160	258
P6	57	155	257
P7	57	60	239
P8	32	0	135

Table A.2: Working points of turbine TG2

Working point	**Power [MW]**	**Heat [MW]**	**Steam at input [MW]**
P1	4	0	52
P2	4	39	52
P3	13	38	53
P4	13	0	52
P5	27	0	105
P6	63	90	233
P7	4	184	252
P8	43	117	167
P9	63	184	265

Appendix B

Contents of the enclosed CD

The enclosed CD contains the text of this work in pdf format
(*Simovic_2008_Opt_prod_planning_CHP.pdf*)