Market and Environmental Dispatch of Combined Cycle CHP Plant

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***Abstract* — This paper considers economic dispatch and unit commitment of the combined cycle (CCGT) CHP plant in electricity market conditions and taking into account new environmental challenges. The proposed algorithm was verified on example of CCGT CHP plant.**

***Index Terms*— CHP plants (cogeneration), economic dispatch, production simulation, quadratic equations, Monte Carlo method.**

I. Introduction

DEVELOPMENT of cogeneration power plants is especially supported in the European Union because it allows saving considerable amounts of energy resources, enhancing security of electricity supply and substantially reducing harmful emissions into the atmosphere, especially those of greenhouse effect gases.

New market instruments are being looked for in order to support cogeneration. In some countries, for instance in Denmark and Finland, mandatory electricity purchase and regulated feed-in tariffs, which provided guaranteed profits for cogeneration plants but in fact distorted the market, were abolished. Instead of the old support scheme, there were proposed new ones, such as subsidies for investments, premiums, capacity purchases, tenders, certificates, tax exemptions.

The main difference is that the just mentioned schemes cover only a part of costs but the rest is to be earned by the cogeneration plant owner himself by selling electricity on the free market. This means that neither electricity amount to be sold, nor electricity prices are known beforehand.

This makes optimisation of the cogeneration plant operating regimes by far more complicated stochastic task. In order to address this issue, there is a need to work out new methods, which would allow creating the model of electricity trading from cogeneration plant in a SPOT electricity market [1].

There is another important issue that makes development of model for optimisation of operating regimes of cogeneration plants more complicated [2]. This is CO_2 emissions trading when fossil fuel power plants are obliged to buy necessary emission quotas (allowances) in the market. The price for CO_2 emission allowance is a variable value whereas their necessary amount depends on the amount of electricity to be sold on the market and consumed fuel amount.

In order to make a right decision, while choosing the best trading strategy, optimal unit commitment and unit dispatch, an optimisation model is necessary [3], [4], [5].

II. Formulation of the Objective Function

Main targets for short term optimisation of cogeneration power plants are selection of optimal unit combination (unit commitment) and optimal allocation of load between selected units (unit dispatch). The purpose of economic dispatch of cogeneration power plants is to satisfy electric and heat demand at minimum cost or maximum profit.

The objective function of cogeneration power plant could be formulated as the sum of cost functions of its separate elements. Minimisation of the objective function of cogeneration power plant with cogeneration unit and heat only boilers could be represented as following [6]:

$$C_{CHP} = \min \sum_{t=1}^{n_t} \left[\begin{array}{l} \Pi_{PEt} N_{PEt} + \\ + \sum_{y=1}^{n_{COG}} \left(\begin{array}{l} C_y\left(N_t^y, Q_t^y\right) \cdot w_{yt} \\ + C_{Start}^y \cdot v_{yt} + C_{Stop}^y \cdot u_{yt} \end{array} \right) + \\ + \sum_{x=1}^{n_{HOB}} C_x\left(Q_t^x\right) \end{array} \right] \quad (1)$$

where

n_t - number of time intervals with duration t;

Π_{PEt} - cost of purchased electricity for time interval t_n;

N_{PEt} - volume (capacity) of purchased electricity at the time interval t_n;

$C_y\left(N_t^y, Q_t^y\right)$- cost function of "y" cogeneration unit as a function of electric N_t^y and heat Q_t^y capacity of this particular unit at the time interval t_n;

w_{yt} - binary variable, which describes the operating status of the unit ("0" – out of operation, "1" – in operation);

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n_{COG} - number of cogeneration units;

C^{y}_{Start}, C^{y}_{Stop} - start-up and shut-down costs of "y" cogeneration unit;

v_{yt} - binary variable, which is superior than "0", if "y" unit was started;

u_{yt} - binary variable, which is superior than "0", if "y" unit was stopped;

$C_x\left(Q^x_t\right)$ - cost function of heat only boiler "x";

n_{HOB} - number of heat only boilers.

Start-up costs for the (C_{Start}) for the time interval could be calculated according to formula:

$$C_{Start} = \sum_{t=1}^{n_{Start}}\left[\sum_{i=1}^{n_{CHP}}\left(B_{it}C^{t}_{FUEL} + E^{CO_2}_{it}\Pi^{CO_2}_{t}\right)\right] \tag{2}$$

where n_{Start} is start-up time;

B_{it} - fuel consumption of the unit at the time interval t_n;

C^{t}_{FUEL} - fuel cost;

$E^{CO_2}_{it}$ - CO_2 emission volumes at time period t_n;

$\Pi^{CO_2}_{t}$ - CO_2 emission allowance cost.

Similar formula could be used for calculation of shutdown costs (C_{Stop}).

Binary variable v_{yt} indicates, that cogeneration unit "y" was started at the time interval t_n, if $v_{yt} > 0$, but binary variable u_{yt} - that the unit was stopped, if $u_{yt} > 0$. It is possible to express it as following:

$$v_{yt} = w_{yt} - w_{yt-1} \tag{3}$$

$$u_{yt} = w_{yt-1} - w_{yt} \tag{4}$$

Cogeneration power plant, which sells electricity in the SPOT market, would like to maximise its profit [7]:

$$P_{CHP} = \max\sum_{t=1}^{n_t}\phi_s\left[\begin{array}{l}\Pi^{s}_{Et}\sum_{y=1}^{n_{COG}}N^{y}_{t}w^{s}_{yt} + \\ +\Pi_{Qt}\left(\sum_{y=1}^{n_{COG}}Q^{y}_{t}w^{s}_{yt} + \sum_{x=1}^{n_{HOB}}Q^{x}_{t}\right) - C_{CHP}\end{array}\right] \tag{5}$$

where

Π^{s}_{Et} - electricity SPOT price for t_n in scenario s (we assume that t_n is relatively short and price will not change within t_n);

Π_{Qt} - heat price or tariff at the begin of t_n;

w^{s}_{yt} - binary variable of CHP status;

C_{CHP} - cost function of cogeneration power plant according to (1).

Formula (5) could be simplified and rewritten in the following form:

$$P_{CHP} = \max\sum_{t=1}^{n_t}\phi_s\left[\Pi^{s}_{Et}N^{SPOT}_{Et} + \Pi_{Qt}Q_{Ht} - C_{CHP}\right] \tag{6}$$

where

N^{SPOT}_{Et} - electricity sales volume (capacity) in the SPOT market according to (11);

Q_{Ht} - heat capacity sales in the heat market, according to (12) or (21).

In case, trading portfolio of a cogeneration power plant includes a bilateral power purchase agreement (PPA) with a fixed volume N^{PPA}_{Et} and price Π^{PPA}_{Et}, certain part of a power plant capacity, say N^{SPOT}_{Et}, the owner is planning to sell in the SPOT market at a forecasted price Π^{s}_{Et} (with probability of ϕ_s), but the rest to be offered to transmission system operator ($N^{AUX}_{Et} = N^{\max}_{t} - N^{SPOT}_{Et} - N^{PPA}_{Et}$) as a spinning reserve at the price Π^{AUX}_{Et}, than profit maximisation task could be specified as following:

$$P_{CHP} = \max\sum_{t=1}^{n_t}\phi_s\left[\begin{array}{l}\Pi^{PPA}_{Et}N^{PPA}_{Et} + \Pi^{s}_{Et}N^{SPOT}_{Et} + \\ +\Pi^{AUX}_{Et}N^{AUX}_{Et} + \Pi_{Qt}Q_{Ht} - C_{CHP}\end{array}\right] \tag{7}$$

Let's name this task as the ***"market dispatch"***.

European Union Emission trading scheme (EU ETS) has significantly influenced the logic of power plant operating regime planning and control. The objective function shall be supplemented with additional costs associated with the purchase of CO_2 emission allowances:

$$C_{CHP} = \min\sum_{t=1}^{n_t}\left[\sum_{y=1}^{n_{COG}}\left(\begin{array}{l}C_y\left(N^{y}_{t}, Q^{y}_{t}\right)\cdot w_{yt} + C^{y}_{Start}\cdot v_{yt} + \\ +C^{y}_{Stop}\cdot u_{yt} + \Pi^{CO_2}_{yt}E^{CO_2}_{yt}\end{array}\right)\right] \tag{8}$$

where

$\Pi^{CO_2}_{yt}$ - CO_2 emission allowance price at time interval t_n;

$E^{CO_2}_{yt}$ - CO_2 emission volumes at the time interval t_n, according to formula:

$$E^{CO_2}_{ij} = u_0 + u_1B_{ij} + u_2\left(B_{ij}\right)^2 \tag{9}$$

During the second emission trading period (2008-2012), free emission quotas to certain extent will be available for electricity producers, while during the third trading period (starting from 2013) all the quotas in the electricity sector would be sold in the auction. So, during 2008-2012 electricity producers still would have a choice to produce electricity (and heat) and spend their CO_2 emission quotas or to stop production and got profits from CO_2 emission trading. The decision could be made based on analysis of electricity and emission allowance prices. The objective function for this case could be expressed as following, taking into account (5) & (8):

$$P_{CHP} = \max \sum_{t=1}^{n_t} \phi_s \left[\begin{array}{l} \left(\Pi_{Et}^{s} \sum_{y=1}^{n_{COG}} N_t^y + \Pi_{Qt} \sum_{y=1}^{n_{COG}} Q_t^y \right) \cdot w_{yt}^s + \\ + \Pi_{yt}^{CO_2} \sum_{y=1}^{n_{COG}} E_{yt}^{CO_2} \cdot \left(1 - w_{yt}^s\right) - C_{CHP} \end{array} \right] \quad (10)$$

Let's call this case the ***"environmental dispatch"***.

It assumes profit maximisation from electricity and heat production or alternatively from trading of CO_2 emission quotas. Binary variable $\left(1 - w_{yt}^s\right)$ would have an opposite meaning in comparison to w_{yt}^s: if $w_{yt}^s = 0$, than $\left(1 - w_{yt}^s\right) = 1$. So it shall indicate whether the unit is in operation and consuming CO_2 emission allowances or it is out of operation and is capable to sell quotas.

When calculating the objective function, it is necessary to take all the constraints into account, including CO_2 emission constraints. If necessary, other, regular emissions (NO_x, SO_2, particles, etc.) could be taken into account during the environmental dispatch.

Performing minimisation of the objective functions (1) and (8) or maximisation of the objective functions (5), (7) and (10), it is necessary to take global and local constraints into account. Electricity and heat balances of a cogeneration system are global constraints, while minimum and maximum capacity of cogeneration units are local constraints. In addition it is possible to define limitations on emission, fuel or energy volume during one hour, day or any other time interval.

Global constraints:

$$N_{PEt} + \sum_{y=1}^{n_{COG}} N_t^y w_{yt} = N_{Et} \ , \quad t = \overline{1,\ldots,n_t} \quad (11)$$

$$\sum_{x=1}^{n_{HOB}} Q_t^x + \sum_{y=1}^{n_{COG}} Q_t^y w_{yt} = Q_{Ht} \ , \quad t = \overline{1,\ldots,n_t} \quad (12)$$

If cogeneration system has a heat accumulator, than heat balance shall be supplemented by capacity (volume) of heat accumulator, in accordance with (21). In case if some part of cogeneration electricity to be traded in the SPOT market (N_{Et}^{SPOT}), another part to be sold according to fixed power purchase agreement (N_{Et}^{PPA}), but unused capacity to be offered to the system operator as auxiliary services, for example as a spinning reserve (N_{Et}^{AUX}), than expression (11) could be transformed to the following one:

$$N_{PEt} + \sum_{y=1}^{n_{COG}} N_t^y = N_{Et}^{SPOT} + N_{Et}^{PPA} + N_{Et}^{AUX} \quad (13)$$

Local constraints:

$$N_{yt}^{\min} w_{yt} \le N_t^y \le N_{yt}^{\max} w_{yt} \ , \quad y = \overline{1,\ldots,n_{KOĢ}} \quad (14)$$

$$Q_{yt}^{\min} w_{yt} \le Q_t^y \le Q_{yt}^{\max} w_{yt} \ , \quad y = \overline{1,\ldots,n_{KOĢ}} \quad (15)$$

$$Q_{xt}^{\min} \le Q_t^x \le Q_{xt}^{\max} \ , \quad x = \overline{1,\ldots,n_{ŪK}} \quad (16)$$

$$V_t^{\min} \le V_t \le V_t^{\max} \quad (17)$$

Emission, energy and fuel consumption constraints could be expressed as following:

$$\sum_{t=1}^{n_t} E_{yt}^{CO_2} \cdot \Delta t \le E_y^{quota} \quad (18)$$

$$\sum_{t=1}^{n_t} N_t^y \cdot \Delta t \le W_{y\max day} \quad (19)$$

$$\sum_{t=1}^{n_t} B_t^y \cdot \Delta t \le F_{y\max day} \quad (20)$$

where

N_{Et}, Q_{Ht} - respectively heat and electric load at time interval t_n;

$N_{yt}^{\min}$, $N_{yt}^{\max}$ - minimum and maximum electric capacity of cogeneration unit "y" at the time interval t_n;

$Q_{yt}^{\min}$, $Q_{yt}^{\max}$ - minimum and maximum heat capacity of cogeneration unit "y" at the time interval t_n;

$Q_{xt}^{\min}$, $Q_{xt}^{\max}$ - minimum and maximum heat capacity of heat only boiler "x" at the time interval t_n;

E_y^{quota} - free CO_2 emission quota (if applicable);

$W_{y\max day}$ - maximum daily generation of the unit "y";

$F_{y\max day}$ - maximum daily fuel consumption of "y" unit;

The volume of heat accumulator during the next hour (V_{t+1}) could be defined as volume during the previous hour (V_t), plus heat production of cogeneration units ($\sum_{y=1}^{n_{COG}} Q_{COGt}^y$) and heat only boilers ($\sum_{x=1}^{n_{HOB}} Q_{HOBt}^x$) minus heat load and (if applicable) fictitious load of gland condenser (summer cooler). In this case heat balance (12) could be transformed to the form:

$$V_{t+1} = V_t + \sum_{y=1}^{n_{COG}} Q_{COGt}^y + \sum_{x=1}^{n_{HOB}} Q_{HOBt}^x - Q_{Ht} - Q_{SCt} \ , \quad t = \overline{1,\ldots,n_t} \quad (21)$$

III. ALGORITHM

The algorithm is made of two cycles (Fig. 1). The inner cycle is intended for profit maximisation of gas turbine and heat recovery boiler as the outer cycle is arranged for profit maximisation of a whole power plant. Number of iterations is to be made until optimisation criteria and are met and then the results are received.

The algorithm starts with entering of input data (tariffs, prices, ambient air temperature, and heat load) and defining constraints (minimal and maximum capacity of equipment). Then the outer cycle starts. By using a random number generator, capacity and fuel consumption of a first heat only boiler are determined at this iteration. Heat loading of a steam turbine is calculated as a difference between the required heat load and capacity of a first heat only boiler multiplied by random number function “rand”. When heat capacity of steam turbine is known, it is possible to calculate its electric capacity and steam consumption of the turbine.

Then the inner cycle starts. The first step makes a split of steam consumption between two heat recovery boilers. For this purpose, the random number generator “rand” is used once again in order to determine steam consumption of the first heat recovery boiler. The rest of the whole steam consumption is ensured with the second heat recovery boiler. In case there is no possibility to ensure steam consumption from a boiler by operating only a gas turbine then supplementary firing is started. Fuel consumption of gas turbines and supplementary firings is calculated. Gas turbine electrical loading is calculated as the function of its fuel consumption. Now, the profit provided by gas turbines and heat recovery boilers can be determined. The calculated profit is compared with that at the previous iteration. If the difference is less than the required criterion then the optimum of the inner cycle has been found and the process is to return to the outer cycle, if not then the process continues with a next iteration. On return to the outer cycle, loading and fuel consumption of the second heat only boiler are calculated to ensure heat balance. Further, the total profit of the plant is calculated. It is compared with the profit at the previous iteration and, on conditions that the optimum is found, the calculation stops and results are printed out.

IV. NUMERICAL EXAMPLE

Let us consider application of algorithm mentioned in the Fig. 1 for cogeneration power plant with installed net electric capacity 144 MW and heat capacity 375 MW. Main components of combined cycle unit of the CHP plant are two gas turbines SGT-800 with capacity 43 MW each, two heat recovery boilers with two loops (steam and thermofication) and with supplementary firing and one backpressure steam turbine MP 24 with installed capacity 54 MW. Heat capacity of cogeneration unit is 142 MW.

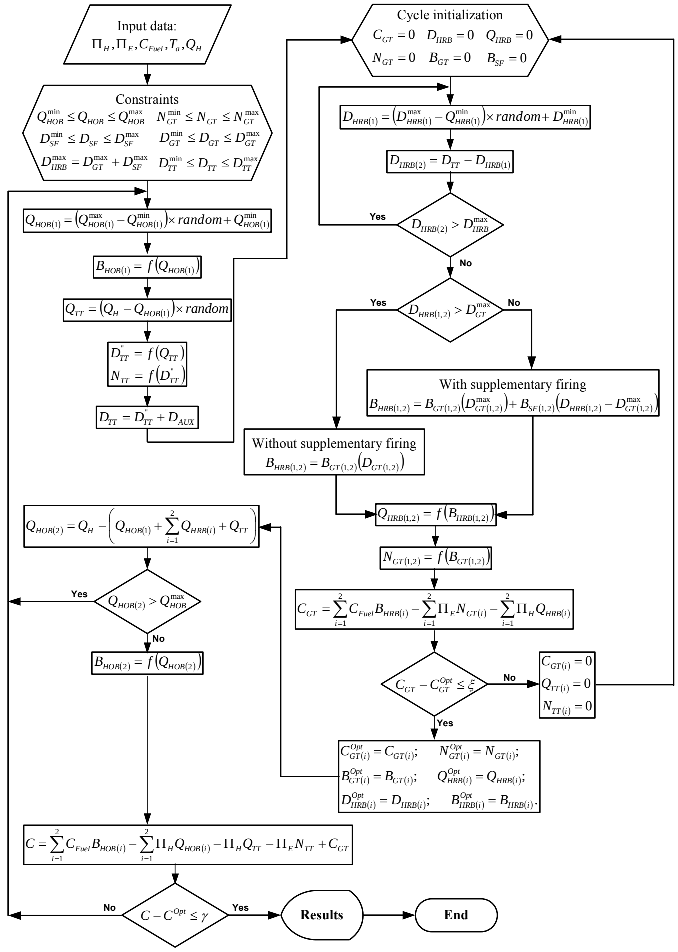

Fig. 1. Optimisation algorithm of combined cycle CHP plant operating regimes

Let us consider the spring regime with the reference to the data recorded on 30 March 2006. Fig. 2 and Fig. 3 compares modelled and reported production schedules of Riga CHP-1 for electricity and heat. Modelled data is indicated with dashed lines. It is possible to conclude, that simulated heat production schedule is almost coincide with the reported data (deviation is only 0,07%), while modelled electricity production schedule is slightly differ from statistics (deviation is 7,5%). The main difference is concerned with operation of gas turbine and supplementary firing units. The model decides to unload one gas turbine in favour of loading the second gas turbine and supplementary firing.

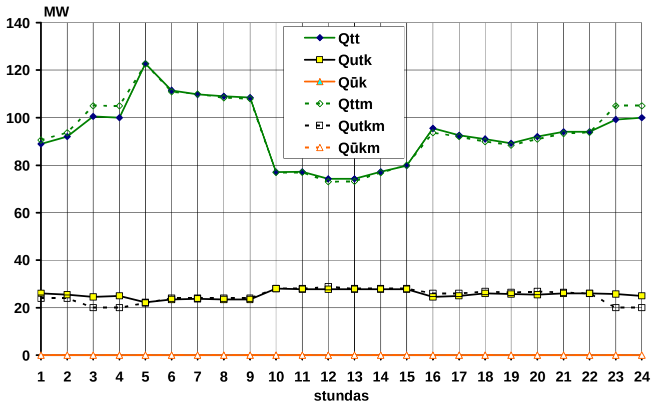

Fig. 2. Heat production schedule (Qtt real heat production from steam turbine, Qttm – optimized. Here and forward all values with "m" are from model, without – from real data)

The selected manner of operation is motivated by fuel savings of about 3,5% for the 24 hours period and which is especially important by CO_2 emission reduction. One of the explanation for such a result is a very low tariff for electricity production (of Riga CHP-1), which discourage from electricity production in cogeneration mode. As the results overall calculated electricity production volumes are lower than actual (Fig. 3).

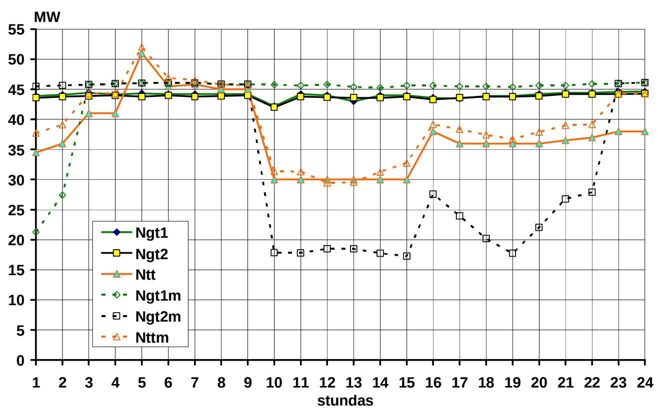

Fig. 3. Electricity production schedule

In the Fig. 4 it is possible to observe, that calculated fuel consumption by supplementary firing is superior, than it was in reality, but fuel consumption of gas turbines is lower.

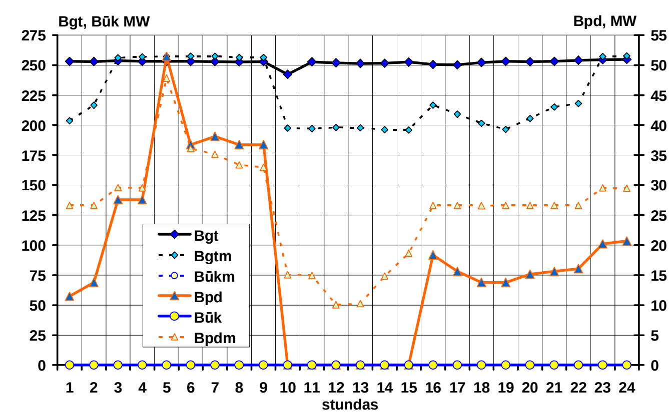

Fig. 4. Fuel consumption volumes

Due to overall reduction of fuel consumption, there is reduction of CO_2 emission volumes (Fig. 5).

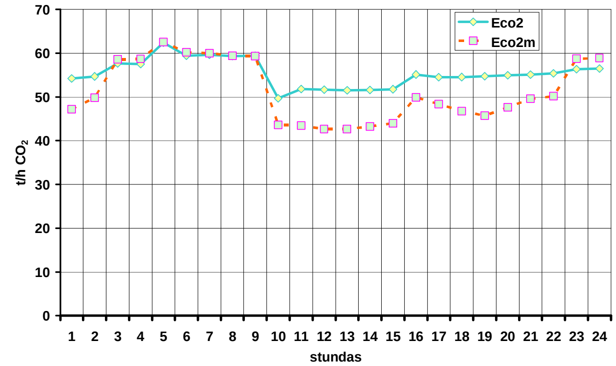

Fig. 5. CO_2 emission volumes

Taking into account the reduction of electricity production volumes in calculated schedule, modelled overall revenues are lower than of reported data (Fig. 6). However, lower are also production costs due to fuel savings.

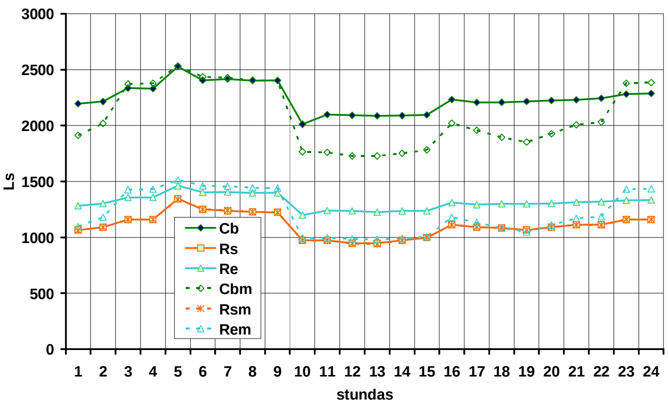

Fig. 6. Revenues and costs

As we consider the total results, the calculated profit is higher than reported profit (Fig. 7).

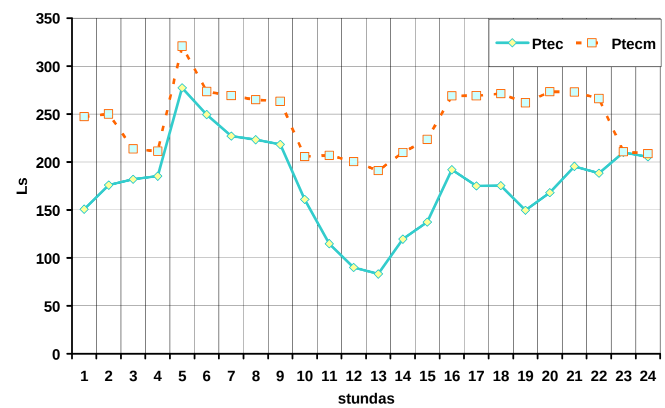

Fig. 7. Profits

V. Conclusion

Planning of operating regimes of CHP plants in new market conditions requires utilization of new mathematical models. Model based on two stage Monte-Carlo optimization method allows achieving quiet good results with moderate requirement of computing resources.

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