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Implementation of heat storage and network water cooler for improvement of energy and economic performance of municipal heating plant with biomass fired cogeneration module

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Abstract

Many fossil fuel fired municipal heating plants have been upgraded to cogeneration systems through installation of biomass fired cogeneration modules. This paper shows the effects of installing an Organic Rankine Cycle (ORC) technology based module in a plant with coal fired water boilers. Current problems related to operation of the integrated system are presented and discussed. Special attention is given to the volatility of the main operational parameters, which impacts the economic performance of the project. With a view to enhancing performance, new equipment such as heat storage and a district heating water cooler are proposed and examined. A mathematical simulation model and optimization algorithm for thermal energy storage capacity sizing were developed using the commercial software EBSILON® Professional. The model was calibrated and validated with real measurement data from the SCADA system of the plant. Results of simulations revealed potential annual financial benefits related to savings of chemical energy of fuels and selling excess electricity on the balancing market. The results of these simulations prove that proposed modifications of the technological system structure could be a good option for increasing investment profitability at the current level of fuel and energy prices.

Keywords: ORC; cogeneration; biomass combustion; thermal energy storage; network water cooler

1. Introduction

Rising energy consumption and anthropogenic emissions of gases linked to climate change are major challenges that Europe has to face. Using locally available renewable energy sources including biomass is regarded as one of the solutions to the problems of energy security and climate protection. Biomass is now the most important source of primary renewable energy in Europe. In 2016 wood, other solid biofuels and renewable wastes took a 49.4% share of the total 211 Mtoe of primary renewable energy production [1]. The most effective technology for utilization of biomass is combined production of heat and power (CHP), also known as cogeneration. The cogeneration industry in Poland is traditionally based on coal. In recent years, the use of biomass in the energy sector has attracted much attention. However, due to issues with biomass fuel transportation and storage, implementation of biomass fired cogeneration has been restricted to mainly small and medium scale plants utilizing locally available feedstock. The main issue in this case is commercial availability of reliable biomass energy conversion technologies.

ORC technology has become an increasingly important solution for small and medium scale biomass-fuelled CHP systems. It is fully commercialized and presents a relatively low technological risk, whereas other technologies, mainly based on gasification, still suffer from difficulties which are hindering wider acceptance on the market. In the case of traditional steam plants there are problems with economic viability of projects at a small scale. Therefore steam plants are rarely used in local energy systems. The total installed capacity of ORC plants in 2016 exceeded 2.7 GW in more than 705 projects where 1754 ORC units have been deployed [2, 3]. The share of biomass fired plants is 11% with 301 MW of the electric power installed in 332 ORC units. The range of the installed electric power of a single plant is 0.2 to 13.0 MW, but most systems are below 1.5 MW. Small plants up to 0.5 MW represent the biggest share of the total number of plants. Most of the plants were built in the period 2004-2016 in Germany, Austria and Italy as the result of effective systems of incentives and financial support for investment projects. However, recent modification of the

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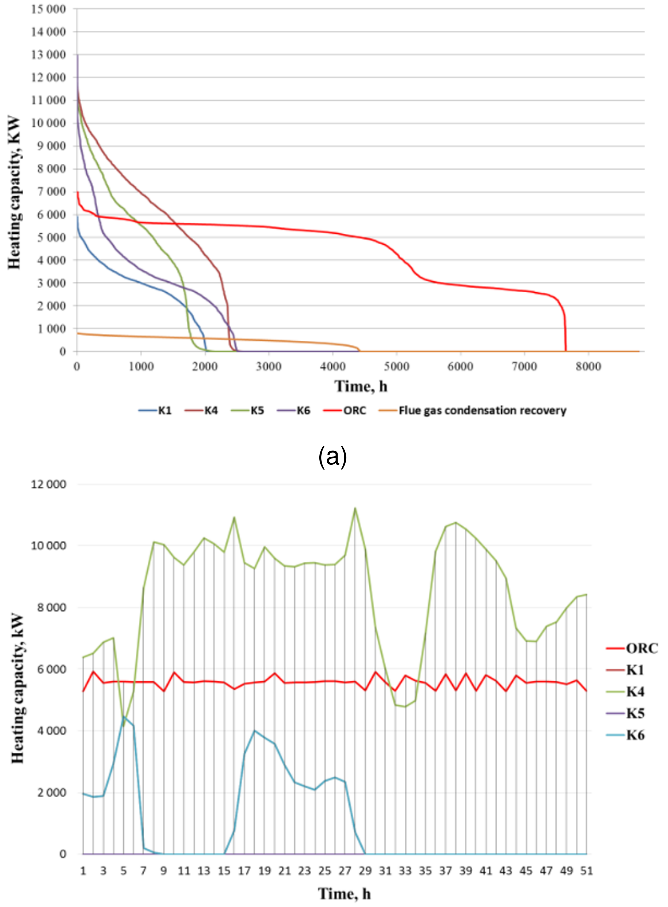


(a)

(b)

Figure 1: Boiler load duration curves (a), sample daily load profile of heat sources (b)

support mechanisms including reduction of feed-in-tariffs as a result of implementation of European Commission Regulation 651/2014 [4] (in Germany) or low market value of certificates of electricity origin (in Poland) have hampered development. It is expected that after 2020 the total installed power will even start falling in Germany from 2020 onwards [5].

In Poland, the number of plants with ORC units is small compared to western Europe. Nowadays, only 8 biomass-fired plant with ORC modules are in operation and 3 plants are under construction. These systems were implemented either in small district heating plants or in the wood industry. No plant has been commissioned since 2015. This is mainly due to unfavorable economic performance resulting from high investment costs, increasing biomass prices due to higher demand, falling energy prices and less attractive financial support mechanisms. Many feasibility studies for biomass combustion systems have concluded that renewable energy projects are heavily dependent on financial support via policy and legal regulatory mechanisms [6, 7, 8, 9, 10]. In each case the economic effects are different depending on the technology, structure, size, design and operating parameters of the energy conversion plant.

Biomass-to-energy projects are typically introduced in existing fossil fuel fired heating plants through either back fitting or modernization projects oriented toward using locally available feedstock and making profits out of electricity generation. This paper presents and discusses a project of this type. The object of research is a municipal heating plant in Krosno (Poland) that has been converted into CHP system through installation of biomass fired unit based on ORC technology. Analysis of performance indicators showed a decrease in the annual average energy efficiency of the coal-fired boiler plant from about 80% to between 71 and 73% (depending on the year) after the CHP unit was commissioned. This is due to the way the boilers are run in the integrated system. Boiler load duration curves indicating part load operation and frequent switching of boilers are presented in Fig. 1a. An example daily load profile is presented in Fig. 1b. It depicts the problem posed by significant volatility of load on an hourly basis.

As mentioned above, the financial support mechanism has a significant impact on the financial profitability of biomass-fired small scale cogeneration. In the Krosno project, a market oriented Quota Obligation mechanism has been applied according to Polish regulations. In this mechanism electricity generated from a renewable energy source is eligible for tradeable certificates of origin. As this system applies to cogeneration as well [9] the investment project in Krosno was supported by two additional streams of income. Immediately prior to the investment decision being made back in 2011, the financial support was at its highest historical level. The project was profitable and the expected discounted pay-back time (DPBT) was 14 years. The results were in line with theoretical studies such as [8]. However, when the investment project reached the commissioning stage, the values of renewable electricity certificates fell rapidly. In addition, the trading system for certificates concerning energy from cogeneration stopped functioning as the relevant legal regulations expired. In addition to the problems with financial support, the price of electricity decreased. When the actual values of profitability indices were corrected taking into account the updated market conditions and reduction in efficiency of the heating boilers, it became apparent that all profitability had evaporated. It has been estimated that in order to become a neutral investment project (NPV = 0) total revenues generated by the project should increase by approximately 15% from the 2017 value. Therefore the management board of the company took the decision to use as much of its electricity as possible on its own premises and sell the excess on the balancing market. Further improvements in economic effectiveness could be gained through installing new equipment such as a heat storage vessel or network water cooler, which could be used to optimize plant operation strategy.

Implementation of thermal energy storage and a network water cooler in the existing system is examined in this work. A mathematical model of the reference system is presented. Based on measurement data, an optimization algorithm for thermal energy storage capacity sizing was developed. The financial effects of system modifications are discussed.

Table 1: Technical data of the plant in Krosno

Specification parameter	Unit of measure	Value
Biomass cogeneration		
Generator power output	kW_e	1400
Captive power consumption	kW_e	62
Indicative turbine isentropic efficiency	%	up to 90
Heating network water temperature (in/out)	°C	60/80
Thermal output to water circuit	kW_{th}	5350
Thermal output from gas condensation system	kW_{th}	800
Thermal output from water cooled moving grate	kW_{th}	120
Total cogeneration heat output	kW_{th}	6270
Nominal temperature HT oil loop (in/out)	°C	310/250
Thermal power input HT loop	kW_{th}	6130
Nominal temperature LT oil loop (in/out)	°C	250/130
Thermal power input LT loop	kW_{th}	585
Overall thermal input	kW_{th}	6715
Indicative biomass consumption (50 % water content)	kg/h	2935
Plant electric efficiency (related to fuel power input)	%	16.4
Cogeneration plant overall efficiency	%	90.5
Heating plant		
Nominal thermal power boiler WR10 (B2,B3,B4)	MW_{th}	10
Nominal thermal power boiler WR4.8 (B1)	MW_{th}	4.8
Nominal coal boiler thermal efficiency	%	83

2. Plant description and reference model

The Krosno plant basically consists of three integrated subsystems: a biomass-fired boiler with thermal oil system, ORC unit and heat only plant equipped with 4 coal fired water boilers. A simplified diagram of the system is depicted in Fig. 2.

During normal operation hot exhaust gases from the biomass combustion chamber (BCC) go through a system of three heat exchangers (OB) where heat is transferred to the thermal oil circuit. The fuel fed into the biomass boiler has a varying composition, a water content varying from 5% to 55% and its lower heating value is between 8–12 MJ/kg. The quality of fuel varies both seasonally and daily. The thermal oil system consists of two loops: high temperature HT (310/250°C) and low temperature LT (250/130°C). The thermal oil transfers heat to the evaporator and the working fluid preheater of the Turboden 14 CHP SPLIT ORC module. The working fluid in the ORC is MDM (Octamethyltrisiloxane). After expansion in the ORC turbine the working fluid goes through the regenerative heat exchanger to the condenser, where heat is transferred to the heating network. The heat rejected by the module is discharged to the return water of the district heating system (DHS). The maximum thermal output is 5350 kW_{th}. The ORC module has a gross electrical power output of 1400 kW_{el}. Furthermore, there are additional heat sources in the plant: an exhaust gas condensation system (GCS), which recovers an additional 800 kW_{th} and a moving grate cooling heat exchanger (MGC) with nominal heating power of around 120 kW_{th}.

The heat only unit houses 4 coal-fired water boilers of the WR type (B1–B4). This is one of the most popular boiler constructions in the Polish heating sector. It is a forced circulation water-tube boiler with a mechanical grate. The nominal heating power of the WR10 boiler is 10 MW_{th} and of the WR4.8 is 4.8 MW_{th}. The design thermal efficiency of each boiler is 83% (ratio of heat output to fuel LHV chemical energy input). The fuel is hard coal of the lower heating value (average weighted): LHV = 23.2 MJ/kg. Main technical data of the plant are given in Table 1.

A mathematical model of the integrated plant was built using the commercial software EBSILON® Professional [11]. The software is a simulator of thermodynamic systems in steady state conditions. It is capable of modeling complex energy conversion systems under design and off-design conditions (i.e. under nominal and partial load). The model consists of a system of individual components. Model equations contain equations describing individual thermodynamic processes as well as mass and energy balances. Each component is additionally described with relevant equations of built-in operational characteristics, which can be modified by the user. The model of the cogeneration system at the Krosno plant is presented in Fig. 3. All existing physical components are represented with relevant blocks of the model. These are: combustion chamber, exhaust gas heat exchangers, thermal oil circuit heat exchangers, working fluid heat exchangers and ORC turbine. The simulation model was calibrated using real measurement data acquired from the SCADA system of the plant.

For good quality model calculations it is necessary to determine the parameters that are output from the model and independent parameters which control the model. Model input and output variables are presented in Table 2. Respective measurement points are shown in Fig. 3. Current load status is determined by the thermal oil heating power delivered to the ORC. The estimated operational characteristics of particular components within the permissible operating range (from technological minimum to maximum load) were implemented. Operating characteristics of the ORC turbine and correlations between mass streams (thermal oil and working fluid) and the load were determined. Efficiency characteristics of coal boilers were also developed. Sample characteristics such as isentropic efficiency of the turbine and energy efficiency of coal boiler are presented in Fig. 4.

The simulation model was validated using measurement data collected over one year of operation. In the first stage of analysis, the simulated parameters were compared with the measured values. Hourly average values of measurements were calculated and implemented in the simulation. This gives 8760 calculation steps of the simulation. Generator power output and consumption of fuels (coal and biomass) were compared in the model validation process. Relative error for the compared parameters was used to assess the quality of the simulation model. The values of relative error $\delta_{x,i}$ of selected parameters were calculated according to the following formula:

$$\delta_{x,i} = \left(\frac{x_i^{model} - x_i^{mesured}}{x_i^{measured}} \right) \quad (1)$$

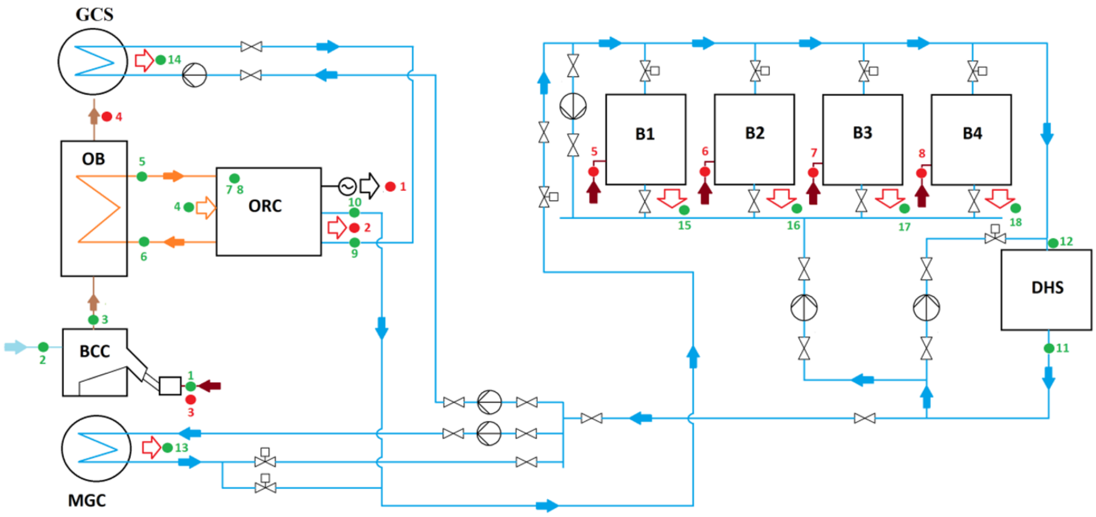


Figure 2: Simplified topology of the Krosno CHP plant with input and output signals

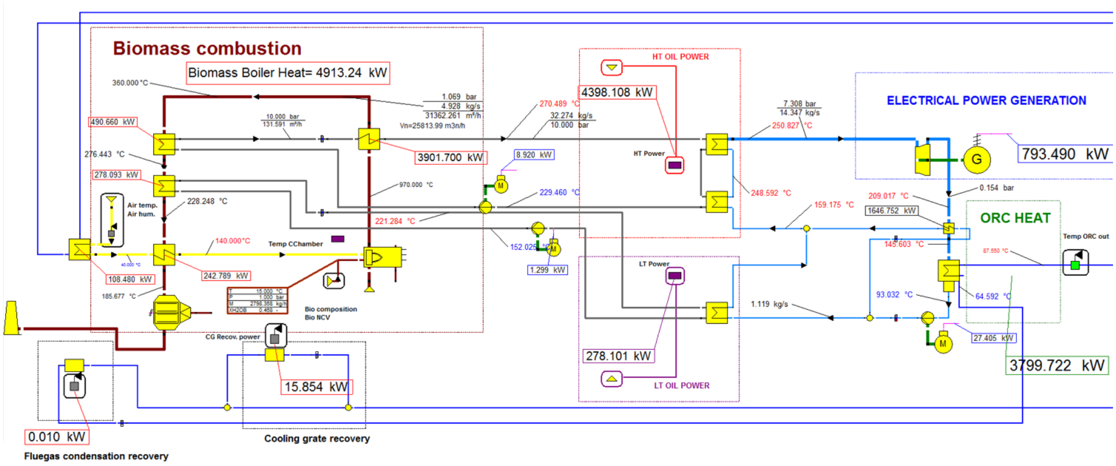
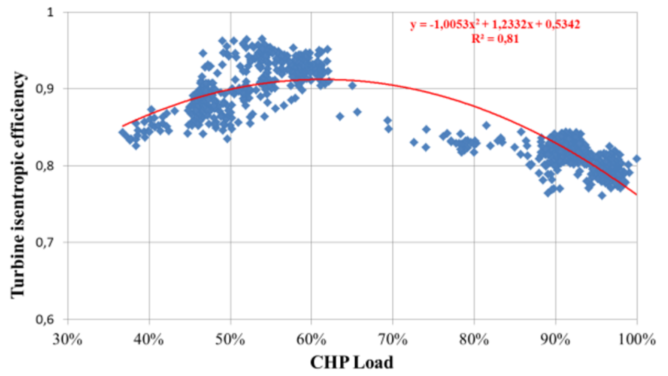


Figure 3: Ebsilon Professional model of biomass fired cogeneration plant with ORC module

Table 2: Input and output signals in mathematical model of Krosno plant

Input signals	p	Output signals
Composition of biomass (c, h, n, o, s, w), mass %	1	Generator power output, kW
Air temperature to biomass combustion, K	2	Heat power of ORC condenser, kW
Temperature of flue gas in combustion chamber, K	3	Biomass consumption, kg/s
Thermal oil power, kW	4	Temperature of flue gas supply to electrostatic precipitator, K
Temperature of thermal oil supply to ORC, K	5	Coal consumption—B1, kg/s
Temperature of thermal oil return from ORC, K	6	Coal consumption—B2, kg/s
Temperature of working fluid in evaporator ORC, K	7	Coal consumption—B3, kg/s
Pressure ORC of working fluid in evaporator, K	8	Coal consumption—B4, kg/s
Temperature of water supply ORC condenser, K		
Temperature of water return from ORC condenser, K		
Temperature of water return from DHS, K		
Temperature of water supply DHS, K		
Heat power of moving grate, kW		
Heat power of gas condensation system, kW		
Heat power of coal boiler—B1, kW		
Heat power of coal boiler—B2, kW		
Heat power of coal boiler—B3, kW		
Heat power of coal boiler—B4, kW		



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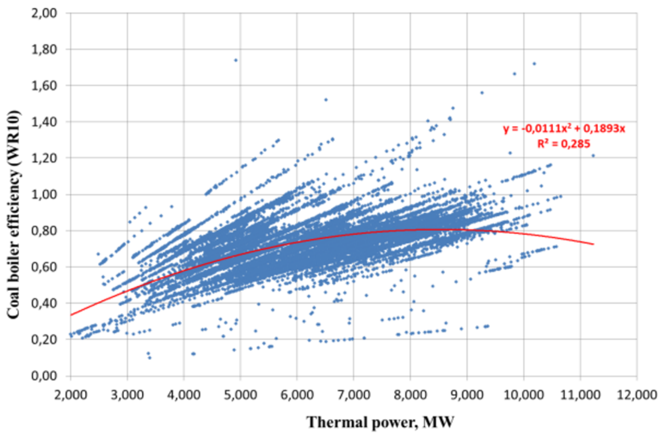

(b)

Figure 4: Approximate isentropic efficiency of the turbine as a function of cogeneration load (a), approximate coal boiler efficiency as a function of thermal power (b)

where: x_i^{model}—simulation model value in the i-th calculation step, $x_i^{measured}$—reference (measured) value in the i-th calculation step.

The values of relative errors of generator power output at part load conditions are presented in Table 3. The values of relative errors obtained from the model validation confirm the correctness and accuracy of the simulation model.

The analysis shows that the difference in generator power between simulated and measured values varies from 0.56 to 7.10% and annual average relative error $\overline{\delta}_{x,i}$ is 3.48%. Fig. 5 depicts relative errors of generator power in sample winter and summer months. The plots show that the model is more accurate in summer when the system is operated at lower loads. This means that the accuracy of the simulation model

Table 3: Example comparison of generator power output in different cogeneration loads

Load CHP, %	Measurement, kW	Model, KW	δx_i, %
100	1338	1377	2.91
90	1263	1295	2.53
70	858	822	4.20
60	722	734	1.67
50	647	643	0.56

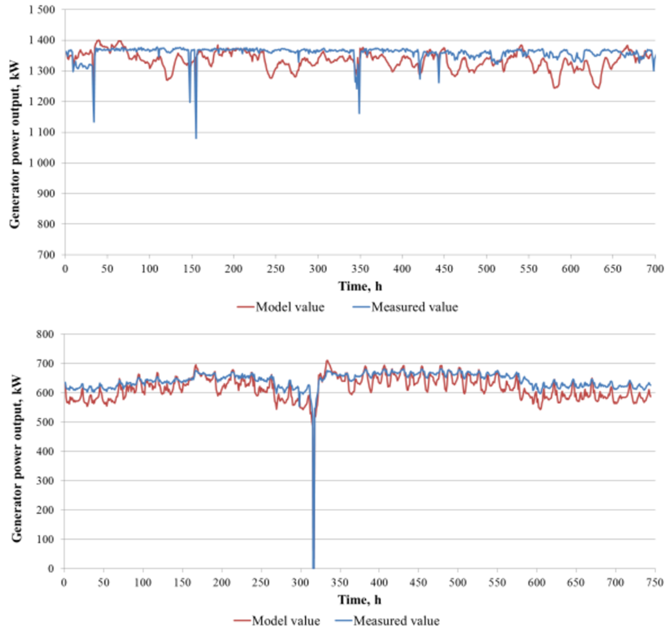

Figure 5: Comparison of electric power in example months (higher—winter month, lower—summer month)

is highest for part load conditions and increases as the load drops. The main reason for this is the thermodynamic state of the ORC working fluid at the outlet of the evaporator. During operation at higher loads (in winter), the MDM is superheated (5–10 K degrees superheating). During summer operation the working fluid is close to the saturation point and the accuracy of the simulation model is better. However, uncertainties of measured data used in the verification process must also be taken into account.

As regards verification of consumption of fuels, the relative errors are higher. Due to the unknown composition of fuels supplied to boilers, the differences between modeled and measured values were compared on a monthly basis. The relative errors in biomass consumption varied from 0.44 to 10.07% (average value $\overline{\delta}_{x,i} = 4.57\%$). Regarding errors in coal consumption, the values oscillated from 0.76 to 48% (average value $\overline{\delta}_{x,i} = 17.5\%$).

In further analysis of effects of plant structure modification, the reference state is the model. In other words the results of modifications are determined within model simulations before and after changes.

3. Thermal energy storage

Thermal energy storage (TES) in the form of a hot water vessel allows excess heat to be stored in periods of low demand and used in periods of high demand. Consequently it leads to higher flexibility, reliability and energy efficiency. The crucial role of heat storage in CHP systems is partial decoupling of electricity generation from heat demand in the DHS. In our case, increased generation of electricity when the electricity price is high increases revenue from selling excess electricity on the balancing market.

Operation of TES and distribution of loads between particular sources of heat were simulated using historical district heating network load data. A relevant control algorithm based on load and electricity price predictions was designed. Operation of TES was divided into two modes:

- Winter operation when CHP runs at full load parallel with coal fired boilers. In this case the objective function is maximization of energy efficiency of coal-fired heating (thus minimization of fuel consumption)
- Summer operation mode when boilers are off and the CHP is the only source of heat for the network. In this case the objective function is maximization of profits from sale of electricity on the balancing market.

It was proposed that operational decisions be taken at a specified time horizon ahead. The length of the time horizon was assumed to be one day, as weather forecasting in this time span is more reliable. In this study each day was divided into hours system operation and all calculations made on an hourly basis. This assumption is justified by thermal inertia of the network and the fact that heating loads are not subject to rapid change. Operational decisions (settings) related to load distribution and TES loading/unloading are generated at the start of each day. It is possible to correct them at each time step. Consequently, it leads to a predictive system control algorithm (MPC—model predictive control).

Assuming that the system control volume of the system contains a cogeneration plant and heat only boilers, the energy balance of the system with TES can be written as follows:

$$\frac{\delta\left(Q_{TES}+Q_D\right)}{\delta\tau}=\dot{Q}_{CHP}+\dot{Q}_{HP}-\dot{Q}_{DHS}-\dot{Q}_L \tag{2}$$

where: $\dot{Q}_{DHS}$—heat flux into the district heating network, $\dot{Q}_{CHP}$—heating power of cogeneration, $\dot{Q}_{HP}$—heating power of coal fired heating plant, $\dot{Q}_L$—heat loss from TES, Q_{TES}—heat accumulated in TES (load/reload), Q_D—heat accumulated in pipelines, τ—time.

It was also assumed that parameters of water do not change in the system compared to the current reference values. In this case storage of heat in internal pipelines of the plant Q_D can be neglected. To simplify the analysis, heat losses from TES Q_L were assumed to be negligible due to the relatively short period of storage and quality of the insulation). After integration of eq. (2) the change of state of charge of TES can be calculated:

$$\begin{aligned}\Delta Q_{TES}\Big|_0^{24}&=\int_{\tau=0}^{\tau=24}\dot{Q}_{TES}\,\delta\tau\\&=\int_{\tau=0}^{\tau=24}\left(\dot{Q}_{CHP}+\dot{Q}_{HP}-\dot{Q}_{DHS}\right)\delta\tau\end{aligned} \tag{3}$$

It should be noted that the current value of $\dot{Q}_{TES}$ can be either positive (loading) or negative (unloading).

To minimize heat losses within the control algorithm it was assumed that initial and final states of charge are the same:

$$\Delta Q_{TES}\Big|_0^{24}=0 \tag{4}$$

The constraint of TES charging and discharging processes is the charging/discharging rate which results from the water flow rate in the pipelines:

$$\dot{Q}_{TES,min}\leq\dot{Q}_{TES}\leq\dot{Q}_{TES,max} \tag{5}$$

$$w_{min}\leq w\leq w_{max} \tag{6}$$

The minimum flow rate in the pipelines is dependent on the characteristics of the pipes, pumping system and valves. The maximum speed is the assumed design speed for the assumed pipeline diameter. The instantaneous speed for a hot water pipeline can be written as follows:

$$w=\frac{\dot{m}}{A\rho_h}=\frac{\dot{Q}_{TES}}{h_{w,in}-h_{w,out}}\cdot\frac{4}{\pi\rho_h d^2} \tag{7}$$

where: A—cross-sectional area of the pipeline, ρ_h—density of hot water, $\dot{m}$—mass stream of water (for the incompressible fluid, the inlet stream is equal to the outlet), $h_{w,in}$—water enthalpy supply to TES, $h_{w,out}$—water enthalpy return from TES, d—diameter of the pipeline.

3.1. TES control algorithm in winter

The winter mode of operation is used in periods when coal boilers are operated:

$$Q_{HP,j}>0 \tag{8}$$

where: $Q_{HP,j}$—heat generated in coal boilers in the j-th prediction horizon (day) and the boilers are started when the CHP and TES are unable to meet heat demand in a given horizon of prediction, thus the following condition is met:

$$\int_{\tau=0}^{\tau=24}\left(\dot{Q}_{CHP}+\dot{Q}_{TES}-\dot{Q}_{DHS}\right)\delta\tau<0 \tag{9}$$

The first step in control algorithm control is assessment of the suitability of TES operation in the given horizon of prediction. Instantaneous thermal power of TES in the winter mode (loading / unloading) is calculated using the following equation:

$$\dot{Q}_{TES,ij}=\int_{B=1}^{B=n}\dot{Q}_{B,ij}-\dot{Q}_{HP,avr,j} \tag{10}$$

where: n—number of working coal boilers, $\dot{Q}_{TES,ij}$—TES power (loading/reloading) heat flux within the i-th hour of j-th time horizon, $\dot{Q}_{B,ij}$—HP power demand of the i-th hour, j-th time horizon, $\dot{Q}_{HP,avr,j}$—average heating plant (boilers only) power demand within the j-th time horizon.

Coal fired boilers can work only in the range of permissible loads:

$$\dot{Q}_{B,min}\leq\dot{Q}_{B,ij}\leq\dot{Q}_{B,max} \tag{11}$$

Based on the given operating conditions threshold conditions were developed for running particular components of

Table 4: Working conditions of coal boilers with thermal energy storage

Daily average HP power, MW	Max. HP power, MW	TES	B1	B2	B3
≤6	≤6	N	Y	N	N
≤6	>6	Y	Y	N	N
>6, ≤12	≤12	N	N	Y	N
>6, ≤12	>12	Y	N	Y	N
>12, ≤18	≤18	N	Y	Y	N
>12, ≤18	>18	Y	Y	Y	N
>18, ≤24	≤24	N	N	Y	Y
>18, ≤24	>24	Y	N	Y	Y

the system in the heating season. Table 4 shows when operation of TES and particular boilers is considered in the control algorithm.

As the coal boilers are of the same type, it was assumed according to technical documentation that dimensionless efficiency characteristics of all the coal boilers are the same (see Fig. 4b).

The operation of TES in winter mode avoids use of an additional boiler (peak boiler) means a bigger boiler (B2 or B3) can be replaced with a smaller one (B1). The effects of TES operation were determined using historical data from the SCADA system. Fig. 6 depicts the effects of TES operation in sample days. On the left figure (a) TES allows the large boiler to be replaced with the small one. The right hand side figure (b) shows avoidance of switching on the peak boiler. Consequently, the presented TES control algorithm leads to improvement of energy efficiency of heat generation, reduction of primary energy consumption and lower emissions.

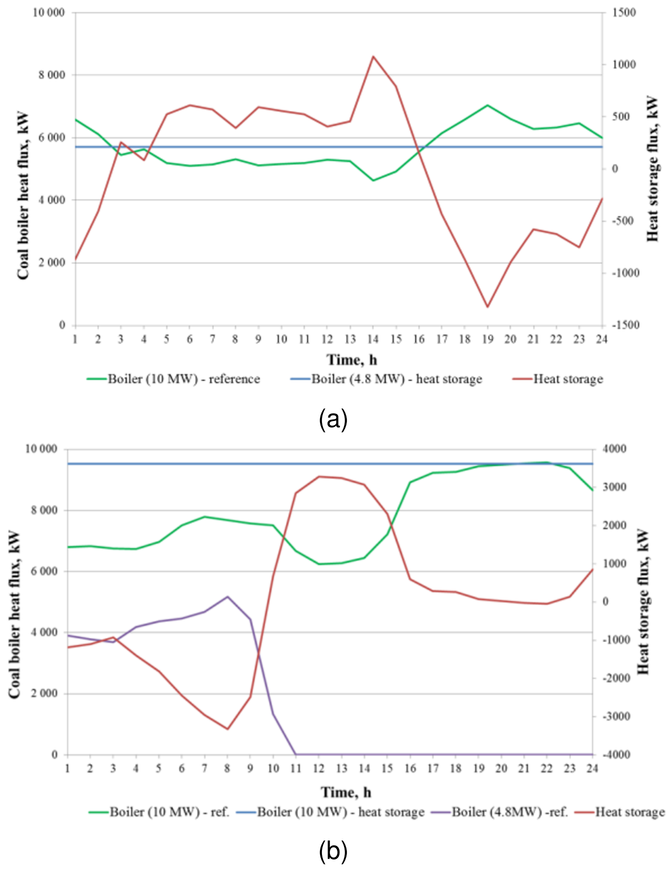

Figure 6: Effects of the winter TES work in the example days—operation with a smaller coal boiler (a), effects of the winter TES work in the example days—avoidance switching on of the peak boiler (b)

3.2. TES control algorithm in summer

The concept for TES operation in the summer season assumes that the CHP runs on partial load as the only heat source for the heating network. It was assumed that the summer mode algorithm is taken into account when the following inequality is met:

$$\dot{\varphi}_j^{ref} > 0.9 \tag{12}$$

where: $\dot{\varphi}_j^{ref}$—average reference CHP load within the j-th time horizon considered.

The CHP load is related to the thermal oil power supplied to the ORC module: (boilers only) power demand in the j-th time horizon:

$$\dot{\varphi} > \frac{\dot{Q}_{oil}}{\dot{Q}_{oil,max}} \tag{13}$$

where: $\dot{Q}_{oil}$—instantaneous thermal oil power, $\dot{Q}_{oil,max}$—maximum thermal oil power.

In the summer mode TES enables a partial shift of electricity production to hours of maximum prices on the balancing market. However, there is a limitation on the work of the TES resulting from the total heat demand within the horizon of prediction. Generation of electricity for the balancing market does not lead to an increase in the amount of heat generated within a day. The condition of a constant amount of heat generated results in a significant reduction in the potential production of electricity. In order to eliminate this, the possibility of installing a network water cooler (NWC) was taken into account. The NWC gives the option of totally decoupling electricity generation from heat demand, and therefore additional increase of generator power output.

In order to optimize the operating parameters of the system, the operational characteristics of the biomass fired cogeneration unit were elaborated. Based on the reference model, the characteristics of the generated electric power, heating power of the ORC condenser and the fuel power consumed as a function of the load were created. An example characteristic (electric power as a function of CHP load) is presented in Fig. 7. To determine the characteristics, only the points of operation were adopted when the CHP system was the only source of heat for the heating network.

Three alternative variants of control algorithm for the summer work mode were proposed. In simplified method A, the increase in system load and consequently the increase in electrical power output is proportional to the instantaneous increase in the energy price during the day. In alternative method B, the CHP system load settings in the following hours are optimized to maximize profits from sales of electricity. This option requires an optimizer to be integrated with the control software. The third variant takes into account the

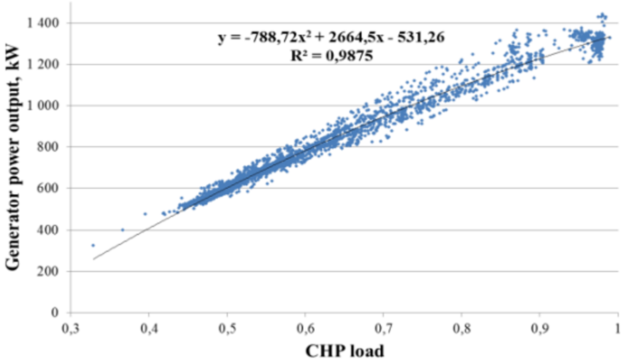

Figure 7: Approximate operating characteristics of generator power output as a function of cogeneration load

operation of NWC. The load increase possible in this case leads to the greatest financial profits.

Control of thermal energy storage—method A

The maximum possible increase in load due to operation with TES was determined as follows:

$$\Delta\varphi_{max}^{TES} = max\left(\left|\varphi_{spec} - \overline{\varphi}_j^{\,ref}\right|\right) \tag{14}$$

where: φ_{spec}—specific load which is either $\varphi_{max} = 1$ or $\varphi_{min} = 0.3$.

Deviation of the load from the average value is then determined proportionally to the deviations of the energy price from the average daily value:

$$\frac{\Delta\varphi_{ij}}{\Delta\varphi_{max}^{TES}} = \frac{\Delta c_{el,ij}}{\Delta c_{el,max,j}} \tag{15}$$

where: $\Delta\varphi_{ij}$—the difference between the instantaneous and the average load value, $\Delta\varphi_{max}^{TES}$—the difference between the maximum and the average load value, $\Delta c_{el,ij}$—the difference between the instantaneous and the average electricity price, $\Delta c_{el,max,j}$—the difference between the the maximum and the average electricity price.

The increase in electricity is related to the load through characteristics of the system (see Fig. 7):

$$\Delta N_{el,ij} = f\left(\varphi_{ij}\right) \tag{16}$$

Control of thermal energy storage—method B

As the average load of the ORC unit remains unchanged, the changes in average efficiency and costs of the system are negligible. Therefore optimal distribution of load is achieved according to the financial income. The maximum income from the sale of electricity is determined:

$$P_{el} = \int_{\tau=0}^{\tau=24} \left(\Delta N_{el,ij} \cdot c_{el,ij}\right) \delta\tau \to max \tag{17}$$

Constraints result from the facts that the cogeneration system can work only within the range of permissible loads and

Table 5: Summer mode indicators for an example day

Parameter	REF	TES "A"	TES "B"	NWC
Heat produce from CHP, GJ	236.6	236.6	236.6	330
Waste heat, GJ	0	0	0	93.4
Electricity produce, MWh	14.1	13.6	12.6	22
Biomass consumption, GJ	370	370	370	539
Costs of biomass consumption, PLN	6994	6994	6994	10187
Electricity sale incomes, PLN	6701.9	9226.5	10412.5	12928
Daily profit, PLN	-292	2524	3711	2741

the daily production of remain unchanged in relation to the reference value:

$$\Delta\varphi_{max}^{TES} = max\left(\left|\varphi_{spec} - \overline{\varphi}_j^{\,ref}\right|\right) \tag{18}$$

$$Q_{ORC}^{TES} = Q_{ORC}^{REF} \tag{19}$$

where: $\Delta N_{el,ij}{}^{NWC}$—increase in electricity generation of the i-th hour, j-th time horizon considered, $c_{p,ij}$—electricity price of the i-th hour, j-th time horizon considered.

Network water cooler

Optimal load increase and acceptable working area of NWC are determined by the maximum financial profits of the system:

$$\frac{3.6 \cdot \Delta N_{el,ij}{}^{NWC} \cdot c_{p,ij}}{\Delta E_{bio,ij}{}^{NCW} \cdot c_{bio,ij}} \to max \tag{20}$$

where: $c_{p,ij}$—electricity price of the i-th hour, j-th time horizon considered, $c_{bio,ij}$—biomass price of the i-th hour, j-th time horizon considered.

Fig. 8 depicts summer mode operation of the system with TES and NWC in a sample day in all 3 variants of control algorithm. System performance indicators are presented in Table 5. The analysis revealed that control method A gives slightly worse results than the solution based on the optimization tools (method B). However, optimization calculations are not required and the algorithm is more easily implemented. Daily profit in method A was 2233 PLN/day and in method B it was 3419 PLN/day. The biggest incomes for the sale of electricity were obtained in the variant with a network water cooler. However, due to the increased fuel consumption, daily profit – 2740.9 PLN – was lower than in the system with TES only and control method B.

4. Simulation results

Simulations were performed for each day of the year period. The hourly amount of heat storage in TES and achieved thermal power of the heat storage during a year are shown in Fig. 9 and Fig. 10. The results of the simulation were used to determine the maximum volume of the TES. As a consequence, the highest efficiency of heat generation in the coal boilers was achieved. The maximum volume of the TES includes the additional volume occupied by the thermocline

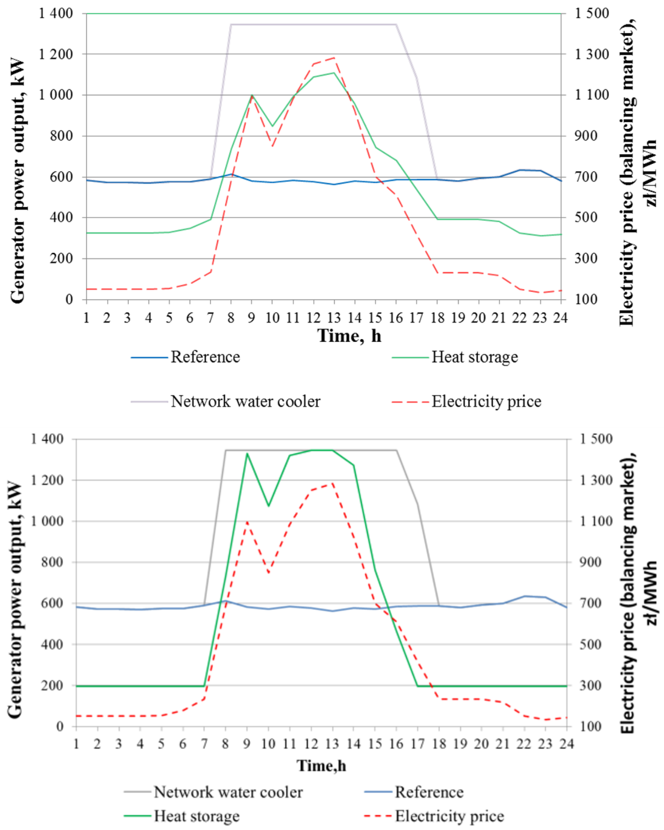

Figure 8: Daily TES and NWC working operation (higher—method A, lower method—B)

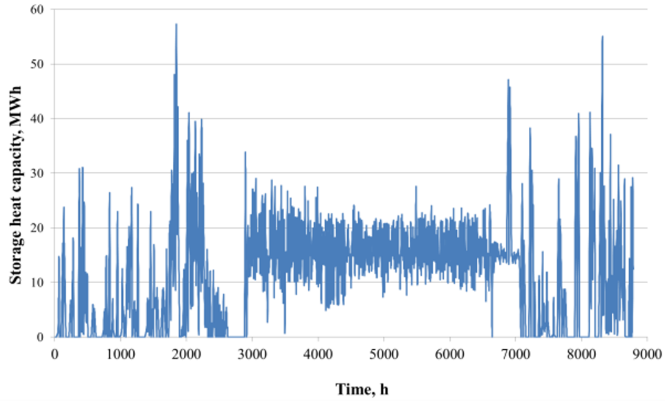

Figure 9: The hourly amount of heat accumulation in TES

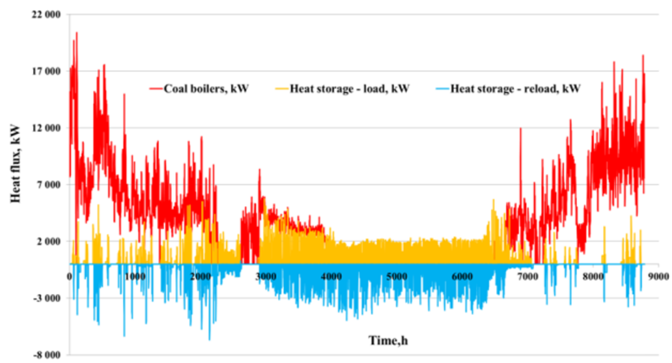

Figure 10: Heat storage power during the year

(10% of the TES working volume). The maximum working volume of TES was calculated from the following formula:

$$V_{max} = \left(\frac{Q_{TES,max}}{c_{p,w} \cdot \Delta\overline{T}_w \cdot \rho_w} \right) \tag{21}$$

where: $Q_{TES,max}$—maximum storage heat capacity during the year, $c_{p,w}$—specific heat of hot water, $\overline{T}_w$—average increase in the temperature of water in the heating network, ρ_w—hot water density.
An analysis of selection of the optimal TES volume was carried out. The problem was solved by maximizing the objective function—Net Present Value (NPV). In the simulation, the volume of the TES was reduced and the largest value of NPV sought. The results are shown in Fig. 11. Financial analysis showed that the DPBT for the optimal volume is around 11 years (Fig. 12). The possibility of obtaining subsidies was taken into account. Subsidies were assumed at 30% of the purchase cost of the heat storage unit. The cogeneration plant in Białystok (Poland) received similar financial support for an investment project dedicated to installation of TES [12]. Taking into account the subsidy, the payback time from 4 years (optimal volume) to around 11 years (maximum volume). The investment of the maximum volume of the TES without subsidies would be unprofitable.
The energy indicators and annual savings resulting from the proposed modernizations are shown in Table 6. The results were presented in four scenarios:

- Scenario I—Network water cooler,
- Scenario II—Maximum TES volume (2000 m^3) and TES algorithm using method B,
- Scenario III—Optimum TES volume (800 m^3) and TES algorithm using method B,
- Scenario IV—Optimum TES + NWC TES and algorithm using method B.

The results of this study show that implementation of TES and NWC could be a good option for the Krosno plant, both from the economic and energy point of view. Running heat storage during the heating period significantly increased the efficiency of the heating plant (Fig. 13). Average heating plant efficiency for maximum TES volume was 0.771 and optimum was 0.756. The work mode of the system in the summer saved an additional PLN 60,000. A comparison of electricity production during the operation of thermal energy storage and the network water cooler is presented in Fig. 14.

5. Conclusions

The paper presents the concept of implementation of thermal energy storage and a network water cooler to a munic-

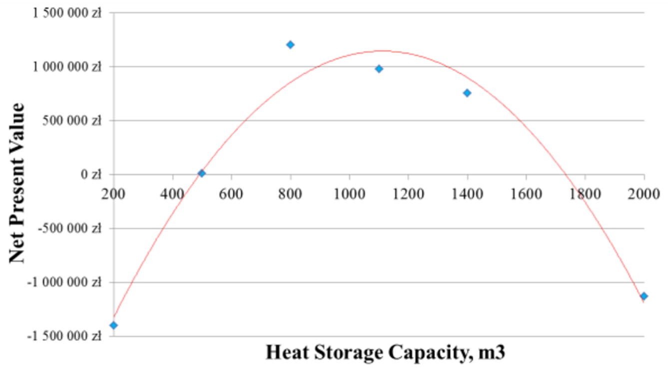

Figure 11: Results of optimizing the TES volume selection

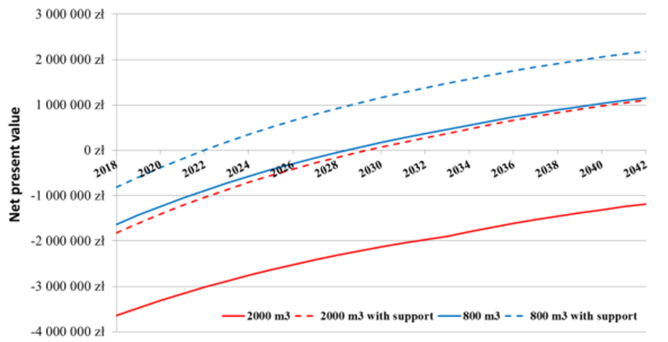

Figure 12: Discount payback time of TES

ipal heating plant integrated with a biomass-fired cogeneration module. Modernization was aimed at optimizing the plant operation strategy and increasing investment profitability in the face of problems relating to the current level of fuel and energy prices. The mathematical model of the Krosno plant was elaborated, calibrated and validated with real measurement data from the SCADA system. The results of parameter verification from the model showed high accuracy. The differences between the measured electrical and simulation electrical values resulted from the variable working state of the ORC. If the working medium was in the satu-

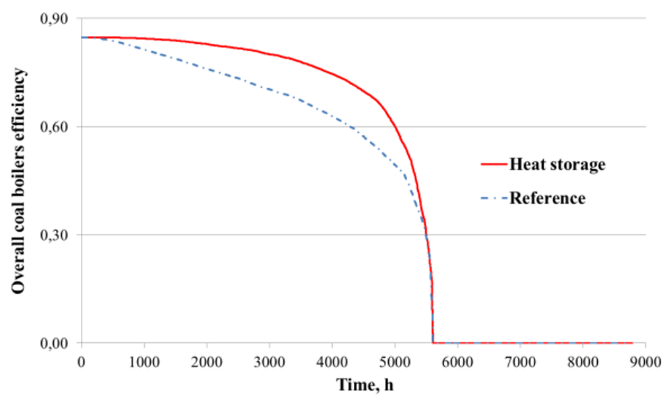

Figure 13: The coal boiler's efficiency curve (maximum TES volume)

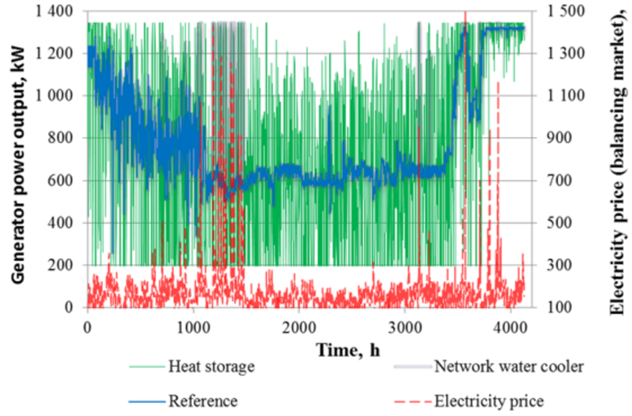

Figure 14: Generation of electricity in the summer

rated state, the relative error values were smaller. Based on the reference data, a thermal energy storage algorithm was developed and presented. The algorithm was divided into 2 work modes: winter mode – maximizing the efficiency of heat generation in a coal-fired heating plant and summer mode – maximizing profits from sale of electricity on the balancing market.

The results presented in this paper were obtained using commercial software that created reference models as well. The simulation results of the reference system and after modernization are presented. The analysis showed that the installation of a TES increases the average efficiency of heat generation in a coal-fired boiler by as much as 8.8%. The summer work mode also saves tens of thousands of PLN a year. Optimization of the selection of the storage capacity was carried out. The function of the optimal volume TES target was the NPV value. Financial analysis showed that the DPT time for the optimal TES volume is 11 years – 4 years if a subsidy is received. The results of this simulation confirm that the proposed solutions could improve the energy and economic performance of the Krosno plant.

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Table 6: Results of simulation analysis of the system with TES and NWC

Parameter	Unit	Reference	SI	SII	SIII	SIV
Annual heat produce from CHP	GJ	147 047	147 965	147 047	147 047	147 495
Annual heat produce from Heating plant	GJ	118 271	118 271	118 271	118 271	118 271
Annual waste heat	GJ	0	919	0	0	186
Annual overall heat produce	GJ	265 318	265 318	265 318	265 318	265 318
Annual electricity produce	MWh	9 281	9 354	9 146	9 146	9 161
Annual biomass consumption	tons	24 454	24 610	24 454	24 454	24 494
Annual coal consumption	tons	7 303	7 303	6 483	6 575	6 575
Average energy CHP efficiency (power generation)	-	0.155	0.15485	0.152	0.152	0.152
Average Energy CHP efficiency (overall)	-	0.836	0.831	0.833	0.833	0.832
PES (cogeneration)	-	0.195	0.192	0.191	0.191	0.190
Average heating plant efficiency	-	0.683	0.683	0.771	0.756	0.756
Average plant effciency	-	0.793	0.790	0.833	0.828	0.827
Annual electricity sale incomes	mln PLN/y	1.448	1.502	1.508	1.508	1.516
Annual sale of certificates of electricity origin incomes	mln PLN/y	0.464	0.468	0.457	0.457	0.458
Annual costs of biomass consumption	mln PLN/y	4.081	4.110	4.081	4.081	4.088
Annual costs of coal consumption	mln PLN/y	2.337	2.337	2.075	2.104	2.104
Annual cost of fuel consumption	mln PLN/y	6.418	6.447	6.156	6.185	6.192
Annual financial benefits	PLN/y	-	28 607	316 240	286 892	288 527

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