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Energy and economic effectiveness of gas-steam combined heat and power plants fired with natural gas
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Dual-fuel gas and coal-fired systems — concepts of new applications

The energy policy related to the reduction in CO₂ emissions creates interest in new concepts of multifuel systems. The paper presents an analysis of gas and coal fired power plants in which the flue gas waste heat of the gas-fired system is used to feed the CO₂ separation system of a plant fired with coal. The analysed structures are assessed in terms of savings in the fuel chemical energy and CO₂ avoided emissions.

1 Introduction

The energy policy of many countries assumes that fossil fuels, and coal in particular, will remain the main source of energy needed for electricity generation. This results from the high reserves of coal and their geographical distribution, which guarantees energy security [1]. The main downside of energy obtained from coal are the huge carbon dioxide (CO₂) emissions released into the atmosphere during its generation. This particular feature stimulates the search for new technologies in the use of coal. The most promising method of a significant reduction in coal-fired power plant CO₂ emissions seems to be the process of capture and storage (CCS technologies) [2–5]. Carbon dioxide capture involves additional energy expenditures which lower the electricity generation efficiency and the economic effectiveness. Moreover, the aim of the implemented market mechanisms concerning emissions trading is to enforce energy technologies that will limit the amount of CO₂ released into the atmosphere. These mechanisms, however, are burdened with a higher investment risk.

An interesting concept in the development of energy technologies is the use of diversified fuels in installations which are now being overhauled or designed.

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The use of such concepts is justified by the smaller risk related to changes in fuel prices, the high effectiveness of energy, the possibility of restoring power capacity of older units and the reduction in emissions in the case of fuels containing less coal per a unit of energy. So far, interest has been focused mainly on such multifuel solutions, e.g. combined cycles [6,7], that – if applied – make it possible to obtain an extra energy effect. This group comprises dual-fuel gas-steam cycles (gas, liquid fuel – solid fuel (coal, biomass)) and it generally includes the following:

- combined serial systems (with flue gas discharge into the boiler), Fig. 1a;
- parallel systems (installations coupled by means of a water-steam cycle), Fig. 1b;
- systems combining the characteristics of the two installations mentioned above.

Figure 1. A dual-fuel system with a front gas turbine a), and combined dual-fuel parallel system b): GT – gas turbine installation, SB – steam boiler, ST – steam turbine, RS – regenerative system, PS - flue gas purification system, STI – steam turbine installation, SG – steam generation, SH – steam heater, LPR, HPR – low and high pressure regenerative systems, $N_{GT}$, $N_{ST}$ – power capacity of the gas and steam turbine installations.

Efforts to reduce CO$_2$ emissions have resulted in new possibilities of application of multifuel systems. An example of this solution is the gas and coal fired system, where coal is the main fuel in the condensing power plant while the gas-fired power plant generates electricity and the heat for the CO$_2$ desorption process in the capture installation. The fuel for the gas installation is the natural gas,
which features a smaller content of coal per a unit of chemical energy compared to hard coal. The most significant features of this system are: no interference with the cycle of the steam power plant, which guarantees the achievement of high values of efficiency, also in the case of operation with no CO\(_2\) separation, and the need to provide big amounts of gas fuel, which may be difficult at the coal-fired power plant location.

Coal and gas fired power plants operating together feature a different efficiency compared to plants operating autonomously. Therefore, the assessment of the chemical energy consumption in comparison to facilities working separately is a vital issue from the point of view of the usefulness of such solutions for the economy. Assessing such solutions, it is also essential to determine the avoided emissions of CO\(_2\). The results of these types of assessment may be important for the development of the power engineering strategy at the level of both national economy and the power sector plants.

2 The idea and parameters of the gas-coal systems under analysis

The idea of the considered concept of gas-coal systems is presented in Fig. 2. The concept assumes that the coal-fired power plant is a high efficient system that features ultra-supercritical steam parameters with a cycle which is typical of the state-of-the-art power plants currently built. Generally, the cycle of such a plant does not differ from a plant without CO\(_2\) capture. The only differences are in the path of the flue gases from the boiler into the surroundings. The coal-fired power plant flue gases flow into the CO\(_2\) separation system, where the gas is separated. The main source of energy in the separation system is the heat (Q) for the desorption process. In each case, the gas system is composed of a gas turbine and a system designed to use the waste heat from the turbine flue gases. A part of this heat may be used to feed the CO\(_2\) separation system and another part – to generate extra electricity (N\(_{\text{el,co}}\)). In the analysis it is assumed that CO\(_2\) is not removed from the gas system flue gases due to lower emissions from the gas fuel.

The modelling of the gas, steam and gas-steam cycles is performed with the Gate Cycle program. The program makes it possible to determine the parameters of the gas and steam cycles. The parameters of the agents are determined based on the real gas model. The cycle parameters are determined for the nominal working point only and they ignore the impact of the change in the ambient temperature on the power plant operation. Despite this, it should be noted that
most gas turbine characteristics are a linear function of the ambient temperature and for this reason the average value may be assumed for the calculations.

2.1 The coal-fired steam power plant

The coal-fired steam power plant under consideration features supercritical steam parameters (live steam $t = 653 \, ^\circ C$, $p = 30 \, MPa$, reheated steam $t = 672 \, ^\circ C$, $p = 6 \, MPa$). In this power plant cycle identical solutions and facilities are applied as those used in new coal-fired power plants (e.g., the steam attemperator as the final regenerative exchanger). The plant basic parameters are as follows:

- gross efficiency of electricity generation: $\eta_{elc} = 49.47\%$,
- gross electric power: $N_{elc} = 900 \, MW$,
- own needs: 10%.

The parameters of the power plant under analysis are dedicated for highly efficient and zero-emission power units and they do not reflect the present state of the art in the condensing power plant technologies. This is due to the paper is created within research programme “Development of technologies for highly efficient zero-emission coal-fired power units integrated with CO$_2$ capture from flue gases”. The assumptions of this project are adopted in this paper.

2.2 The CO$_2$ capture system

One of the most often suggested methods for the systems of coal-fired condensing power plants is absorptive CO$_2$ separation. Absorptive methods allow CO$_2$ capture under low pressure (there is no need to compress flue gases), and it is
possible to obtain a gas of high purity – 99%. They do not require a high CO\textsubscript{2} concentration in flue gases. The technology is well-known and it is successfully used in the chemical industry [8]. There are some drawbacks, of course, such as the need for sorbent regeneration, which requires high energy expenditures, and the need for deep gas purification (sulfur and nitrogen compounds, as well as dust, can result in sorbent degradation). Absorption is a phenomenon during which gas is taken in by a liquid in which it dissolves to a certain degree. Carbon dioxide separation is based here on one or several reversible reactions between CO\textsubscript{2} and other substances. The sorbing agents are aqueous solutions of compounds such as: amines – for example monoethanolamine (MEA) and diethanolamine (DEA) – ammonia, potassium or sodium hydroxide, and others which are still being examined and tested. The reactions that take place between the compounds and carbon dioxide are most often reversed with the use of external heat, and the product is a mixture of carbon dioxide and steam plus regenerated sorbent. The absorption process carried out in the absorber-stripper system is presented in Fig. 3 [9,10], where the subsequent stages of the chilled ammonia process are taken into account. It should be emphasised that only the heat needed for the sorbent regeneration is exclusively taken into consideration in the calculations as the amount of energy needed for the process of CO\textsubscript{2} separation. The demand for energy related to gas compression and to the needs of the flue gas attemperator is accounted for by increasing the own needs index.

The gas with CO\textsubscript{2} to be separated is fed into the absorber which contains a sorbent. CO\textsubscript{2} is separated from flue gases as a result of the reaction between the gases and the sorbent. After the absorption process is completed, the solution is heated in a heat exchanger and then brought to the top of the stripping column, where the gas undergoes the desorption process through heat feeding. After desorption, the sorbent flows into the exchanger and further to the absorber, and the separated CO\textsubscript{2} is directed to the compression process and transport [8]. For the variants under analysis, the sorbent before the stripping column is heated to the temperature from 115 °C to 155 °C.

The CO\textsubscript{2} separation by means of the absorption method with the use of ammonia is modelled with the Aspen Plus software code (the ELECNRTL model is selected for the calculations [4,5]). Carbon dioxide separation with the use of chilled ammonia (following the chilled ammonia process) is considered [10,11]. An analysis of CO\textsubscript{2} separation with the use of this method gives an amount of heat necessary to carry out the CO\textsubscript{2} separation process. The value is 2.02 MJ/kg of separated CO\textsubscript{2} [9]. However, studies are available where this value is lower, e.g. [12,13].
Figure 3. A block diagram of the installation for the CO\textsubscript{2} capture from flue gases.

2.3 The gas-fired part

A gas turbine model composed of separate components is used. In the modelling process, the air mass flow at the gas turbine inlet is selected in order to match the size of the steam and gas cycles to the demand for heat needed for desorption. For this reason, the gas turbine power capacity does not have to correspond to the power capacity of gas turbines which are commercially available at present. It should also be noted that the biggest state-of-the-art gas turbines feature a power capacity that allows the construction of such systems.

The gas turbine model is defined considering the parameters featured by the most advanced gas turbines. In particular, this concerns the pressure ratio of 20 and the turbine inlet temperature (TIT) of 1265 °C. Within the model, the cooling of the expander components is modelled in a simplified way. The obtained efficiency value is comparable to that of current-generation gas turbines, especially while considering gas turbines fed with air with a temperature lower than nominal.

Three variants of a gas turbine plant are considered. One of them (variant A) is composed of a gas turbine and a water heater. The next variant is composed of
a simple gas turbine, a single pressure heat recovery steam generator and a back-pressure steam turbine (variant B) and the last – of a simple gas turbine with the air bottoming cycle (variant C). In variant B, the steam from the backpressure turbine outlet and the hot water from last heat exchanger in the heat recovery steam generator (HRSG) is the source of heat for the desorption process in the system of CO$_2$ capture of the coal-fired plant. The thermodynamic analyses are conducted assuming that the heat needed for desorption in systems A, B and C is supplied in a form no other than hot water. All exchangers are modelled assuming minimal temperature differences between the agents of 5 °C. Additionally, it is assumed that the water heat capacity flux is equal to the sorbent heat capacity flux, which guarantees that the difference between the sorbent and the heating water temperatures is constant.

The parameters of the gas-fired part of the system with a water boiler are as follows:

- net efficiency of electricity generation: $\eta_{el,g,A} = 40.0\%$,
- net generated power: $N_{el,g,A} = 268$ MW,
- flue gas temperature at the water boiler outlet: $t = 125$ °C.

An essential feature of this gas system is that the use of waste heat from the gas turbine flue gases does not entail any significant changes in the electricity generation efficiency values, which affects the ecological indices (e.g. CO$_2$ avoided emissions).

The parameters of the gas-fired part of the system with a backpressure turbine are as follows:

- net efficiency of electricity generation: $\eta_{el,g,B} = 47.47\%$,
- net generated power: $N_{el,g,B} = 375$ MW,
- flue gas temperature at the steam boiler outlet: $t = 125$ °C.

The gas-steam system under analysis features a relatively low electricity generation efficiency compared to current-generation systems of gas-steam electrical power plants, but this efficiency basically depends on the parameters of the heat supplied to the CO$_2$ capture installation.

The electricity generation efficiency can further be raised by using a multi-pressure waste heat boiler. Although this will increase investment expenditures significantly, a system like this, after a detailed analysis and optimisation, may be more effective economically. Multipressure boiler systems are not considered in this paper due to their more complex structure and the need to carry out a multivariant optimisation. Another step which could improve the efficiency
of the system is to use a steam cycle with a condensing turbine. However, this solution results in a decrease in the total efficiency and a rise in the gas-to-coal cycle power ratio, which may have an adverse effect on avoided emissions and on the economic effectiveness.

An interesting example of a gas turbine development aiming at an improvement in the electricity generation efficiency is the use of a gas-air cycle.

The features that make gas-air cycles interesting are as follows [14–17]:

- the chance to raise the efficiency of power installations with gas turbines,
- the potential to meet the peak demand for power,
- mobility,
- no demand for water,
- no toxic substances in the cycle.

Figure 4 presents the diagram of the simple gas turbine system coupled to an air turbine system through a heat exchanger HTHE treated as an air waste heat boiler with heat exchange efficiency of 96%. The gas part exhaust gases and the air from the air turbine contain enough heat to use in the CO₂ separation system.

The following internal efficiencies of the machines are assumed:

- internal efficiency of the compressor $C_2 - \eta_{C2} = 88\%$,
- internal efficiency of the air turbine $E_2 - \eta_{E2} = 90\%$,
- efficiency of the electricity generator $G_2 - \eta_{G2} = 98\%$.

In the simple gas-air cycle a compressor with no inter-stage cooling, a heat exchanger coupling the gas and air cycles, and an air turbine are used. The heat from flue gases and air is recovered in two heat exchangers, where heated water is used in the CO₂ capture system of the coal-fired power unit. The mass flow of the water cooling exchangers $HE_1$ and $HE_2$ is selected so that the temperature of flue gases and air at the exchanger outlet is at the level of 90 °C. The pinch between the cold inflow and hot outflow at exchangers $HE_1$ and $HE_2$ is maintained at approx. 10 °C, as the temperature of the re-circulating water is approx. 80 °C. Water is heated to the temperature of 135 °C. In the case of the flue gas exchanger, it is also important that the temperature does not drop below the dew point. Due to the possibility of corrosion, the direct flue gas–amine exchangers are not used here.

An important parameter affecting the efficiency of the gas-air cycle is the pressure ratio in the S2 compressor. The impact is illustrated in Fig. 5. The curves are plotted for three mass flows which correspond to 75, 100 and 125% of the mass of the flue gases from the gas turbine set, respectively. The optimum
parameters are obtained for the compression rate $\pi_2 = 5.1$ and the air mass equal to 112.7% of the flue gas mass $m_{sp}$. The electricity generation efficiency is then $\eta_{el} = 47.35\%$.

Figure 6 presents the amount of heat that can be absorbed by water in exchangers $\text{HE}_1$ and $\text{WC}_2$ for the needs of the coal-fired power unit $\text{CO}_2$ capture installation (simple system). For the air mass flow for which the electricity generation efficiency is the highest, the value of the heat absorbed by the water is not the highest. The heat that may be absorbed in the exchanger is given in relative units and defined by the dependence:

$$Q = \frac{Q_{HE1} + Q_{HE2}}{m_g LHV},$$

where $Q_{HE1,2}$ are the heat duty of heat exchangers 1 and 2, respectively, $m_g$ is the gaseous fuel mass flow, and $LHV$ denotes low calorific value. Using the presented curves, it is possible to determine the power capacity of the gas turbine and of the air cycle that would be able to provide a sufficient amount of heat for the $\text{CO}_2$ desorption process.

Based on the presented analyses of the simple air cycle, it is possible to achieve
the following parameters of the gas-air cycle co-operating with a coal-fired power plant:

- net power capacity of the gas turbine: 360.7 MW,
- net power capacity of the air turbine: 59.8 MW,
- net efficiency of the gas-air cycle: 0.45.

3 Savings in the fuel chemical energy

The savings in the fuel chemical energy after the application of dual-fuel gas and coal fired systems may be assessed assuming the same effects of the operation of the power systems. The indices that may be used for this purpose are the electricity generation efficiency, $\eta_{el}$, or the heat rate, defined as:

$$HR = \frac{m_f LHV}{N_{el}},$$

where $m_f LHV$ is the fuel chemical energy flux and $N_{el}$ is the net power capacity of the power plant.

A significant feature of multifuel power systems is the change in the electricity generation efficiency in the subsystems, compared to single fuel systems. In the case of the systems under analysis, where the gas cycle provides heat, a drop in efficiency related to the heat generation has to be taken into account. An example...
of a value which allows the determination of the savings in the chemical energy of fuels may be the index defined as follows:

$$HR_s = HR_{sep} - HR_{mf}.$$  \hspace{1cm} (3)

The essence of this index is to determine the difference between the fuel chemical energy consumption in separate single fuel systems ($HR_{sep}$) and in a multifuel system ($HR_{mf}$).

While considering hybrid gas and coal fired plants, two methodologies may be distinguished. In one, it is assumed that the system of the coal-fired plant is replaced with a gas and coal fired system. The HRs index determined in this case conforms to the effect of the application of this technology if there are no gas cycles in the plant under consideration. In this case, each new system that features a positive HRs index is also characterised by savings in the fuel chemical energy. In the other method, it is assumed that the effects of a coal-fired system operation in a hybrid plant replace the reference coal-fired system, and the effects of a gas-fired system replace the gas technology. The positive value of the HRs index in this case reduces the consumption of energy of primary fuels in a system composed of both coal-fired and gas-fired power units.

The values of the HR index for the systems under analysis are shown in Fig. 7. The presented values ignore the consumption of the energy of fuels related to their production and transport. The savings in the chemical energy of fuels may be determined by deducting the consumption of this energy in the assessed power plant from the consumption in the reference plant. The first bar in the chart...
illustrates the fuel chemical energy consumption in a power plant without a CO\textsubscript{2} capture installation. Due to a higher efficiency of this plant compared to the efficiency presented in Section 2 (resulting from lower own needs), the system features a lower consumption of the fuel energy. The next analysed system is a power plant with a CO\textsubscript{2} capture installation where bleed steam from the steam turbine is used for the desorption process. Because of a substantial drop in efficiency, the system features the highest chemical energy consumption. In the case of the considered gas and coal fired systems, the system with a gas turbine and a steam cycle with a backpressure turbine features the lowest, and the system with a gas turbine and a water boiler – the highest chemical energy consumption. It should be noted that all systems under analysis feature a lower consumption of chemical energy compared to a coal-fired system with CO\textsubscript{2} capture. In order to compare the chemical energy consumption when gas and coal fired systems are used, the appropriate values of the three systems under consideration are presented in the chart. It is assumed in the calculations that the coal-fired system replaces the reference coal-fired power plant with CO\textsubscript{2} capture and with an efficiency of 40.7\%, and the gas-fired system – a gas-fired plant with no CO\textsubscript{2} capture installation and with an efficiency of 52.5\%. The presented results indicate that in the case of a system with a gas turbine and a water boiler the energy consumption is the same as in the reference systems, whereas for the remaining gas and coal fired systems the chemical energy consumption is lower than for the reference ones.

4 Avoided emissions

The impact of a given power technology on the environment in the form of CO\textsubscript{2} emissions may be compared after assuming identical effects of the operation of power plants. As the main effect of a power plant operation is electricity, it is convenient to relate the amount of emitted CO\textsubscript{2} to the amount of electric power. The power plant CO\textsubscript{2} emissions factor may therefore be defined as follows:

\[ e = \frac{E}{N_{el}}, \]

where \( E \) is the mass flow of emitted carbon dioxide, \( N_{el} \) is the net power capacity of the power plant.

A significant feature of power plants with CO\textsubscript{2} capture is the lower value of the electricity generation efficiency compared to those without a CO\textsubscript{2} capture installation. In the case of methods based on chemical absorption of CO\textsubscript{2}, the
reduction in efficiency is related to the need to provide great amounts of heat for the absorption process. Consequently, a comparison of different power plants in terms of CO\textsubscript{2} emissions requires a determination of a value that accounts for the effects related to the reduction in the efficiency of plants with CO\textsubscript{2} capture. An example of such a value may be the avoided emissions factor (\(e_{av}\)). The essence of the factor is to define the difference between the direct effects of the impact of the reference and the assessed technologies:

\[
e_{av} = e_{ref} - e_{a},
\]  

(5)

where \(e_{ref}\) and \(e_{a}\) are the factors of reference system and assessed system respectively. A beneficial effect on the environment may be obtained if emissions determined for the technology with CO\textsubscript{2} capture are lower than those for a technology without it (\(e_{av} > 0\)).

While considering hybrid gas and coal fired plants, two methodologies may be distinguished. In one, it is assumed that the system of the coal-fired plant is replaced with a gas and coal fired system. The avoided emissions determined in
this case conform to the effect of the application of this technology if there are no gas cycles in the plant under consideration. Therefore, each new plant with positive avoided emissions has an advantageous impact on the environment by reducing the amounts of CO$_2$ released into the atmosphere. In the other method, it is assumed that the effects of the coal-fired system operation in a hybrid plant replace the reference coal-fired system, and the effects of the gas-fired system replace the gas technology. A positive value of avoided emissions in this case results in a beneficial effect on the environment in a power generation system composed of both coal-fired and gas-fired power plants.

The described methodology to determine the avoided emissions factor is presented in Figs. 8 and 9, using the emissions factors for the replaced reference system ($e_{c,g,\text{ref}}$), the assessed system ($e_{c,g,a}$), and the power capacity ratio ($\beta$):

\begin{align}
  e_{c,g,\text{ref}} &= \frac{E_{c,g,\text{ref}}}{N_{el,c,g}}, \\
  e_{c,g,a} &= \frac{E_{c,g,a}}{N_{el,c,g}}, \\
  \beta &= \frac{N_{el,c}}{N_{el,c} + N_{el,g}}.
\end{align}

Figure 8. The diagram of the determination of avoided emissions for a coal-fired power plant with a CO$_2$ capture installation: 1 – emission of reference coal fired power plant, 2 – emission of coal fired power plant with carbon capture system ($e_{c,\text{ccs}}$ – captured emission), 3 – avoided emission.

For a gas and coal-fired plant, it is possible to define the dependences between their power capacities, that guarantee that a positive value of avoided emissions
Figure 9. The diagram of the determination of avoided emissions for a hybrid coal and gas-fired power plant for different replaced systems: methodology 1 (a), and methodology 2 with a CO₂ capture installation (b) (1 – emissions of reference power plants, 2 – emission of coal-fired power plant with carbon capture system (e_{ccs} – captured emission), 3 – avoided emission).

is obtained: for first methodology

\[
\frac{N_{el,g}}{N_{el,g} + N_{el,d}} > \frac{e_{el,ref} - e_{g,ref}}{e_{el,ref} - e_{g,ref}}
\]  

(9)

and for second methodology

\[
\frac{N_{el,c}}{N_{el,g}} > \frac{e_{g,ref} - e_{g,ref}}{e_{g,ref} - e_{g,ref}}
\]  

(10)

Figure 8 presents the methodology to determine avoided emissions for a plant with CO₂ capture, in which the heat source is steam from the steam turbine bleeds of a coal-fired plant. The plant with the capture installation has a higher emissions factor due to lower efficiency. This causes that the avoided emissions are smaller than the captured emissions. Figure 9a shows the emissions factor values for the hybrid coal and gas-fired plant and the coal-fired plant (the replaced one). Because the emissions factor for a gas-fired plant is low, a situation may arise in which captured emissions are smaller than avoided emissions. The chart 9b presents emissions factors for hybrid plants and for the coal-fired and gas-fired systems as the ones to be replaced.

In order to determine the effect of the proportion of the gas to steam cycles on the emissions and energy efficiency of the whole system, three variants of the system are considered:

- system with a gas turbine with a water boiler (GT+WB);
system with a gas-steam cycle characterised by the net electricity generation efficiency equal to 47% and overall efficiency equal to 74% (CC);

system with a gas-steam cycle characterised by the net electricity generation efficiency equal to 53% and overall efficiency equal to 62% (HECC).

The dependence of the emissions factor calculated using formula (1) and of the net electricity generation efficiency on the $\beta$ parameter is illustrated in Fig. 10. In addition, the figure presents the real achievable values of $\beta$ for the respective systems in the form of arrows. Analysing the dependence of emissions on $\beta$, it can be concluded that the high-efficiency clean combustion (HECC) system features lower emissions than the other variants. However, the $\beta$ values which may be achieved in a real system are low, which can in consequence lead to higher CO$_2$ emissions. As for the dependence of the electricity generation efficiency on $\beta$, it can be seen that an increase in the share of electricity produced from coal raises the efficiency of the system for the low efficiency gas cycle, and lowers it for the high efficiency gas-steam cycle.

The value of avoided emissions for each system using the first methodology can be read from the chart as the difference of ordinates of the system without a CO$_2$ capture installation, and analysed. In order to determine avoided emissions, and taking account of both methodologies, CO$_2$ emissions for the same systems as those analysed in Section 3 are presented in Fig. 11. The coal-fired system with no CO$_2$ capture features the highest CO$_2$ emissions, which is related to the high content of carbon in the fuel. The system with CO$_2$ capture features the lowest emissions which result from the fact that CO$_2$ is not separated entirely and from the system reduced efficiency. All the gas and coal fired systems feature much lower emissions than the coal-fired system without the CO$_2$ capture installation, and by 83–102% higher compared to the coal-fired system with CO$_2$ capture.

In order to find the CO$_2$ emissions in the replaced coal-fired systems, it is assumed that the gas-fired power plant with an efficiency of 52.5% is characterised by emissions at the level of 377 kg/MW and that this is a system without CO$_2$ separation. Two systems are analysed in the case of the reference coal-fired power plant:

- coal-fired system with CO$_2$ capture, with an efficiency of 40.7% and CO$_2$ emissions of 105 kg/MWh;

- coal-fired system without CO$_2$ capture, with an efficiency of 47.2% and CO$_2$ emissions of 726 kg/MWh.
All the analysed coal and gas fired systems feature a much lower emissivity compared to the replaced power plants without CO₂ capture. The system with a gas turbine and a water boiler features the highest avoided emissions.

When gas and coal fired systems are compared to the reference power plants where the coal-fired power unit is equipped with the capture installation, the gas
and coal fired systems are characterised by higher emissions, and the smallest difference is for the system with a gas turbine and a steam cycle ($\varepsilon_{av} = -5$ kg/MW).

5 Conclusions

Efforts to reduce CO$_2$ emissions in power engineering have made it possible to use new concepts of gas and coal fired systems. The performed analyses of the examples of gas and coal fired systems are characterised by the fact that the heat obtained from gas-fired systems is used for the desorption process of CO$_2$ produced in the coal-fired systems. The essential features of these systems, which were identified at the beginning and which became the stimulus for deeper studies, are: a possibility of fuel source diversification in the process of electricity generation and a construction of a system featuring a high electricity generation efficiency – even if there is no need for CO$_2$ capture, which involves a lower investment risk.
The analyses of the three gas and coal fired systems make it possible to draw the following conclusions:

- Combined gas and coal fired systems allow the achievement of savings in the chemical energy of fuels compared to separate systems where the coal-fired plant is equipped with the CO$_2$ capture installation.
- The system with a gas turbine and a steam cycle with a backpressure turbine features the lowest energy consumption.
- The analysed systems are characterised by much lower CO$_2$ emissions than those in separate systems with no CO$_2$ capture.
- The analysed systems are characterised by similar CO$_2$ emissions compared to those in separate systems with a CO$_2$ capture installation in the coal-fired plant.

The presented results together with the results of economic analyses [18] suggest that these systems are interesting from the point of view of energy generation, ecology and economy. However, due to the fact that the results often differ only slightly, the decision concerning the commercial application of any of the systems has to be preceded by more detailed studies.

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Układy dwupaliwowe gazowo-węglowe — koncepcje nowych zastosowań

**Streszczenie**

Polityka energetyczna związana z ograniczeniem emisji CO2 powoduje, że interesujące jest rozważanie nowych koncepcji układów wielopaliwowych. W pracy poddano analizie układy węglowo-gazowe, w których ciepło spalin z układu gazowego wykorzystywane jest do zasilania układu separacji CO2 z siłowni opalanych węglem. Analizowane struktury oceniono pod względem oszczędności energii chemicznej paliwa oraz emisji unikniętej CO2.
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Stan i perspektywy rozwoju układów gazowo-parowych


1 Wprowadzenie

Miara doskonałości obiegu termodynamicznego może być sprawność Carnota

$$\eta_C = 1 - \frac{T_w}{T_d},$$

gdzie $T_w$ i $T_d$ oznaczają odpowiednio średnią temperaturę wyprowadzenia i doprowadzenia ciepła do obiegu, [K]. W konwencjonalnej, parowej elektrowni kondensacyjnej, średnią temperaturę doprowadzenia ciepła do czynnika roboczego jest stosunkowo niska i zawiera się na ogół w przedziale 290–430 °C [1]. Granica górna uzyskiwana jest dla obiegów z przegrzewem międzystopniowym. Aktualnie rozpatrywane projekty elektrowni na parametry nadkrytyczne podnoszą tą

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temperaturę zazwyczaj nie więcej niż o 20 °C. W układzie parowym ciepło doprowadzone jest do obiegu w kotle (poprzez przeponę), który stanowi wymiennik ciepła. Temperatura spalania w kotle może przekraczać nawet 1700 °C [2], a temperatura pary w klasycznych rozwiązaniach jest równa 540 °C; w nowoczesnych rozwiązaniach ≥ 600 °C. Strata wylotowa związana z wyprowadzeniem spalin o temperaturze znacznie większej od temperatury otoczenia jest duża. Wymiana ciepła w kotle z czynnikiem i otoczeniem jest także przyczyną powstania strat.

W obiegu parowym ciepło wyprowadzone jest do otoczenia na tzw. zimnym końcu w temperaturze leżącej w zakresie 40–80 °C. W konsekwencji sprawność obiegu wyznaczona z (1) wynosi 37–57%, przy czym dla układów z przegrzewem międzystopniowym będą to wartości wyższe od podanych (46–57%), dla układów bez przegrzewu niższe (37–50%). W układzie turbiny gazowej ciepło doprowadzone jest do obiegu w komorze spalania, wprost bez przeponowego wymiennika. Średnia temperatura doprowadzenia ciepła jest bardzo wysoka i zawiera się w przedziale 680–810 °C [1,2]. Wartość maksymalna osiągana może być w instalacjach z sekwencyjną komorą spalania, w układach prostych jest ona o około 50 °C niższa. Średnia temperatura ciepła wyprowadzonego jest jednak w układzie turbiny gazowej bardzo wysoka (230–280 °C). W konsekwencji sprawność wyznaczona zależnością (1) oscyluje w przedziale 42–49,5%. Połączenie obydwu układów (rys. 1) w instalację gazowo-parową skutkuje zachowaniem zalet i likwidacją wad układów analizowanych autonomicznie. Powstały (rys. 1c) układ gazowo-parowy zachowuje wysoką temperaturę doprowadzenia ciepła z instalacji gazowej (bez przeponowego wymiennika), oraz niską temperaturę wyprowadzenia ciepła z instalacji parowej. W konsekwencji z (1) otrzymujemy 63% ≤ η_C ≤ 70%.

2 Charakterystyka stosowanych rozwiązań

Sprawność wytwarzania energii elektrycznej w eksploatowanych elektrowniach gazowo-parowych opalanych gazem ziemnym jest na skutek nieodwracalności zjawisk oczywiście niższa niż wyznaczona w oparciu o równanie (1), co pokazano w tab. 1. [3]. Wraz z rozwojem technologii budowy turbin gazowych ciągle jedna rośnie i aktualnie osiągnęła w najlepszych rozwiązaniach granicę 60%. Ten wzrost sprawności pokazano to na rys. 2 [4].

Tabela 1. Charakterystyka wybranych układów gazowo-parowych (oznaczenia: 1W, WW – układ jedno- i wielovalowy, 1+1+1 – jedna turbina gazowa + jeden kocioł odzyskowy + 1 turbina parowa)

<table>
<thead>
<tr>
<th>Charakterystyka układu</th>
<th>3PR</th>
<th>3P</th>
<th>3PR</th>
<th>3P</th>
<th>3P</th>
<th>3P</th>
<th>3P</th>
<th>3P</th>
<th>3P</th>
<th>3P</th>
</tr>
</thead>
<tbody>
<tr>
<td>Konfiguracja</td>
<td>1+1+1</td>
<td>2+2+1</td>
<td>2+2+1</td>
<td>1+1+1</td>
<td>3+3+1</td>
<td>3+3+1</td>
<td>3+3+1</td>
<td>2x (2+2+1)</td>
<td>3x (1+1+1)</td>
<td>2x (2+2+1)</td>
</tr>
<tr>
<td>Klasa turbiny gazowej</td>
<td>F</td>
<td>E</td>
<td>F</td>
<td>E</td>
<td>E</td>
<td>E</td>
<td>E</td>
<td>F</td>
<td>E</td>
<td>E</td>
</tr>
<tr>
<td>Napęd</td>
<td>1W</td>
<td>WW</td>
<td>1W</td>
<td>WW</td>
<td>WW</td>
<td>WW</td>
<td>WW</td>
<td>WW</td>
<td>WW</td>
<td>WW</td>
</tr>
<tr>
<td>Moc netto</td>
<td>MW</td>
<td>390</td>
<td>487,3</td>
<td>780</td>
<td>731</td>
<td>787,5</td>
<td>786,4</td>
<td>974,6</td>
<td>1170</td>
<td>1170</td>
</tr>
<tr>
<td>Sprawność netto</td>
<td>%</td>
<td>57,1</td>
<td>53,43</td>
<td>57,1</td>
<td>53,44</td>
<td>51,18</td>
<td>52,43</td>
<td>53,43</td>
<td>57,1</td>
<td>51,09</td>
</tr>
<tr>
<td>Całkowite nakłady inwest.</td>
<td>min</td>
<td>USD</td>
<td>225</td>
<td>275,4</td>
<td>427,1</td>
<td>393,3</td>
<td>389,8</td>
<td>413,4</td>
<td>524,8</td>
<td>624,9</td>
</tr>
<tr>
<td>Jed. nakłady inwest.</td>
<td>USD/kW</td>
<td>577</td>
<td>565</td>
<td>548</td>
<td>538</td>
<td>495</td>
<td>526</td>
<td>533</td>
<td>534</td>
<td>479</td>
</tr>
</tbody>
</table>
Rysunek 2. Zależność sprawności układu kombinowanego od temperatury na wlocie do turbiny


z turbiny parowej (TP) z generatorem (G), kotła odzyskowego trójciśnieniowego z przegrzewem międzystopniowym (KO), kondensatora (KND), odgazowywacza (OD) i pomp.

W obliczeniach tego układu przedstawionych w [6,7] model turbiny oparty został na turbinie Westinghouse 501G (1995 GTW) o mocy elektrycznej 228,9 MW i sprawności 38,24%. Turbina jest chłodzona w sposób "klasyczny" za pomocą powietrza pobranego za sprężarkę co pokazano na rys. 4 linią przerywaną. Stosunek strumienia powietrza chłodzącego do strumienia powietrza sprężanego wynosi 16%. Optymalizacja parametrów części parowej układu doprowadziła do
sprawności elektrowni 58% przy mocy 348,2 MW.
Sprawności pokazane na rys. 3 podobnie jak ostatnia podana wartość, odnoszą się do klasycznej metody chłodzenia tj. chłodzenie powietrzem w układzie otwartym. Chłodzony jest pierwszy i drugi stopień turbiny. Powietrze chłodzące miesza się ze spalinami przepływającymi przez turbinę [8].

Układy gazowo-parowe opalane gazem ziemnym zawdzięczają swój rozwój, oprócz wymienionej już wysokiej sprawności, licznym innym zaletom, z których najważniejsze to:

- bardzo korzystne charakterystyki ekologiczne,
- duża elastyczność cieplna prowadząca do stosunkowo krótkich czasów wymaganych dla osiągnięcia pełnego obciążenia,
- duża niezawodność działania,
- łatwość obsługi i automatyzacji procesów eksploatacyjnych,
- stosunkowo niskie nakłady inwestycyjne,
- szybki czas budowy.
3 Charakterystyka sposobów zwiększania sprawności

Zwiększenie sprawności układów gazowo-parowych zasadniczo poszukiwane jest na drodze zwiększenia średniej temperatury doprowadzenia ciepła do obiegu gazowego. Realizowane to jest poprzez wzrost temperatury spalin na wlocie do turbiny gazowej lub prowadzenie tak zwanego sekwencyjnego spalania. Przykładem tego ostatniego jest turbina gazowa GT26, która podzielona jest na część wysoko i niskoprężną i przed każdą z nich jest komora spalania. Spalanie odbywa się sekwencyjnie najpierw w pierwszej komorze spalania, a po rozprężeniu spalin w części wysokoprężnej w drugiej komorze spalania. Temperatura spalin na wlocie do turbiny gazowej (TIT – turbine inlet temperature, $t_{3a}$) w najlepszych komercyjnych rozwiązaniach osiągnęła około 1430 °C (np. turbina MS 7001H) i ciągle się zwiększa. Statystycznie wzrost ten wynosi około 13 °C/rok [9]. Firma Siemens w oparciu o turbinę klasy H opracowała układ SGT6-8000H o mocy wyjściowej 578 MW i sprawności nieco wyższej niż 60% [10]. Pierwszą turbinę uruchomiono w maju 2011 r. Podobną ofertę posiada General Electric-MS9001H(9H) [11]. Grupa MHI (Mitsubishi Heavy Industries Ltd.) w lutym 2011 r. rozpoczęła prace nad testową turbiną klasy J (M501J) zainstalowaną w układzie kombinowanym o mocy 460 MW (60 Hz) i przewidywanej sprawności 60% [12]. Temperatura wlotowa do tej turbiny wynosi 1600 °C, co jest poziomem o ok. 100 °C wyższym od turbin poprzedniej generacji (klasa G-M701G2 – sprawność układu kombinowanego wynosi 59,1%). Podnoszenie temperatury wlotowej wymaga chłodzenia elementów narażonych na jej działanie, co wiąże się także ze stratą sprawności. Oprócz nowych materiałów na łopatki turbiny poszukuje się nowych metod chłodzenia. Zasadniczo oprócz wspomnianego już chłodzenia powietrzem w układzie otwartym analizowane są [13]:

a) chłodzenie parą w układzie zamkniętym zarówno łopatek kierowniczych jak i wirnikowych,

b) użycie dwóch niezależnych zamkniętych układów: pary dla łopatek kierowniczych, powietrza dla łopatek wirnika.

Przykład elektrowni gazowo-parowej z kotłem trójciśnieniowym z turbiną gazową z sekwencyjną komorą spalania oraz z chłodzeniem parowym w układzie zamkniętym pokazano na rys. 5 [9]. Wyniki obliczenia sprawności układu z kotłem trójciśnieniowym (z rys. 5) przy rozważaniu różnych sposobów chłodzenia w funkcji temperatury na wlocie do turbiny gazowej pokazano na rys. 6 [9]. Pozwalają one sformułować następujące wnioski:

a) Dla konwencjonalnego chłodzenia powietrzem w układzie zamkniętym wzrost
sprawności układu gazowo-parowego wynosi ok. 1%/100 °C. Dla \( t_{3a} = 1430 \, ^\circ\text{C} \) sprawność układu wynosi 58,4%. Sprawność 60% będzie osiągnięta dla temperatury spalin na wlocie do turbiny gazowej \( t_{3a} = 1650 \, ^\circ\text{C} \) (krzywa I na rys. 6).

b) Dla parowego zamkniętego układu chłodzenia wzrost sprawności elektrowni ze wzrostem \( t_{3a} \) jest nieco wyższy niż w poprzednim przypadku, przy czym dotyczy zdecydowanie wyższych wartości. Bowiem dla temperatury \( t_{3a} = 1430 \, ^\circ\text{C} \) sprawność wynosi już 60,2% i rośnie o dalsze 0,5% dla temperatury \( t_{3a} = 1500 \, ^\circ\text{C} \) (krzywa II na rys. 6).

c) Dla parowego zamkniętego układu chłodzenia i przy zastosowaniu turbiny gazowej ze spalaniem sekwencyjnym sprawność układu rośnie liniowo do temperatury \( t_{3a} = 1350 \, ^\circ\text{C} \), dalsze zwiększenie tej temperatury powoduje jedynie niemal wzrost sprawnost. Sprawność 60% osiągnięto dla \( t_{3a} = 1270 \, ^\circ\text{C} \) (krzywa III na rys. 6). W oparciu o zmodernizowaną turbinę GT26 ze spalaniem sekwencyjnym w czerwcu 2011 r. firma Alstom zaprezentowała układ kombinowanej generacji KA26 o mocy powyżej 500 MW i sprawności ok. 61% [14].

dwa różne sposoby pokazane na rys. 7. W pierwszym pokazanym na rys. 7a para pobierana jest z wylotu części wysokoprężnej turbiny parowej, w drugim przypadku pobierana do chłodzenia jest para nasycona z parowacza. Sprawność drugiego układu jest o 0,6 punktu procentowego wyższa niż pierwszego (analizowano układ jednocięśniowy). W przypadku poboru pary z wylotu części wysokoprężnej do chłodzenia (tak jak na rys. 7a) należy także analizować wpływ ciśnienia tej pary na sprawność układu [16].

Poprawienia sprawności elektrowni gazowo-parowej należy także poszukiwać w podniesieniu sprawności części parowej układu. Zasadnicze kierunki postępowania są takie same jak przy analizie elektrowni kondensacyjnej i sprowadzają się do:

• zwiększenia parametrów pary świeżej (temperatury i ciśnienia) na wlocie
do turbiny parowej oraz obniżeniu ciśnienia w kondensatorze,

- zwiększenia sprawności izentropowej turbiny parowej.

Główne powody ograniczające temperaturę pary świeżej w elektrowni gazowo-
parowej to:

- Zbyt niska temperatura spalin na wlocie do kotła odzyskowego co pokazano dla kilku przykładów w tab. 2 [17]. Z danych tych wynika, że w zasadzie tylko dla turbiny GT26 można by rozważyć produkcję pary o temperaturze 585 °C (595 °C). W pozostałych przypadkach temperatura ta musi być niższa.

- Brak odpowiednich rozwiązań materiałowo-konstrukcyjnych dla części parowej małej mocy (w instalacjach gazowo-parowych moc turbiny parowej z reguły nie przekracza 150 MW) [18]. Dla układów parowych kondensacyjnych dużej mocy takie materiały są już dostępne dla temperatury pary rzędu 600 °C, a nawet 650 °C, a w ciągu dekady będą osiągalne dla temperatury 700 °C i ciśnienia 35 MPa.

Tabela 2. Parametry charakterystyczne wybranych turbin gazowych

<table>
<thead>
<tr>
<th>Parametr</th>
<th>General Electric PG7251 (7FB)</th>
<th>Siemens V94.3A</th>
<th>Alstom Power GT26</th>
<th>Mitsubishi M701G</th>
</tr>
</thead>
<tbody>
<tr>
<td>Liczba stopni / liczba chłodzonych rzędów / liczba rzędów z powłoką ochronną / liczba rzędów z chłodzeniem filmem</td>
<td>3/5/2/1</td>
<td>4/6/2/1</td>
<td>h*: 1/2/2/1</td>
<td>4/6/4/3</td>
</tr>
<tr>
<td>Strumień spalin wylotowych [kg/s]</td>
<td>448,4</td>
<td>644,0</td>
<td>562,0</td>
<td>737,1</td>
</tr>
<tr>
<td>Spręż</td>
<td>18,5</td>
<td>17</td>
<td>30</td>
<td>20</td>
</tr>
<tr>
<td>Temperatura na wlocie turbiny [°C]</td>
<td>1402</td>
<td>1350</td>
<td>1255</td>
<td>1430</td>
</tr>
<tr>
<td>Moc netto [MW]</td>
<td>184,4</td>
<td>269</td>
<td>262</td>
<td>334</td>
</tr>
<tr>
<td>(185,5)</td>
<td>(259,3)</td>
<td>(264,9)</td>
<td>(330,1)</td>
<td></td>
</tr>
<tr>
<td>Sprawność netto [%]</td>
<td>36,92</td>
<td>38,20</td>
<td>38,20</td>
<td>39,55</td>
</tr>
<tr>
<td>(37,04)</td>
<td>(38,17)</td>
<td>(38,04)</td>
<td>(39,32)</td>
<td></td>
</tr>
<tr>
<td>Temperatura na wylocie turbiny [°C]</td>
<td>625,0</td>
<td>584,0</td>
<td>640</td>
<td>587,2</td>
</tr>
<tr>
<td>(625,1)</td>
<td>(582,7)</td>
<td>(638,8)</td>
<td>(585,6)</td>
<td></td>
</tr>
</tbody>
</table>

*h – część wysokoprężna ekspandera, l – część niskoprężna ekspandera

Bariera 61,5% sprawności układu kombinowanego może być osiągnięta do 2015 r. Sprawność rzędu 62–65% wymaga opracowania technologii chłodzenia turbin klasy J i wprowadzenia turbiny o temperaturze wlotowej 1700 °C [4]. Związane jest
to z wprowadzeniem superżaroodpornych materiałów, zaawansowanych powłok termicznych TBC (*thermal barrier coating*), optymalizację chłodzenia parowego, dalszej poprawy charakterystyk sprężarki i turbiny. Rozwiązywania wymaga także problem emisji NO\(_x\), szczególnie w turbinnie klasy 1700 °C, w wyprodukowanej przez MHI prototypie wprowadzono komorę spalania z recyrkulacją części spalin wylotowych z kotła odzyskowego do wlotu sprężarki powietrza [4].

4 Elektrownie gazowo-parowe z instalacjami sekwestracji dwutlenku węgla

Dalszy rozwój układów gazowo-parowych związany będzie także z korzystnymi charakterystykami ekologicznymi, w tym głównie emisją dwutlenku węgla. Elektrownie gazowo-parowe emitują bowiem przy sprawności 60% ok. 330 kgCO\(_2\)/MWh wobec 860 kgCO\(_2\)/MWh dla elektrowni konwencjonalnych opalanych węglem kamiennym, przy sprawności 40%, czy też 730 kgCO\(_2\)/MWh dla bloku nadkrytycznego opalanego węglem (600 MW, 28,5 MPa/600 °C, 5,1 MPa/620 °C) o sprawności brutto 48,8% [19]. Pomimo niskiej emisji CO\(_2\) w układach gazowo-parowych poszukuje się rozwiązań pozwalających je jeszcze znacząco ograniczyć lub wyeliminować zupełnie. Dla tradycyjnych układów kombinowanych wyposażonych w kocioł odzyskowy można bez większych problemów konstrukcyjnych zastosować absorbcyjną instalację wychwytu CO\(_2\) ze spalin. Chemiczna absorpcja przy użyciu aminy np. MEA (monoetanoloamina), DEA (dietanoloamina) wymaga głębokiego oczyszczenia spalin, zwłaszcza z SO\(_2\) (do 10 g/GJ lub 10 ppm wg [20]) oraz NO\(_x\) (do 30 g/GJ lub 20 ppm wg [20]). Usunięcie tych składników związane jest z rozszerzeniem czasu użytkowania rozpuszczalnika (MEA), którego z kolei regeneracja wymaga dużej ilości pary średnio i niskoprężnej, co jest także powodem tak znacznej obniżki sprawności bloku energetycznego. Regeneracja pochłania bowiem około 3–6 MJ ciepła do usunięcia 1 kg CO\(_2\) [21]. W przypadku spalin opuszczających komorę spalania zawartość SO\(_2\) zależy od składu gazu, dla gazów niskozasiarczonych zwykle jest mniejsza niż wymagana. Zawartość NO\(_x\) przy stosowanych metodach ograniczenia tej emisji ≤10 ppm. Utrzymywanie tej zawartości będzie trudne dla bardzo wysokich wartości temperatury wlotowej, np. dla TIT=1700 °C, NO\(_x\)= 34–38 ppm [4].

Absorpcyjną instalację separacji CO\(_2\) pokazano na rys. 8. Podłączona jest do układu gazowo parowego z rys. 4. w punkcie A (spaliny) oraz B (para) zaznaczonych na obydwu wymienionych rysunkach.

W koncepcji pokazanej na rys. 8. CO\(_2\) jest separowane ze spalin wylotowych przy użyciu 30% roztworu monoethanolaminy (MEA). Spaliny zawierające 3,9% (obj.)
CO₂ są chłodzone do temperatury 40 °C i doprowadzone do wieży absorbera (WA). Zakłada się, że 90% emitowanego CO₂ zostanie wychwycone. Roztwór aminy bogaty w CO₂ doprowadzony jest do desorbera (AS), z którego zregenerowana MEA wraca do wieży absorbera. Wymagane do regeneracji ciepło w ilości 3,6 MJ/kg wychwyconego CO₂ dostarczone jest z parą (4 bar, 140 °C, punkt B) z upustu turbiny parowej. Uwodniona mieszanina CO₂ i pary w kondensatorze jest ochłodzona w celu usuwania wody, zaś CO₂ jest sprężone do ciśnienia wymaganego do transportu (200 bar).

Na rys. 9 pokazano układ kombinowany ze spalaniem tlenowym. Spaliny wyłotowe z turbiny gazowej zawierają głównie H₂O i CO₂. Woda jest wykrapiana w kondensatorze za kotłem odzyskowym (KO). Około 90% CO₂ jest zawrócone przez sprężarkę (K) do komory spalania (KS) aby utrzymać temperaturę na wlocie do turbiny gazowej na wymaganym poziomie. Opuszczający układ CO₂ sprężany jest w stacji sprężania (K) do ciśnienia 200 bar.

Na rys. 10 przedstawiono koncepcję zero-emisyjnego układu AZEP (advanced zero emission power plant). Komorę spalania z układu klasycznego zastąpiono w nim reaktorem membranowym MCM (mixed conductive membrane). Reaktor ten ma trzy zasadnicze funkcje [22]:

a) separatora membranowego O₂ z powietrza,

b) komory spalania tlenowego dostarczanego paliwa,

c) wymiennika ciepła (podgrzewanie czynnika zasilającego turbinę T).

Powietrze pozbawione tlenu po rozprężeniu w turbinie ekspansyjnej zasila kocioł
odzyskowy (KO). Spaliny z reaktora MCM zawierające głównie mieszaninę CO₂ i H₂O. Po rozprężeniu w turbince [CO₂/S]T odseparowana jest z nich woda a CO₂ sprężane jest do wymaganego ciśnienia (200 bar).
Stan i perspektywy rozwoju układów gazowo-parowych

Sprawność netto wytwarzania energii elektrycznej w analizowanych układach pokazanych na rys. 8–10 wyrażona jest zależnością:

\[ \eta_{el} = \frac{\sum_i N_{el} - \sum_i N_{ai}}{\dot{m}_F \cdot LHV} = \frac{\sum_i N_{el} (1 - \delta)}{\dot{m}_F \cdot LHV} = \eta_{el,br} (1 - \delta), \]

gdzie: \( \sum_i N_{el} \) – suma mocy elektrycznej generatorów zainstalowanych w układzie [MW], \( \sum_i N_{ai} \) – moc potrzeb własnych [MW], \( LHV \) – wartość opałowa [MJ/kg], \( \dot{m}_F \) – strumień paliwa, [kg/s], \( \delta \) – wskaźnik potrzeb własnych, \( \eta_{el,br} \) – sprawność wytwarzania energii elektrycznej brutto.

Zastosowanie instalacji sekwestracji CO\(_2\) (CCS) (carbon capture and storage) w elektrowniach obniża sprawność wytwarzania energii elektrycznej. Wynika to głównie ze wzrostu wskaźnika potrzeb własnych elektrowni, który wyraża stosunek mocy potrzeb własnych odniesionych do mocy brutto bloku energetycznego. Proponuje się go zapisać w postaci:

\[ \delta = \delta_1 + \delta_2 + \delta_3, \]

gdzie: \( \delta_1 \) uwzględnia moc urządzeń pomocniczych stosowanych zarówno w elektrowni bez, jak i z układem CCS (dotyczy to np. wentylatorów, pomp kondensacyjnych i cyrkulacyjnych), \( \delta_2 \) związany jest z systemem wychwytywania CO\(_2\) a \( \delta_3 \) uwzględnia moc kompresorów sprężających odseparowany CO\(_2\).

Powodem obniżania sprawności \( \eta_{el} \) może być także niższa sprawność sprawności brutto. Układem odniesienia dla analizowanych koncepcji jest elektrownia gazowo-parowa z kotłem trójciśnieniowym z przegrzewem międzystopniowym o strukturze przedstawionej na rys. 4. Moc tej elektrowni wynosi 400 MW, a sprawność netto 56,7% (zastosowano w niej turbinę klasy F o symbolu GE9351FA, w której temperatura wlotowa jest równa 1328 °C). Sprawność brutto i netto oraz wartości wskaźników \( \delta \) zestawiono dla analizowanych układów w tab. 3 [22]. Pokazano tam także różnicę (\( \Delta \)) pomiędzy sprawnością netto elektrowni odniesienia i analizowanych układów. Dla układu z rys. 8 zastosowaną MEA (kolumna oznaczona jako MEA w tab. 3) maleje sprawność brutto elektrowni poprzez zmniejszenie mocy turbiny parowej w związku z poborem pary do układu separacji, zaś wskaźnik \( \delta_2 \) w tym przypadku związany jest z koniecznością podniesienia ciśnienia spalin wylotowych dla kompensacji strat ciśnienia w kolumnie absorpcyjnej. Dla układu ze spalaniem tlenowym wskaźnik \( \delta_2 \) = 14,7% obejmuje kriogeniczną produkcję (10,7%) i sprężanie tlenu (4%). Dla układu AZEP rozpatrywano dwa przypadki:
(1) ze 100% wychwytem CO₂ (TIT = 1200 °C – ze względu na ograniczenia reaktora),

(2) z 85% wychwytem CO₂ (TIT = 1328 °C – wówczas sprawność brutto elektrowni gazowo-parowej jest o 2,5 punktu procentowego wyższa niż w przypadku (1)).

Tabela 3. Sprawności brutto, netto oraz wskaźniki potrzeb w łasnych analizowanych układów

<table>
<thead>
<tr>
<th>Jedn. [%]</th>
<th>Elektrownia g-p</th>
<th>MEA</th>
<th>Sp. tlenowe</th>
<th>AZEP 100%</th>
<th>AZEP 85%</th>
</tr>
</thead>
<tbody>
<tr>
<td>η_{el,br}</td>
<td>57,6</td>
<td>53,3</td>
<td>59,7</td>
<td>51,7</td>
<td>54,2</td>
</tr>
<tr>
<td>δ₁</td>
<td>1,6</td>
<td>2,1</td>
<td>1,5</td>
<td>1,4</td>
<td>1,5</td>
</tr>
<tr>
<td>δ₂</td>
<td>–</td>
<td>3,8</td>
<td>14,7</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>δ₃</td>
<td>–</td>
<td>4,3</td>
<td>5,0</td>
<td>1,9</td>
<td>1,5</td>
</tr>
<tr>
<td>δ</td>
<td>1,6</td>
<td>10,1</td>
<td>21,3</td>
<td>3,3</td>
<td>3,0</td>
</tr>
<tr>
<td>η_{el}</td>
<td>56,7</td>
<td>47,9</td>
<td>47,0</td>
<td>50,0</td>
<td>52,6</td>
</tr>
<tr>
<td>Δ</td>
<td>–</td>
<td>8,8</td>
<td>9,7</td>
<td>6,8</td>
<td>4,2</td>
</tr>
</tbody>
</table>

5 Uwagi końcowe

- Ważnym czynnikiem w rozwoju układów gazowo-parowych opalanych gazu ziemnym są ich niezwykle korzystne charakterystyki ekologiczne. Szczególnego znaczenia w ostatniej dekadzie nabiera ich niska emisja CO₂ — 380 kg/MWh przy sprawności 60%.

- Elektrownie gazowo-parowe osiągają najwyższe z możliwych sprawności konwersji energii chemicznej paliwa do energii elektrycznej, zachowując jednocześnie potencjał zwiększania tej wielkości.

- Bariera 61,5% sprawności układu kombinowanego może być osiągnięta do 2015 roku. Sprawność rzędu 62-65% wymaga dojrzałości technologicznej turbin klasy J i wprowadzenia turbin o temperaturze wlotowej 1700 °C. Osiągnięta ona będzie po dopracowaniu systemów chłodzenia i ograniczenia emisji NOₓ.

- Można rozważać wiele koncepcji elektrowni gazowo-parowych z instalacją CCS. Rozwiązania wykorzystujące absorpcję chemiczną CO₂ mogą być wdrażane w krótkim okresie czasu. Prowadzą one do obniżenia sprawności o 9 punktów procentowych względem układu odniesienia (bez instalacji
Stan i perspektywy rozwoju układów gazowo-parowych

Zmniejszenie tej wartości poszukuje się przez wprowadzenie nowych mniej energochłonnych absorbentów. Układy przyszłościowe zaawansowane technologicznie po rozwiązaniu szeregu problemów naukowo-technicznych prowadzić mogą do niewielkiego zmniejszenia sprawności, rzędu 4 punktów procentowych.

Praca wpłynęła do redakcji w czerwcu 2012r.

Literatura

The paper focuses on a natural gas-fired combined cycle plants. Thermodynamic efficiency issues of these plants are discussed. Different concepts of the improvement of this parameter are presented starting from temperature increase at the gas turbine inlet through the cooling system arrangement to the increase of steam cycle efficiency. The latest solutions of world leaders in production of gas turbines and combined cycle plants were characterized. The following concepts of these plants were presented: a plant with an absorption installation with the use of MEA, a plant with oxy-fired combustion chamber and an advanced concept of zero-emission plant with a membrane reactor. The efficiency and CO$_2$ emission of these concepts were presented.
Technical and economical analysis of exploitation of gas fired small scale combined heat and power systems in Poland

Paper presents an estimation of influence of selected technical and financial parameters on the cost-effectiveness of the small scale cogeneration systems in Poland. The influence of electrical efficiency of the combined heat and power (CHP) module and power-to-heat ratio on the exploitation costs and incomes of the whole cogeneration system has been analysed. Analysis has been carried out on the example of small scale CHP with the reciprocating internal combustion (IC) gas engine or gas turbine fired by natural gas or coal bed methane.

1 Introduction

During two last decades one can observe in Poland an increase of number and total power of distributed power generation units fired by gas fuels (especially cogeneration units). More and more important share of them are small scale combined heat and power (CHP) systems [1,2]. Profits given by cogeneration technology are mainly of thermodynamic nature and leads to the possibility of decrease of primary energy consumption (and emissions to the environment) when comparing to separate power and heat generation. Majority of being under exploitation CHP units are of small scale and can be classified as distributed power generation systems. The most significant feature of distributed power generation units is in situ power consumption. The surplus of electricity can be sold to the grid.

More and more CHP units are fired by gaseous fuels due to the following important premises:
• relatively high efficiency of power generation and low emissions,
• permanent technical improvement of new constructions of CHP modules
  (reciprocating gas engines, gas turbines and microturbines),
• low demand for the site,
• optimal sizing towards consumer demands,
• possibility of utilization of special fuels without fuel transportation (bio-
gases, coal bed methane etc.).

Small scale cogeneration systems are installed usually in locations where demand
for power and heat appears during significant part of the year. Usually, time
distribution of power and heat demand changes during the day and depends on
several factors, i.e., season, industrial technology etc. Variation and volume of de-
mand for electricity and heat along twenty-four hours as well as seasonal profile of
demand has an essential influence on size and configuration of cogeneration unit.

It should be stressed, that small scale distributed power generation units are
in fact not competitors against large scale power plants. Moreover, are desir-
able supplement of electricity grid increasing the flexibility of grid operation. In
industrial applications, the small scale CHP unit can cover electricity and heat
demands for specific technological process. In that case CHP unit operates as
a peak source of electricity.

All these mentioned reasons should stimulate development of small scale co-
generation systems. We should remember however, that the final decision for
investment and specific CHP unit configuration should be result of technical and
financial analysis.

2 Conditions of cost-effectiveness of cogeneration
     projects

Even the most beneficial technical indices of energy conversion and emissions
are not crucial points to realize investment project of CHP unit. The most
important premise is here positive economical effect. The measure of economical
effectiveness (for example net present value (NPV), internal rate of return (IRR)
etc.) depends on a great deal of factors. The most important of them are:

• time variation of power and heat demand,
• prices of fuel, electricity, heat and certificates of origin,
• structure of CHP system and technical parameters: power level, efficiency (heat rate), power-to-heat ratio, exploitation characteristics,
• operation mode of CHP.

The most promising effects are achieved for optimally selected technical and economical circumstances.

According to the being if force standards the measure of economical effectiveness are discounted indices of the cost-effectiveness: net present value (NPV), internal rate of return (IRR) and payback period (DPB). The project is profitable if positive financial effect is achieved, i.e., NPV > 0. Moreover the payback period DPB and internal rate of return IRR should satisfy expectation of investor. Eventually the economical effectiveness of CHP project depends on great deal of factors, which can be classified into two groups:

a) Technical and exploitation factors (microeconomical):
- efficiency of power and heat generation (relatively high for gas fired units),
- annual level of utilization of nominal power and heat load,
- unitary investment cost of gas fired CHP units (lower than for other power generation technologies),
- time of start-up of CHP unit (very short for gas fired units: gas turbines and IC engines);
- possibility of optimal sizing of nominal power of the unit,
- environmental impact (low for gas fired units),
- site demand (very low for gas fired units).

b) Macroeconomic factors:
- the cost of investment capital (value of the rate of discount),
- cost of fuel (i.e., cost of natural gas),
- electricity prices (level and daily/annual variations),
- heat prices,
- prices of certificates of origin for electricity generation in high-efficient cogeneration (‘yellow’, ‘violet’ and ‘red’ certificates),
- prices of certificates of origin for electricity generation base on the renewable primary energy sources (‘green’ certificates),
• costs of emissions to the environment (including cost of commissions for CO₂ emission).

Several relationships among technical/operational factors can be derived. These relationships allows us to optimally select the structure of the power generation system on the level of feasibility study analysis. Conclusions from that analysis can be very useful for technical optimization of the system and its exploitation conditions.

As a measure of economical effectiveness of the investment project one can assume net present value:

\[ \text{NPV} = \sum_{t=0}^{N} \frac{CF_t}{(1 + r)^t}, \]

where \( CF_t \) is the annual cash flow, \( t \) is the number of the year of exploitation (year of number zero represents total investment cost), \( r \) is the rate of discount for the project, and \( N \) is the period of exploitation (in years).

The project is cost-effective only when vale on \( \text{NPV} \) is greater than zero for \( N \) years of exploitation (\( \text{NPV} > 0 \)). If we assume that value of cash flow \( CF_t \) in successive years of exploitation are constant or similar, condition of cost-effectiveness of the project can be written as

\[ CF_t > 0. \]

Cash flow consists of several items:

\[ CF_t \equiv S - K - P = S - K - p(S - K - A - F), \]

where \( S \) – total annual income, \( K \) – total annual exploitation cost, \( A \) – annual rate of depreciation, \( P \) – income tax, \( p \) – the rate of income tax (e.g., \( p = 19\% \)), \( F \) – financial costs (e.g., rate of interest). Taking into account that income tax \( P \) is always lower then difference between incomes \( S \) and costs \( K \) we can assume that condition \( CF_t \) can be fulfilled only when total income \( S \) is greater than total cost \( K \):

\[ \Delta S - K = S - K > 0 \quad \text{or} \quad \zeta_{S-K} = \frac{S}{K} > 1 \Rightarrow \text{max}. \]

Financial streams of income \( S \) and cost \( K \) include great number of elements, but in practice (especially for projects in energy conversion area) significant influence have only several of them. In the case of gas fired CHP system those are:

a) Incomes \( S \):
• sale of electricity (or avoided purchase), $S_{el}$,
• sale of heat, $S_Q$,
• sale of certificates of origin for electricity generation in high-efficient cogeneration (‘yellow’, ‘violet’ and ‘red’ certificates) and prices of certificates of origin for electricity generation base on renewable primary energy sources (‘green’ certificates), $S_{co}$.

b) Costs $K$:

• cost of fuel, $K_f$,
• purchase of certificates of origin for electricity generation in high-efficient cogeneration (‘yellow’, ‘violet’ and ‘red’ certificates) and prices of certificates of origin for electricity generation base on renewable primary energy sources (‘green’ certificates),
• rate of depreciation, $K_d$,
• excise tax for sale of electricity, $K_{et}$ (paid by supplier of electricity to enduser).

For the most common in practice gas fired CHP systems, i.e., fired by natural gas, the crucial influence on the cost-effectiveness of the project have only few (exactly four) items: $S_{el}, S_Q, S_{co}$ and $K_f$.

Sale of electricity generate an income

$$S_{el} = E_{els} c_{el}$$ \hspace{1cm} (5)

where $E_{els}$ is an amount of electricity being sold, and $c_{el}$ is an average unitary price of electricity.

Sale of heat generate an income

$$S_Q = Q c_Q$$ \hspace{1cm} (6)

where $Q$ is an amount of heat being sold, and $c_Q$ is an average unitary price of heat.

Relationship between amount of electricity $E_{els}$ and amount of heat $Q$ defines exploitation (real) power-to-heat rate

$$\sigma = \frac{E_{els}}{Q}$$ \hspace{1cm} (7)

hence

$$S_Q = \frac{E_{els}}{\sigma} c_Q$$ \hspace{1cm} (8)
Sale of certificates of origin generates an income

\[ S_{sc} = E_{el,CHP}c_{sc} \tag{9} \]

where \( E_{el,CHP} \) [MWh] is an amount of electricity which can be classified as being generated in high-efficient cogeneration.

In Poland an amount of electricity which can be classified as being generated in high-efficient cogeneration results from general formula [3,4]:

\[ E_{el,CHP} = \beta E_{el} \tag{10} \]

where \( E_{el} \) denotes total (gross) amount of electricity produced in CHP unit. The value of parameter \( \beta \) can vary from 0 to 1. Specific value of \( \beta \) depends mainly on total efficiency of CHP unit \( \eta_{CHP} \) and coefficient of primary energy savings (PES). It is required [4] to comply the conditions PES > 10\% or PES > 0 to obtain the certificates of origin from generation of electricity in high-efficient cogeneration. If coefficient PES satisfy mentioned conditions, value of parameter \( \beta \) depends mainly on value of total efficiency of CHP unit

\[ \eta_{CHP} = \frac{E_{el} + Q}{E_{chf}} = \frac{E_{el} + E_{el}/\sigma}{E_{chf}} \tag{11} \]

where \( E_{chf} \) is the consumption of chemical energy of fuel in CHP unit, and \( Q \) is the amount of heat supplied to endusers.

Main element of exploitation costs of CHP unit fired by natural gas is the cost of fuel

\[ K_{chf} = E_{chf}c_{chf} \tag{12} \]

where \( c_{chf} \) is the unitary cost of chemical energy of fuel (e.g., PLN/GJ). An amount of chemical energy of fuel \( E_{chf} \) and amount (gross) of electricity \( E_{el} \) define very important technical parameter of CHP module, i.e., electric efficiency,

\[ \eta_{el} = \frac{E_{el}}{E_{chf}} \tag{13} \]

An amount of electricity which is sold from CHP \( E_{els} \) is always smaller than amount of electricity produced by CHP \( E_{el} \) because the part of electricity should cover own needs of CHP unit

\[ E_{els} = (1 - \varepsilon_{w})E_{el} \tag{14} \]

where parameter \( \varepsilon_{w} \) usually cover the value from 0.03 to 0.07.

When analyzing relationships defining specific elements of cash flow it is possible to separate those parameters, which have the most important influence on the cost-effectiveness of gas fired cogeneration unit:
a) Technical parameter:
   • efficiency of power generation, \( \eta_{el} \)

b) Operational parameter:
   • real (operational) power-to-heat ratio, \( \sigma \)

c) Price parameters:
   • the price of chemical energy of fuel, \( c_{chf} \)
   • price of electricity (sale or avoided purchase), \( c_{el} \)
   • price of certificate of origin \( c_{co} \).

It would be very difficult to derive even estimate, but general, relationships which could show the influence of above mentioned parameters on cost-effectiveness of the cogeneration project (the large number of statistical data should be considered). It is however possible when analyzing smaller groups of similar project (in the sense of technical and macroeconomics circumstances). Results of such an analysis for small scale cogeneration project is shown in the next chapter. CHP unit is fired by natural gas or coal bed methane.

3 Analysis of sample small-scale cogeneration project

Analysis of the influence of most important technical, operational and financial parameters on the cost-effectiveness of cogeneration project has been carried out on the sample of the small scale CHP unit (about 6 MW of thermal load) with IC engine (Fig. 1) or gas turbine (Fig. 2). Main technical differences between these two devices are: efficiency of power generation and nominal heat-to-electricity ratio (Tab. 1). CHP system produces electricity and hot water for heating purposes. Electricity is being sold to enduser (via separate electric cable) when hot water is being sold to the local heating network. Hot water covers heat demand according to given heat load duration profile (Fig. 3). CHP system is supplied by gas fired boiler to cover peak heat demand. Maximum heat demand is on the level of 9.5 MW\(_{Th}\). It is assumed that CHP covers heat demand at the base of load, i.e., about 6 MW\(_{Th}\). Higher heat loads are covered by gas fired water boiler.

As it was mentioned CHP unit can be fired by two different fuels of radically different prices:
Figure 1. Scheme of CHP unit with IC reciprocating engine.

Figure 2. Scheme of CHP unit with gas turbine.
a) natural gas (unitary price $c_{ch,f} = 40$ PLN/GJ),

b) coal bed methane (unitary price $c_{ch,f} = 5$ PLN/GJ).

From the cost-effectiveness point of view difference in the unitary price has an crucial meaning: price of coal bed methane is 8 times lower, what means lower share of fuel cost within total exploitation cost.

To provide reliable comparison of cost-effectiveness of CHP projects it has been assumed, that selection of technical parameters of IC engine and gas turbine results from matching in the heat demand side. It means (Fig. 3), that nominal heat load of IC engine and gas turbine lies in the range 6–7 MW\(_{Th}\). Specific technical parameters of selected (from producers offers) machines are presented in Tab. 1. We can see, that for comparable nominal heat loads IC engine represents much more higher electrical efficiency as well as nominal power-to-heat ratio.

<table>
<thead>
<tr>
<th></th>
<th>IC gas engine (2 pieces)</th>
<th>Gas turbine</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nominal heat load(^c), MW(_{Th})</td>
<td>6.09</td>
<td>6.76</td>
</tr>
<tr>
<td>Nominal electric power, MW(_{el})</td>
<td>6.71</td>
<td>3.52</td>
</tr>
<tr>
<td>Electrical efficiency, %</td>
<td>44.9</td>
<td>27.9</td>
</tr>
<tr>
<td>Nominal power to heat ratio $\sigma_{nom}$</td>
<td>1.1</td>
<td>0.52</td>
</tr>
</tbody>
</table>

* Flue gases are cooled to 120 \(^\circ\)C

Annual operational technical parameters of CHP systems have been calculated on the base of technical data of machines and heat load duration profile (see Tab. 2). Annual operation time is assumed 8500 h.

From analysis of data presented in Tab. 2 we can derive several important conclusions according to technical operational parameters of the CHP system:

- CHP with gas turbine provides much lower nominal and operational power-to-heat ratio (it results mainly from relatively low electric efficiency of gas turbine).
- Level of utilization of nominal heat load from the modules with IC engine and gas turbine is similar.
- Total efficiency of CHP module with IC engine is much more higher (for similar heat load IC engine produces much more electricity).
- Coefficient of Primary Energy Savings PES for CHP system with gas turbine is equal to 8.3\% (is lower than 10\% limit). It means that in spite of
relatively high total efficiency it is impossible to get certificates of origin for the electricity produced in high efficient cogeneration.

- An amount of fuel fired in water peak boilers is very small (on the level of 1%).

As the next step the prefeasibility study of cost-effectiveness of the CHP projects has been derived. Four case studies was analyzed: (IC engine, gas turbine, natural gas, coal bed methane) to calculate cost-effectiveness indices (NPV, NPVR, IRR,
DPB). Following assumptions and values were taken into analysis (prices without VAT tax):

- discount rate: 8.9%,
- exploitation time: 12 years,
- price of natural gas (average): 40 PLN/GJ,
- price of coal bed methane (average): 5 PLN/GJ,
- price of electricity (sale to enduser, average): 295 PLN/MWh,
- price of heat (average): 35 PLN/GJ,
- price of certificate of origin ‘yellow’: 128 PLN/MWh,
- price of certificate of origin ‘violet’: 55 PLN/MWh.

The results of calculations of cost-effectiveness indices are presented in Tab. 3. Shares of the most important cash flow items (incomes and costs) are shown in Tab. 4. To simplify the analysis it was assumed, that depreciation charges are constant for each year of exploitation time.

### Table 3. Cost-effectiveness indices for CHP projects.

<table>
<thead>
<tr>
<th></th>
<th>Natural gas</th>
<th>Coal bed methane</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>IC engine</td>
<td>Gas turbine</td>
</tr>
<tr>
<td>Total investment cost CNI million PLN</td>
<td>19.2</td>
<td>14.0</td>
</tr>
<tr>
<td>NPV million PLN</td>
<td>8.300</td>
<td>-53.8</td>
</tr>
<tr>
<td>NPVR=NPV/CNI PLN/PLN</td>
<td>0.432</td>
<td>-3.9</td>
</tr>
<tr>
<td>DPB years</td>
<td>8</td>
<td>-</td>
</tr>
<tr>
<td>IRR %</td>
<td>16.3</td>
<td>-</td>
</tr>
</tbody>
</table>

Results in Tabs. 3 and 4 show, that for CHP which is fired by relatively expensive fuel (natural gas) cost-effectiveness is positive (but barely) only for the system with IC engine. CHP with gas turbine is not profitable. It results mainly due to the low electrical efficiency of the gas turbine together with high share of fuel cost (absolute and relative). Even for CHP system with IC engine the ratio of annual incomes to annual costs is only slightly greater than unity, so the cost-effectiveness indices are very sensitive to the even very small changes of prices and exploitation parameters. Cost-effectiveness of the project considerably improves for coal bed methane fired CHP systems. Cost of fuel is here much more lower. For the same incomes we have nearly twice smaller costs (the share of fuel cost
Table 4. Share of main streams of annual incomes and costs.

<table>
<thead>
<tr>
<th></th>
<th>Natural gas</th>
<th>Coal bed methane</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>IC engine</td>
<td>Gas turbine</td>
</tr>
<tr>
<td><strong>Incomes (annual, net)</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sell of electricity to enduser, %</td>
<td>62.3</td>
<td>70.3</td>
</tr>
<tr>
<td>Sell of heat, %</td>
<td>15.3</td>
<td>25.7</td>
</tr>
<tr>
<td>Sell of certificates of origin (‘yellow’ for natural gas and ‘violet’ for coal bed methane), %</td>
<td>22.4</td>
<td>0.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>100.0</td>
<td>100.0</td>
</tr>
<tr>
<td><strong>Costs (annual, net)</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost of fuel for CHP module, %</td>
<td>76.8</td>
<td>81.6</td>
</tr>
<tr>
<td>Cost of fuel for water boiler, %</td>
<td>0.8</td>
<td>0.8</td>
</tr>
<tr>
<td>Cost of purchase of ‘green’ certificates of origin, %</td>
<td>6.1</td>
<td>4.1</td>
</tr>
<tr>
<td>Annual depreciation charge, %</td>
<td>6.7</td>
<td>5.3</td>
</tr>
<tr>
<td>Excise tax for electricity, %</td>
<td>4.6</td>
<td>3.0</td>
</tr>
<tr>
<td>Operation and maintenance costs (inspections, repairs, overhaul, oil, filters etc.), %</td>
<td>1.4</td>
<td>1.1</td>
</tr>
<tr>
<td>Cost of wages, %</td>
<td>1.2</td>
<td>1.5</td>
</tr>
<tr>
<td>Cost of certificates of origin (‘green’, ‘yellow’, ‘red’ and ‘violet’), %</td>
<td>2.2</td>
<td>1.5</td>
</tr>
<tr>
<td>Cost of emission (without cost of commissions for CO$_2$ emission), %</td>
<td>0.2</td>
<td>0.3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>100.0</td>
<td>100.0</td>
</tr>
<tr>
<td><strong>Ratio incomes/costs</strong></td>
<td>1.18</td>
<td>0.65</td>
</tr>
</tbody>
</table>

in total cost is here on the level only 30–35%). As the result even for the CHP system with gas turbine one achieves very profitable cost-effectiveness indices (as for projects in power generation area). From the structure of incomes results, that for all analyzed cases the most important share has the sell of electricity and the sell of certificates of origin for the electricity from high-efficient cogeneration (from 68 to 85% of total income).

4 Conclusions

Several conclusions can be derived from presented analysis according to the technical and economical circumstances of small scale cogeneration projects in Poland in distributed power generation area:

- Electrical efficiency $\eta_{el}$ of CHP module is the basic technical parameter which influences cost-effectiveness of the project.
• Real electricity-to-heat ratio $\sigma$ is the basic operational parameter which influences cost-effectiveness of the project.

• Price of chemical energy of fuel $c_{chf}$, price of electricity $c_{el}$ (sell or avoided purchase) and price of certificates of origin $c_{co}$ (sell and possible purchase) are the basic financial parameters which influence cost-effectiveness of the project.

• Cost of electricity is the most important parameter to obtain positive cost-effectiveness indices for the CHP systems fired by natural gas (expensive fuel). Hence it is purposeful to built CHP units which supply electricity directly to endusers or which cover own needs (avoided purchase of electricity).

• For CHP units fired by cheap fuel (e.g., coal bed methane) it is possible to obtain positive cost-effectiveness indices even for low electrical efficiency of the CHP module and low real electricity-to-heat ratios.

Received in June 2012

References


Analiza uwarunkowań techniczno-ekonomicznych budowy gazowych układów kogeneracyjnych małej mocy w Polsce

**Streszczenie**

Przeprowadzono ocenę wpływu wybranych parametrów technicznych, eksploatacyjnych i cenowych na wskaźniki opłacalności budowy gazowych układów kogeneracyjnych małej mocy w Polsce. Określono wpływ sprawności elektrycznej modułu kogeneracyjnego (CHP – *combined heat and power*) i eksploatacyjnego wskaźnika skojarzenia na podstawowe składniki kosztów i przychodów z eksploatacji układu. Przeprowadzono analizę obliczeniową układu kogeneracyjnego z gazowym silnikiem tłokowym lub turbiną gazową zasilanych gazem ziemnym systemowym lub gazem z odmetanowania kopalni.
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Jarosław Milewski*

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Institute of Heat Engineering
Warszawa

Thermodynamic analysis of compressed air energy storage working conditions

The compressed air energy storage (CAES) technology and electricity generation by this system are described. General performances and possible system efficiency definitions of those kinds of systems are indicated. Hybrid systems which consist of CAES and other renewable technologies (RT), e.g., wind turbines, are presented. A possibility of CAES-RT location in Poland is indicated. Dynamic mathematical model of CAES is presented; using this model the results for compressing and expanding operating modes are obtained.

1 Introduction

For obvious reasons the energy load on the grid is variable in time. There are both short-term variations within a day and long-time variations of seasonal character. The variability of load is further increased with connection of the sources characterized by low reliability. Sometimes it poses a significant risk of high output changes resulting from factors independent from the load changes. This applies primarily to wind turbines and also solar power stations.

One of the methods of supplying peak-load energy is to use various forms of energy accumulation. Classic solutions involving such accumulation capabilities are:

- pumped-storage power plants;
- compressed air energy storage (CAES) power plants, which use decompression of air stored in underground accumulators (reservoirs).

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The latter technology has been introduced quite a long time ago (Huntorf Power Station of 280 MW, Germany 1978 [1,2].) Until now one more large installation of this type has been commissioned (Mc Intosh, 110 MW, USA, 1991); there are several experimental plants as well. There is also a number of plans for such projects even of very high outputs (the largest being the Electric Power Generating Facility in Norton, total plans for 2700 MW based on CAES units with 300 MW turbines), however their construction is still being delayed. Bearing in mind the future of the renewable energy sources, it is interesting how these can cooperate with CAES plants – such projects are described further: CAES plant in the world, realized and planed:

- Huntorf, Germany – the first commercial CAES (290 MW)
- Mc Intosh, USA (110 MW)
- Norton, USA (finally is planed 2700 MW) – declared in the literature to be built in phases, in 2010 the project has been sold to a big energy company – First Energy – construction is to be launched in 2011
- Markham, Texas, USA (4×135 MW = 540 MW)
- Dallas Center, Iowa, USA (cooperation with wind turbines was planned – finally project is terminated because of inadequate geological conditions in-situ)
- Sestra, Italy (25 MW) – experimental power plant in which air is stored in aquifer, probably not involved any more
- Vianden, Luxemburg (285 MW)
- Ll. Torup, Denmark
- Some data can be found for: Japan (35 MW), Israel (3×100 MW = 300 MW – Israel Electric Company), Russia (1050 MW), Korea (300 MW), and Morocco (400 MW)

In Poland there are convenient locations for the construction of CAES. Knowledge of this technology is not widespread (virtually none.) Additionally, there is very lack responce from the power industry.

A working concept of a CAES power station is presented in Fig. 1. More complex configurations of such installations are described for instance in [3,4]. Compressed air can be used for smaller application in similar way [5]. This type
of plant consumes cheap electricity – available while the load on the grid is lower – for instance at nights and during weekends. This power is used to compress the air inside the great containers. Accumulation of the compressed air is based on experience – also Polish – with the underground natural gas storage, which trace 60 years back. Due to huge volumes of required air and resulting financial restrictions currently it is only economically feasible to use natural reservoirs. They can be for instance salt caverns, aquifers and excavations in salt, limestone and other mines created within the hard rock structure.

Due to a volume of storage spaces, even those large, the storage pressure must be relatively high. The maximum value should be considerably higher than the required level for the installed combustion chamber within the gas turbine unit. The minimum value in the storage cycle should also exceed the level required for the combustion chamber. The generation is started up when the demand for electricity is high. The air is discharged from the accumulating space and decompressed in the turbine. Due to high compression ratio of the compressor, resulting from the requirements mentioned above, it is necessary to use intercooling in such a plant (which is not marked in Fig. 1). Additionally it is required to keep appropriately low temperature of the air fed into the storage (inter-coolers and an after-cooler after the last stage of the compressor).

An advantage of the CAES concept is the fact, that – as opposed to the situation when the fuel gas is stored – the gas turbine can work independently during the decomposition process. Thanks to that the power transmitted to the generator is not limited by the necessity to drive the compressor at the same time. In the power balance of a classic large gas turbine unit (compressor-combustion
chamber-turbine) the compressor drive requires more than 50% of the power generated in the turbine. Separation of the compression and decompression in time allows the turbine to deliver much higher output than required to drive the compressor in the classic scheme. Ability to carry out the compression process in longer period allows to further increase the difference in power consumed (by the compressor) and delivered (by the turbine).

The CAES systems should not be treated as a ‘pure’ method of storing the energy, as they consume fuel supplied to the gas turbine unit. In this situation they should rather be considered hybrid systems used both for generation and storage of energy. Their significant features are ability of quick ramp-up and favorable ratio between the power output and power demand for compression. The air from the storage can be decompressed without any fuel input, but the energy effect in this case is relatively smaller, and the output air temperature lower than the ambient temperature. The air fed into the turbine can be warmed up in a heat exchanger (Fig. 1), by the heat recovered from the exhaust gas and then used in the combustion chamber. Additional option is to use the energy recovered in the cooling process before feeding the air into the cavern.

Figure 2. Scheme of the Iowa Stored Energy Plant, which illustrates the rules of cooperation with external objects, including a wind farm and underground gas and air storage [6].
2 CAES plants cooperating with RES, including wind turbines

One such installation was planned near Fort Dodge, Iowa (USA). It is planned to use an aquifer to store the compressed air there. A distinctive feature of this project is a plan to simultaneously store the natural gas in a similar way (Fig. 3). It is considered to store the gas and air in the same or (alternatively) various geological layers. Both possibilities have been identified at the planned site. It is considered to use the existing natural gas deposits as a ‘cushion’ to store the gas fed from the grid. This project is now in the phase of study works, cofinanced from the public money (Department of Energy). Similar projects were also considered in Europe (for instance L1.Torup in Denmark). Generally they would allow to store the energy generated by the Renewable Technologies, which as a rule work in irregular cycles, and use it to cover peaking load and provide daily balancing – or, if larger storage would be available, also for long-term balancing. The concept of CAES-wind farm cooperation is also discussed in [2].

The Europe is currently one of the world’s leading regions in development of wind power. This fast growth can be illustrated by the increase of the installed output of wind farms from 1600 MW in 1994 to approximately 48 GW in 2006. Against this background the wind power installed in Poland (280 MW in October 2007) seems very small, but there is significant interest in new projects. In Poland there are also possible sites allowing to construct CAES plants. Construction of such an installation could prove particularly interesting now – bearing in mind current conditions. For some time, due to rapid growth of the power demand, especially in the northern part of the national grid, some threats for the power supply security are indicated.

It is considered a primary solution for the mentioned problem to use peaking-load gas turbines. However a CAES plant has some advantages when compared
to the classic gas turbine solution. It could accumulate the energy generated by renewable technologies and feed it to the grid during the high-load period. It also has a lower demand for the fuel gas when compared to the power output (which stands for smaller gas connection needed). Primary difficulties are: finding appropriate site and potentially long construction time, affected by the necessity of preparing the reservoir for the accumulation work and delivery of equipment – at least partially nonstandard and custom-designed.

3 Key features of the CAES plant

Technology of the compressed air energy storage plant is based on well-known solutions, which have been tested either in power industry or in gas industry. Those solutions are also well-known in Poland, at least on the operational level. Gas turbines used by the CAES solutions are based on adapted standard power solutions (extended with necessary elements). Compressor systems are based on solutions used in power installations (axial compressors) supplemented by elements tested in long-term operation in other branches of industry (centrifugal high-pressure air compressors).

Most studies on energy storage consider the CAES technology as the only alternative to the pumped-storage stations for the large power installations. The start-up time for a pumped-storage plant in the turbine mode is counted in minutes (from 1 to approximately 15). Start-up time of a CAES plant up to full load is two to three times shorter than the average for the classic gas turbine and is no higher than some 10 min.

<table>
<thead>
<tr>
<th>Element</th>
<th>Rock storage</th>
<th>Salt cavern</th>
<th>Aquifer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Plant without the storage, $/kW</td>
<td>440</td>
<td>430</td>
<td>410</td>
</tr>
<tr>
<td>Storage, $/kWh</td>
<td>30</td>
<td>1</td>
<td>8</td>
</tr>
<tr>
<td>Storage time, h</td>
<td>10</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>Total cost, $/kW</td>
<td>740</td>
<td>440</td>
<td>490</td>
</tr>
</tbody>
</table>

The estimated data (for year 2000) presented in Tab. 1 (according to [7,8]) the expected cost of constructing a CAES plant is noticeably higher than for the classic gas turbine plant, but significantly lower (at least two times [4]) than for pumped-storage plants. Cost of a CAES plant stated in Tab. 1 can be considered comparable to expected in Polish conditions, where appropriate locations of underground storage suitable for air storage can be expected for instance in the
area of Lower Silesia or Kuyavia. Constructing a CAES plant in Polish conditions could prove particularly attractive in coastal area, where it could cooperate with large off-shore wind farms.

The literature mentions two methods of underground air storage used in practice: constant pressure and constant volume. Alternative names for those solutions are wet and dry storage or air storage with and without compensation. In the constant volume technology the accumulator operates in the determined pressure range. The top pressure is defined by the geological conditions, primarily in reference to keeping leak proofness (determined by allowed air losses) during operation. The bottom pressure is defined by the allowed operational parameters of the plant’s machinery fed from the accumulator. The accumulator’s volume and mentioned pressures define the possible storage capacity.

4 Thermodynamic performance analysis

Comparison of different CAES plant variants can be done using the energy conversion efficiency defined as

$$\eta_{CAESc} = \frac{E_{elg}}{E_{ele} + Q_f},$$

where $E_{elg}$ and $E_{ele}$ are electrical energy fed to the grid and consumed (to drive the compressor) by the CAES plant, respectively, $Q_f$ is the chemical energy contained in supplied fuel.

Using the energy values (not power) is necessary to analyze the quality of energy conversion in the CAES system, because of different times of consuming and supplying electricity to the grid and different power values. The process parameters are variable in time, among them compressor capacity, dependent on the accumulator feeding pressure (if it is variable). The conditions inside the reservoir and process management (throttling, skid parameters, compressor stall limitations etc.) affect the time and regime of charging and discharging the accumulator. To determine those regimes it is necessary to construct appropriate dynamic model of the plant.

Using the efficiency definition (1) is not always convenient. We need to add up two different kinds of energy: electricity delivered by the grid and chemical energy supplied with the fuel. From this point of view it would be more appropriate to use the equation which includes the efficiency of electricity generation for the compression consumption.
\[ \eta_{CAES} = \frac{E_{elg}}{E_{ele} \eta_{elR} \eta_{elT}} + Q_f, \]  

where \( \eta_{elR} \) is the electrical efficiency of a reference base load power station and \( \eta_{elT} \) is the efficiency of electricity transmission to the CAES plant. This method is an attempt to evaluate the consumption of the fuel energy necessary to generate whole electricity delivered from the CAES plant. In order to avoid necessity to add up two different kinds of energy (electricity and chemical energy) the efficiency of a CAES plant can be also defined as

\[ \eta_{CAESf} = \frac{E_{elg} - E_{ele}}{Q_f}. \]

Considering the CAES technological process as a form of power generation based on delivered fuel. The efficiency defined in this way describes the effectiveness of fuel consumption in generation of net power output of the plant. It has to be emphasized, that the Eq. (3) can result in negative result (when \( E_{ele} > E_{elg} \)) or infinity (if \( Q_f = 0 \)).

There is one more way to describe the efficiency of a CAES plant, used for instance in [9]. It is the net electrical storage efficiency, defined as the ratio of the electrical energy delivered to the grid over the energy supplied with the natural gas

\[ \eta_s = 1 - \frac{(HR \eta_{gas})}{ER_{net}}, \]

where \( HR \) is the gas turbine’s heat rate, \( \eta_{gas} \) is the chemical energy to electricity conversion efficiency, and \( ER_{net} \) is the net supplied-received energy ratio. The result achieved from the Eq. (4) is sometimes given in balance sheets and compared to the efficiency of pumped-storage plants. For obvious reasons such a comparison is not unambiguous (see Fig. 11).

The process of charging and discharging the accumulator can be analysed with a mass and energy balances for the working medium (here transformed into the enthalpy balance):

\[ \frac{dm}{dt} = \frac{d(\rho V)}{dt} = m_\alpha - m_\omega, \]

\[ \frac{dH}{dt} = \frac{d(\rho V h)}{dt} = m_\alpha h_\alpha - m_\omega h_\omega + \frac{dp}{dt} + Q, \]

where \( m \) is the mass flow, \( h \) and \( H \) are the enthalpy and total enthalpy, respectively, \( p \) is the pressure, \( Q \) is the exchanged heat, \( \rho \) is the density, \( V \) is the
volume, and $t$ is the time; $\alpha$ and $\omega$ indexes mark appropriate parameters on inlet and outlet from the modeled accumulator (reservoir). In the extended form these equations are sometimes transformed based on (not always explicit) ideal gas model assumed for the working medium. Because of high pressure and significant pressure differences in the process this is a significant simplification. The specific heat in the room temperature changes by some 18% in the pressure range from 1 to 100 bar, so also the isentropic exponent is variable.

Equations (5) and (6) should be analyzed separately for charging and discharging modes. The work (energy consumption) needed to compress the working medium in the charging process has to be determined. Analogically the work of the turbine expansion process can be calculated. The analysis has to take into account processes of cooling the working agent between the compressor stages and after the compressor as well as the work received from the turbine.

5 Results of charging and discharging simulations

The premises and calculation results obtained for a CAES plant model with air expansion (combustion chamber simulated as the air heater) are presented below. The model was created in the HYSYS software environment used as a tool to generate dynamic characteristics. The performance characteristics (including the efficiency defined according to formulas (2) and (3)) of the CAES plant for various operational parameters can be found in the study [10] or – for a bit different installation – in [11].

Main premises for calculations:

- Capacity of the air accumulator (cavern) – 300,000 m$^3$ – constant volume system
- Heat and air losses to the environment considered negligible
- compressor polytropic efficiency: 75%
- compressor power: 60 MW
- turbine polytropic efficiency: 75%
- nominal air flow through the turbine: 400 kg/s
- turbine outlet pressure: 1 bar
- working medium model (Peng Robinson equation of the state)
Individual elements constructed in the HYSYS software environment create a dynamic model of the compressor unit (Fig. 3) and turbine unit powered by the air from the same cavern (Fig. 4). The assumed nominal parameters of the turbine were:

- inlet pressure: 4 MPa
- outlet pressure: 0.1 MPa
- working medium (air) mass flow: 400 kg/s.

The calculation results presented below refer to the following selected cases:

- charging the cavern from the pressure of 1 bar (50 °C) to 70 bar in the system fitted with inter-cooler and after-cooler (50 °C/50 °C),
- discharging from 70 bar (50 °C) to 1 bar with additional heating the air to the temperature of 1100 °C and throttling the agent before the turbine to 40 bar.

The charts present characteristics of the compressor-cavern (Figs. 7, 8, 9) and cavern-turbine (Figs. 8, 9, 10) subsystems. Figure 5 illustrates the accumulation capacity of the cavern with respect to the stored energy and air mass, while Fig. 6 presents changes in time of the air flow into the cavern and increase in cavern pressure. The power consumption of the compressor, air temperatures after the HP part and temperatures of the stored air shows Fig. 7. Real operation of CAES plant is carried out within the narrower pressure range than investigated here. The bottom pressure is selected so the plant has a reserve air for possible emergency start-up. For instance Huntorf Power Station is operated within the
pressure range of 4.3–7 MPa. In extraordinary situations it is allowed to decrease the operational pressure to 2 MPa. Analysis of the impact of the bottom air pressure on the performance of the CAES plant was carried out in [10].
Figure 7. Air temperature after the compressor and in the cavern during the charging process from the 0.1 MPa to 7 MPa; compressor with a single-stage inter-cooler and after-cooler.

Figure 8. Mass of the air discharged from the cavern and the energy delivered in fuel during the discharging process from 7 MPa to the ambient pressure with the air heated to 1100 °C before the turbine.

The power output on the generator terminals, at the premises mentioned above, is 320 MW and can be attained for almost 7 h. After this period it decreases, so the half of the maximum output can be generated for next 5 h (Fig. 10). The turbine inlet pressure is kept at constant level of 4 MPa as long as
Figure 9. Mass flow of the air discharged from the cavern, cavern pressure and turbine inlet pressure during the discharging process from 7 MPa to the ambient pressure with the air heated to 1100 °C before the turbine.

Figure 10. Turbine power output, turbine inlet and outlet temperatures and cavern temperature during the discharging process from 7 MPa to the ambient pressure with the air heated to 1100 °C before the turbine.

the cavern pressure is higher. During the further stage of discharging the turbine inlet pressure decreases along with the cavern pressure (Fig. 9). The energy is produced by the turbine is at the cost of discharging the air accumulator and fuel gas combustion (Fig. 8.)
6 Conclusions

Introduction of the emission trading scheme for the greenhouse gases, primarily the carbon dioxide, increases price competitiveness of the power generated by renewable technologies (RT). Significant drawback of the RTs however is irregularity of their power output. Introduction of the storage capability in a cooperating CAES plant allows eliminating this disadvantage, and if the purely adiabatic method is used, it keeps the greenhouse gas emission at the zero level. Generated electricity becomes dispatchable and can be used to cover the peak load. If the additional organic fuel (for instance natural gas) combustion is used in the discharged air flow, the combined system of cooperating Renewable-CAES plant still displays emission levels much lower than a standard gas-fired plant. Full independence from the variability of renewable power generation is provided by introduction of supplementary supply of fuel gas to such a plant. Zero emission level could be achieved if this gas fuel was a renewable one (biogas). Such concepts are also considered.

In case of a plant using additional fossil fuel in Polish conditions it has to be pointed out, that due to formal regulations some (or all) green certificates for the CAES-generated electricity could be lost. This issue greatly influences the energy sales price. The authors have not analyzed this question in detail, though it is a crucial factor, which might decide the feasibility of a possible investment.

The CAES plant displays good characteristics for partial-load operations. This is its significant advantage over the classic gas turbine plants. It can also achieve very fast turbine load changes of several dozen percent in a minute. Those

![Sankey's diagram of energy flows during charging and discharging processes.](image)
Thermodynamic analysis of CAES working conditions 67

capabilities make the system suitable for the peaking operation in a role of a fast reserve, for grid stability services and reactive power compensation.

In Poland there are potential sites suitable to construct the compressed air energy storage plants, for instance salt caverns. Especially nowadays construction of such a plant might prove interesting, bearing in mind large investments in wind power – already started or planned in the imminent future, primarily in the northern part of the country.

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Analiza termodynamiczna pracy układu CAES

S t r e s z c z e n i e

Use of gas in distributed sources in extensive heating systems

The aim of an investigation was to examine the heat sources, which can be used as a supplement for providing the heat for the users at the ends of extensive heating networks. The research was based on the technical and economic analysis that also included ecological effects. The integral element of the research was a comparative analysis of such distributed heat sources and the current heating systems regarding their mutual competitiveness factors or supplementation.

1 Description of distributed sources conception in heat engineering

Electricity distributed generation is widely known [1]. It is currently popular and broadly discussed topic. Heat networks operate on quite similar principles as electric grids. Obviously, the scale and range of heat networks is much smaller than that of electric grids. The idea for large heating system is that many buildings are fed from the radial-annular network. The network is fed by the central source (or more than one source). In Poland, in case of more than one central source, the sources operate most frequently for so-called allocated heat supply areas.

The aim of this investigation was to examine economic feasibility of constructing distributed heat sources and/or small gas cogeneration sources cooperating with extensive heating systems. The paper presents alternative connection methods for the users at the ends of heating network. It often happens that this type of reception is accompanied by power shortage (not the heat) resulting from the
network hydraulic limitations. This fact implies significant investments in development of heating network in order to eliminate the limitations. The alternative is to additionally supply such recipients from the distributed heat sources as shown in Fig. 1. It means that the recipient may be supplied with heat from own source and from the heating network. The way of cooperation between the distributed source and heating network may differ greatly. Various variants of cooperation between the source and heating network securing the supply for the recipient and electricity generation will be presented in following parts of the paper.

2 Analysis and variant selection of distributed heat sources for application in extensive heating networks

In order to select the sources for distributed heat generation it is necessary to determine the significant features, which these sources should possess. On that account, the sources for distributed generation should:

- secure the possibility of remote control – personnel costs minimisation,
- be ‘environment friendly’ – proximity to residential buildings.

The condition of being environment friendly is fulfilled by the sources fed oil and gas. Realisation of environment friendly sources in coal technology is very difficult and expensive, if not impossible. Additionally, maintenance-free work
Use of gas in distributed sources...

in coal sources is practically impossible. Taking into account the gas and oil prices, it has been decided to analyse further only natural gas.

The possibility of employing various kinds of sources in distributed power systems is widely discussed. One of such possibilities are fuel cells [2,3]. Unfortunately, they have not yet widely applied. Currently the commonly used sources, which are fed by natural gas, are:

- water boilers – only heat supply,
- piston engines – heat and electricity,
- gas turbines – heat and electricity.

Using gas water boilers as a local distributed source is a real possibility. If one compares the proposed cogeneration sources, taking into account the fact that the analysis is pertained to small heat sources, the practice shows that piston engines are better suited for these types of sources, than gas turbines. It stems from better economic efficiency of piston engines. The additional argument for piston engines is a much higher noise level generated by gas turbines, which is quite significant in case of distributed sources.

Natural gas prices are regulated by the tariffs. The law imposes the necessity of dividing the prices and rates into permanent and changeable rates. On that account, the gas price depends on the time of peak power usage and the tariff group. In order to depict the differences, the variability of the average price of chemical energy contained in the fuel depending on the chosen tariff groups and the time of peak power usage are presented in Tab. 1. The majority of calculations are made for tariff rates W6A [4]. This tariff is for the order of gas energy in the range between 65 and 600 m$^3$/h. It gives, with the lower heating value of 36 MJ/m$^3$, the range of power in the fuel from 650 to 6000 kW.

3 Heat supply variants

It is assumed that the recipient may be supplied from a distributed source (piston engine or gas boiler) and/or from the heat network. The base demand may be satisfied by the peak source or by the heat network. In result, five variants for recipient supply were defined. Summary comparison of the variants is given in Tab. 2. It is assumed that the total heat demand of a recipient amounts to 1 MW. On that account, the way of meeting the heat demand by the network and distributed source was determined. The results are given in the diagrams 2–6. The summary values comparison is given in Tab. 3.
Table 1. The unit cost of chemical energy in gas fuels in PLN/GJ for gas GZ-50 [MJ/m³].

<table>
<thead>
<tr>
<th>Contracted power</th>
<th>Time of peak power usage</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>500</td>
</tr>
<tr>
<td>200</td>
<td>64.66</td>
</tr>
<tr>
<td>300</td>
<td>64.50</td>
</tr>
<tr>
<td>400</td>
<td>64.41</td>
</tr>
<tr>
<td>500</td>
<td>64.36</td>
</tr>
<tr>
<td>598</td>
<td>64.33</td>
</tr>
<tr>
<td>602</td>
<td>61.11</td>
</tr>
<tr>
<td>650</td>
<td>61.08</td>
</tr>
<tr>
<td>700</td>
<td>61.06</td>
</tr>
</tbody>
</table>

Table 2. Comparison of basic features of particular variants.

<table>
<thead>
<tr>
<th>No.</th>
<th>Variant’s symbol</th>
<th>Basic source description</th>
<th>Peak source description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>HN</td>
<td>The whole supply comes from the heat network</td>
<td>None</td>
</tr>
<tr>
<td>2</td>
<td>HN-GB</td>
<td>The heat network is the major supplier (40% of power)</td>
<td>60% of the ordered power is supplied from the peak boiler</td>
</tr>
<tr>
<td>3</td>
<td>GB-HN</td>
<td>The base heat demand is met from the gas boiler (40% of power)</td>
<td>Peak demand is met from the heat network</td>
</tr>
<tr>
<td>4</td>
<td>GE-HN</td>
<td>The base heat demand is met from the gas engine (18% of power)</td>
<td>Peak demand is met from the heat network</td>
</tr>
<tr>
<td>5</td>
<td>GE-GB</td>
<td>The base heat demand is met from the gas engine (18% of power)</td>
<td>Peak demand is met from the gas boiler</td>
</tr>
</tbody>
</table>

Table 3. Comparison of heat amount supplied by the particular sources in particular variants in GJ.

<table>
<thead>
<tr>
<th></th>
<th>Heat network</th>
<th>Gas engine</th>
<th>Gas boiler</th>
<th>Sum</th>
</tr>
</thead>
<tbody>
<tr>
<td>HN</td>
<td>10877</td>
<td>0</td>
<td>0</td>
<td>10877</td>
</tr>
<tr>
<td>HN-GB</td>
<td>8271</td>
<td>2606</td>
<td>0</td>
<td>10877</td>
</tr>
<tr>
<td>GB-HN</td>
<td>0</td>
<td>2366</td>
<td>8511</td>
<td>10877</td>
</tr>
<tr>
<td>GE-HN</td>
<td>6310</td>
<td>4567</td>
<td>0</td>
<td>10877</td>
</tr>
<tr>
<td>GE-GB</td>
<td>0</td>
<td>4567</td>
<td>6310</td>
<td>10877</td>
</tr>
</tbody>
</table>
4 Central source operational model

The systematic diagram of the operation of a central source was drawn basing on real data from several Polish plants. It was assumed that the unit has 100 MW
of power and that 60% of power is produced in cogeneration and 40% of peak power units (water boilers). The modelled demand for heating power from the central unit was presented in Fig. 7. Moreover, it was assumed that the source was fed with hard coal as most of combined heat and power (CHP) plants of the type.
5 Technical and economic analysis

5.1 General assumptions

The aim of the analysis is to determine whether application of changes proposed will lead to decrease of heat generation costs and, therefore, minimize the price of heat for end-users. The owners of the heat source and of the heating network may have the same owner or different ones. It was assumed that the owner of both the network and the source is one business entity. If, in such case, it will be possible to obtain profitability of the project, it will also be valid for separate ownership of the network and the source. The two owners will then divide the costs and profits and the project will decrease costs of heat for the end-users.

In the stage of calculations it was assumed that 100\% of funding was made from own capital. Another significant assumption is that construction of distributed sources will not cause the need to reduce the capital in the central source. Owing that it was assumed that fixed costs of generation will not be reduced. Only the variable costs will be limited and they were defined as 5\% of fuel costs.

5.2 Investment outlays

Each variant includes different investment outlays. The description of the investment that has to be made in case of all the variants was presented in Tab. 4. Values of the outlays for each variant were presented in detail in Tab. 5.
Table 4. Necessary investment for each variant for distributed and central sources by type.

<table>
<thead>
<tr>
<th>Variant</th>
<th>Construction of a gas connection for peak and base units</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Base source</td>
</tr>
<tr>
<td>HN</td>
<td>Connection to the building, construction of heating substation. Power of the connection and substation 1 MW</td>
</tr>
<tr>
<td>HN-GB</td>
<td>Connection to the building, construction of heating substation. Power of the connection and substation 400 kW</td>
</tr>
<tr>
<td>GB-HN</td>
<td>Construction of a gas boiler house of power 400 kW and gas connection</td>
</tr>
<tr>
<td>GE-HN</td>
<td>Construction of a cogeneration plant of heating power 180 kW and gas connection</td>
</tr>
<tr>
<td>GE-GB</td>
<td>Construction of a cogeneration plant of heating power 180 kW</td>
</tr>
</tbody>
</table>

Table 5. Investment needed in thousands of PLN.

<table>
<thead>
<tr>
<th>Variant</th>
<th>Heating network</th>
<th>Gas-supply network</th>
<th>Gas boiler</th>
<th>Piston engine</th>
<th>Heating substation</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>HN</td>
<td>186</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1350</td>
<td>1536</td>
</tr>
<tr>
<td>HN-GB</td>
<td>165</td>
<td>86</td>
<td>900</td>
<td>0</td>
<td>540</td>
<td>1691</td>
</tr>
<tr>
<td>GB-HN</td>
<td>172</td>
<td>82</td>
<td>600</td>
<td>0</td>
<td>810</td>
<td>1664</td>
</tr>
<tr>
<td>GE-HN</td>
<td>180</td>
<td>78</td>
<td>0</td>
<td>810</td>
<td>1107</td>
<td>2175</td>
</tr>
<tr>
<td>GE-GB</td>
<td>0</td>
<td>93</td>
<td>1230</td>
<td>810</td>
<td>0</td>
<td>2133</td>
</tr>
</tbody>
</table>

5.2.1 Costs and operational revenues

In order to determine the cash flows it is necessary to determine costs and operational revenues. Operational costs include:

- change of fuel consumption in the CHP plant,
- fuel consumption in the distributed source,
- maintenance and service costs for:
  - heating substation and boiler in the amount of 2% of yearly investment outlays,
  - gas engine in the amount of 5% of yearly investment outlays,
• change of CO₂ emission costs including:
  – change of CO₂ emissions in the CHP plant,
  – free-of-charge CO₂ allowances for heat and electricity generation,
  – emission of CO₂ from distributed source.

The revenues include the following:

• change in electricity generation,
• change of revenues resulting from red certificates trade,
• change of revenues resulting from yellow certificates trade.

5.2.2 Heat and electricity prices forecast

All the calculations were made for fixed prices. The only variations were considered for electricity and heat prices. Own forecasts were made for the purpose. The assumptions are based on the fact that electricity prices will be formed by the utility power plants and the heat prices by the heating stations. Another assumptions is that power plants will transfer 100% of allowances costs into electricity price and that heat plants will transfer 100% of allowances costs into heat price. Allowances costs include free-of-charge allowances for electricity and heat generation. Assuming fixed CO₂ emission allowances price at 15 EUR/Mg and that 100% of the costs will be transferred into heat and electricity generation, forecasts for electricity and heat prices were made and are presented in Fig. 8. In case of heat prices the ‘gas benchmark’ for free-of-charge allowances was included.

![Figure 8. Electricity and heat price forecast for calculations.](image-url)
5.2.3 Economic analysis

In order to compare all the variants the internal rate of return (IRR) value was chosen because it does not require defining the rate of discount [5]. The main disadvantage of the IRR value is that the cash flow can have only one change of sign (in other case the IRR value is not unambiguous). In the analysis values of different initial outlays will be compared. In order to determine the IRR, values of cash-flow in each year were determined. The results are presented in Tab. 6.

Table 6. Results of economic analysis.

<table>
<thead>
<tr>
<th>Variant</th>
<th>HN</th>
<th>HN-GB</th>
<th>GB-HN</th>
<th>GE-HN</th>
<th>GE-GB</th>
</tr>
</thead>
<tbody>
<tr>
<td>IRR [%]</td>
<td>13</td>
<td>-1</td>
<td>-</td>
<td>10</td>
<td>-2</td>
</tr>
</tbody>
</table>

From the presented variants it is conspicuous that the most profitable case is heating from a large CHP plant through a heating network. The second most profitable is base heating by a gas engine and peak heating by heating network. The variant, in which the base demand is covered by the heating network and only peak load is covered by a gas boiler is not profitable. Similarly not profitable is the case when the base demand is covered by a gas boiler and the peak one by the heat from the heating network.

6 Summary

The idea of supplying heat from the heating network and an additional heat or heat and power source in different configurations was presented in the paper. From the presented calculations it stems that the most attractive way is to supply the heat only from the heating network. The alternative using distributed source is application of a gas engine as the base source and the heating network as a peak one. Specific conditions like length of the gas connection to the connection to the heating network will influence the profitability of the project.

We also have to consider that application of distributed sources may significantly increase reliability of supplying the end-users. Currently the topic of supplying standards and the security of heat supplies is neglected but the safety of constant supply is a product and may be evaluated. Revenues from the reliability of supplies may increase the profitability of such solutions. Common use of such applications may also decrease the costs of modernization and development of heating network which may also increase the effectiveness of the solution.
The paper focuses only on the technical and economic analysis of supplying heat from distributed sources. It had the aim to determine the purposefulness of using distributed sources in heating systems. The next step should involve technical possibilities of cooperation of distributed heat sources with the heating network.

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References


Wykorzystanie gazu w źródłach rozproszonych w dużych systemach ciepłowniczych

Streszczenie

W pracy zaprezentowano rozważania dotyczące ekonomicznej celowości instalacji zastosowania źródeł rozproszonych w ciepłownictwie. Pomyśl zastosowania źródeł rozproszonych w ciepłownictwie podobny jest do tego obecnie szeroko dyskutowanego pomysłu źródeł rozproszonych do produkcji energii elektrycznej. Ze względu na obecne warunki ekonomiczne do rozważań wybrano źródła zasilane gazem ziemnym. Zaproponowano pięć sposobów zasilania odbiorców na końcach rozległych sieci ciepłowniczych. Dla przedstawionych wariantów wykonano analizy ekonomiczne, których wyniki przedstawiona w pracy.
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Piotr Musiał\textsuperscript{2}

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Gazoproyekt S.A.
Wrocław
\item[\textsuperscript{2}] Control Process S.A.
Kraków
\end{itemize}

**Systemowe magazyny gazu w Polsce**

Niniejszy artykuł porusza kwestie związane z podziemnym magazynowaniem gazu, w ujęciu ich systemowego wykorzystania. Przedstawia aktualną sytuację pojemności magazynowych w Polsce oraz prezentuje punkt widzenia autorów na dalszy rozwój systemowych pojemności magazynowych, w aspekcie pojawiających się zmian na rynku gazu związanych z rozwojem energetyki gazowej, liberalizacją rynku gazu i rozwojem wydobycia gazu z łupków.

1 **Wstęp**

Gwałtowny rozwój gazownictwa na przełomie XIX i XX wieku, przesyłanie gazu ziemnego na coraz większe odległości i do coraz większej liczby odbiorców, rosnąca różnorodność zapotrzebowania na gaz, a tym samym zwiększająca się nierównomierność rozboru gazu doprowadziły do konieczności podziemnego magazynowania gazu. Pierwsze podziemne magazyny gazu (PMG) powstały już w latach 1915–16 na kontynencie amerykańskim, gdzie te procesy następowaly naj szybciej. Były to magazyny w szczyprowych złożach gazu w Kanadzie, w Welland County – Othario oraz w USA w rejonie Nowego Jorku – PMG Zoar-Erie. Europa, gdzie gazownictwo rozwinęło się bardziej w oparciu o tzw. gaz świetlny produkowany gazowniach lokalizowanych bezpośrednim sąsiedztwie odbiorców i wyposażonych w zbiorniki gazu. Podziemne magazynowanie rozpoczęło się dopiero w drugiej połowie XX wieku. Za to możemy w tej części świata poszczycić się palmą pierwszeństwa — pierwszy podziemny magazyn gazu w Europie, to PMG Roztoki o pojemności czynnej 3 mln m$^3$, który powstał w roku 1954 [1].

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Coraz większe powiązanie polskiego systemu gazowniczego z systemem europejskim, budowa terminalu do odbioru skroplonego gazu (LNG, ang. *liquefied natural gas*) stanowiącego alternatywne źródło zaopatrzenia w gaz, a także dopuszczenie możliwości magazynowania gazu poza Polską, wymagają kreatywnej analizy i nowego spojrzenia problem dalszej rozbudowy pojemności magazynowych w Polsce. Aby na nie odpowiedzieć należy zastanowić się nad następującymi zagadnieniami:

- prognozą bilansu gazu i rozwoju systemu gazowniczego,
- funkcjami jakie pełni PMG, szczególnie w zakresie bezpieczeństwa dostaw,
- aktualną sytuacją PMG w Polsce,
- strategią i planowaniem rozbudowy PMG dla regulacji pracy systemu przesyłowego i tworzenia obowiązkowych zapasów,
- potencjalnych możliwości budowy pojemności strategicznych oraz euromagazynów.

2 Prognoza bilansu gazu i rozwoju systemu gazowniczego

Porównując prognozowane zapotrzebowanie na gaz (prognoza na podstawie Polityki Energetycznej Polski do 2030 roku [2]) a przewidywanymi dostawami gazu realizowanymi poprzez import do polskiego systemu gazowniczego (kontrakty ja-malski i katarski), poprzez węzeł Lasów i poprzez źródła krajowe (przewidywane wydobycie ze złóż krajowych z uwzględnieniem odazotowania gazu zaazotowanego), należy zauważyć narastający deficyt strony popytowej w ilości od 2,8 mld m³ w roku 2015 do 7,1 mld m³ w roku 2025, co przedstawiono na rys. 1. Deficyt ten będzie mógł być pokrywany poprzez nowe połączenia międzysystemowe z Czechami (w rejonie Cieszyna wybudowane w 2011 r.), Niemcami (w rejonie Szczecina), Słowacją (w trakcie analiz), rewers wirtualnym systemem gazociągów tranzytowych, zwiększenie wykorzystania terminalu LNG w Świnoujściu bądź też rozbudowę istniejących interkonекторów (Lasów, Cieszyn). Przynajmniej część z nich wykorzystywana będzie zamiennie, a dostawy realizowane będą w oparciu o kontrakty krótkoterminowe. Doprowadzenie tak zakontraktowanych dostaw gazu wymagać będzie istotnego zwiększenia możliwości przesyłowych systemu gazowniczego, z odpowiednią rezerwą przepustowości, a tym samym realizację znacznego zakresu inwestycyjnego. Najważniejszym podmiotem realizującym te działania jest Operator Systemu Przesyłowego Gaz System S.A., który program rozbudowy systemu przesyłowego obejmujący ok. 1000 km gazociągów rozpoczął
Rysunek 1. Prognoza zbilansowania dostaw gazu do system

Rysunek 2. Wymagana rozbudowa sieci przesyłowej
już kilka lat temu. Do tej pory zrealizowano m.in. połączenie polskiego i czeskiego systemu gazowniczego, gazociągi w południowo-zachodniej części kraju: Taczalin-Radakowice-Gałów i Jeleniów-Dziwiszów; w północnej Polsce: Włocławek-Gdynia (dokończenie inwestycji), Żeg-Żarnowiec, czy też tłoczni Goleniów i Jarosław. W przygotowaniu jest, albo już rozpoczęła się budowa wielu innych (rys. 2).

3 Podziemne magazyny gazu jako instrument bezpieczeństwa dostaw gazu

Instrumenty służące do zapewnienia bezpieczeństwa dostaw gazu zostały określone w Dyrektywie Rady Unii Europejskiej 2004/67/EC z dnia 24 kwietnia 2004 r., dotyczącej bezpieczeństwa dostaw gazu [3]. Dokument ten w wykazie dostępnych instrumentów na pierwszych miejscach wskazuje:

- możliwości składowania zapasów operacyjnych gazu,
- możliwości składowania nadwyżek gazu.


- zapewnienie bezpieczeństwa zaopatrzenia w gaz w perspektywie krótkoterminowej (zapasy handlowe), jak i długoterminowej (rezerwy strategiczne w dyspozycji Ministra Gospodarki),
- kompensacji sezonowej nierównomierności poboru,
- stabilizację cen gazu,
- zwiększenie i wyrównanie wydobycia ze złóż krajowych i zapewnienie stabilnych warunków pracy odzotwni (umożliwienie odbioru gazu produkowanego w okresie letnim),
- wsparcie przesyłu i ograniczenie potrzeb inwestycyjnych w zakresie sieci przesyłowej.
Stopień zapewnienia bezpieczeństwa dostaw gazu przez podziemne magazyny gazu można określić odnosząc wielkość roboczych pojemności magazynowych do rocznego zużycia gazu w danym kraju, a także przeliczając ilość zmagazynowanego gazu na ilość dni średniego poboru gazu jaka może zostać zapewniona przez PMG. Im wyższe są te wskaźniki, tym stopień bezpieczeństwa dostaw jest większy, chyba że niewielkie pojemności magazynowe są rekompensowane własnymi złożami (Holandia, Wielka Brytania) lub terminalami LNG (Hiszpania, Grecja, Belgia) – tab. 1.

Tabela 1. Pojemności magazynowe w wybranych krajach UE w 2000r.

<table>
<thead>
<tr>
<th>KRAJ</th>
<th>ZUŻYCIE</th>
<th>ROZCZE</th>
<th>DZIENNI</th>
<th>ROBOCZA</th>
<th>Udział w rocznym zużyciu (%)</th>
<th>Czas średniego poboru z PMG</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(mld m³)</td>
<td>(mld m³/ro)</td>
<td></td>
<td>(mld m³)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Austria</td>
<td>7,3</td>
<td>24,0</td>
<td>2,3</td>
<td>32,1</td>
<td>116</td>
<td></td>
</tr>
<tr>
<td>Dania</td>
<td>4,5</td>
<td>25,0</td>
<td>0,8</td>
<td>17,6</td>
<td>64</td>
<td></td>
</tr>
<tr>
<td>Francja</td>
<td>42,4</td>
<td>180,0</td>
<td>11,1</td>
<td>26,2</td>
<td>96</td>
<td></td>
</tr>
<tr>
<td>Niemcy</td>
<td>83,2</td>
<td>425,0</td>
<td>18,8</td>
<td>22,3</td>
<td>81</td>
<td></td>
</tr>
<tr>
<td>Włochy</td>
<td>68,6</td>
<td>265,0</td>
<td>15,1</td>
<td>22,0</td>
<td>80</td>
<td></td>
</tr>
<tr>
<td>Holandia</td>
<td>41,0</td>
<td>145,0</td>
<td>2,5</td>
<td>6,1</td>
<td>22</td>
<td></td>
</tr>
<tr>
<td>Hiszpania</td>
<td>18,2</td>
<td>8,0</td>
<td>1,0</td>
<td>5,5</td>
<td>20</td>
<td></td>
</tr>
<tr>
<td>Wielka Brytania</td>
<td>96,7</td>
<td>137,0</td>
<td>3,6</td>
<td>3,7</td>
<td>13</td>
<td></td>
</tr>
<tr>
<td>POLSKA</td>
<td>11,2</td>
<td>32,0</td>
<td>1,3</td>
<td>11,6</td>
<td>41</td>
<td></td>
</tr>
<tr>
<td>UE 15 + POLSKA</td>
<td>403,2</td>
<td>1265,0</td>
<td>57,0</td>
<td>14,1</td>
<td>45</td>
<td></td>
</tr>
</tbody>
</table>

4 Aktualna sytuacja PMG w Polsce

Od początku XXI wieku mamy do czynienia z rosnącym szczytowym zapotrzebowaniem na gaz (za wyjątkiem obniżenia zapotrzebowania w okresie kryzysu 2007–2008 r.) od ok. 4 mln nm³/d w roku 2000 do blisko 70 mln nm³/d w roku 2010 i ponad 72 nm³/d w roku 2011 (z uwzględnieniem wprowadzonych ograniczeń dla dużych odbiorów przemysłowych zapotrzebowanie wynosiło ponad 8 nm³/d) oraz stabilnym zapotrzebowaniem dolinowym (na poziomie ok.
17–20 nm³/d). Tak sytuacja powoduje występowanie wysokiego wskaźnika nierównomierności zużycia gazu (od 2,7 w 2000 r. do 3,4 w 2010 r.), definiowanego jako stosunek zużycia gazu w ciągu doby o maksymalnym zapotrzebowaniu do zużycia gazu w ciągu doby o minimalnym zapotrzebowaniu. Tendencje zmian wskaźnika przedstawiono na rys. 3.

Z drugiej strony należy zdawać sobie sprawę z uwarunkowań długoterminowych kontraktów na import gazu, dopuszczających maksymalnie kilkunastoprocentowe procentowe wahania wolumenu odbieranego do systemu gazu, które nie mają istotnego znaczenia w dostosowaniu dostaw do dużej nierównomierności zapotrzebowania na gaz oraz potrzeby zapewnienia stabilnego wydobyćcia, zapewniającego optymalne wykorzystanie złoż w źródłach krajowych. Najbardziej efektywnym instrumentem w tym zakresie wydają się być podziemne magazyny gazu – odbierające nadwyżki gazu zakontraktowanego i wydobywanego w kraju, w stosunku do zużywanego przez odbiorców w okresie letnim, natomiast w okresie zimowym stanowiącego uzupełniające źródło dostaw, pokrywające różnice pomiędzy zapotrzebowaniem na gaz przez odbiorców, a mocą dyspozycyjną dostępnych źródeł (kontrakty importowe i wydobycie krajowe). Proces ten zobowiązany na rys. 4. Zasadność wykorzystywania tego instrumentu dostrzegana jest we wszystkich krajach UE (tab. 2), gdzie w ostatnich latach następuje istotny, bo o ponad 19% przyrost pojemności magazynowych. W niektórych krajach takich jak Austria, Holandia czy też Hiszpania nastąpił przyrost o ponad 100%.
Rysunek 4. Przebieg zapotrzebowania i dostaw gazu ziemnego wysokometanowego w 2006 roku

Tabela 2. Zmiana pojemności magazynowych w wybranych krajach UE, (oprac. własne na podstawie [6])

<table>
<thead>
<tr>
<th>Kraj</th>
<th>Pojemności magazynowe [mld m³] do 2000 r.</th>
<th>Przyrost pojemności [mld m³]</th>
<th>[%]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>2,3</td>
<td>4,7</td>
<td>106,3</td>
</tr>
<tr>
<td>Dania</td>
<td>0,8</td>
<td>1,0</td>
<td>27,5</td>
</tr>
<tr>
<td>Francja</td>
<td>11,1</td>
<td>11,9</td>
<td>7,2</td>
</tr>
<tr>
<td>Niemcy</td>
<td>18,6</td>
<td>21,3</td>
<td>14,5</td>
</tr>
<tr>
<td>Włochy</td>
<td>15,1</td>
<td>14,7</td>
<td>-2,3</td>
</tr>
<tr>
<td>Holandia</td>
<td>2,5</td>
<td>5,0</td>
<td>100,0</td>
</tr>
<tr>
<td>Hiszpanii</td>
<td>1,0</td>
<td>2,4</td>
<td>136,7</td>
</tr>
<tr>
<td>Wlk. Brytani</td>
<td>3,6</td>
<td>4,4</td>
<td>20,8</td>
</tr>
<tr>
<td>Polska</td>
<td>1,3</td>
<td>1,6</td>
<td>26,2</td>
</tr>
<tr>
<td>Belgia</td>
<td></td>
<td>0,6</td>
<td></td>
</tr>
<tr>
<td>Finnlandia</td>
<td></td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Grecja</td>
<td></td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Irlandia</td>
<td></td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Luksemburg</td>
<td></td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Portugalia</td>
<td></td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Szwecja</td>
<td>0,7</td>
<td>0,3</td>
<td>42,6</td>
</tr>
<tr>
<td>UE15 + Polska</td>
<td>57,0</td>
<td>68,4</td>
<td>19,4</td>
</tr>
<tr>
<td>Pozostałe kraje UE</td>
<td>17,9</td>
<td>8,9</td>
<td></td>
</tr>
<tr>
<td>UE27</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Systemowe magazyny gazu w Polsce 87
W Polsce w systemie gazu wysokometanowego funkcjonuje obecnie 6 podziemnych magazynów gazu, przy czym aż 4 z nich są rozbudowywane. Dodatkowo budowany jest kawernowy podziemny magazyn gazu w Kosakowie, którego budowa powinna zostać zakończona w 2013 roku. Oprócz magazynów gazu wysokometanowego w ostatnich latach wybudowano w Polsce magazyny gazu zaazotowanego PMG Bonikowo i PMG Daszewo o łącznej pojemności roboczej 0,16 mld m³. Dodatkowo rozpatruje się kilka innych lokalizacji, dla których prowadzone są lub prowadzono prace studialne, bądź koncepcyjne (rys. 5).

**Rysunek 5. Lokalizacja istniejących i rozbudowywanych podziemnych magazynów gazu w Polsce**

W tabeli 3 zestawiono parametry techniczne pracy podziemnych magazynów gazu, którymi w sezonie 2012/2013 dysponuje operator systemu magazynowego, na którego Prezes Urzędu Regulacji Energetyki wyznaczył PGNiG S.A. w Warszawie. Zestawienie powyższe wskazuje na dalszy wzrost pojemności magazynowych, jak i zdolności zatłaczania, odbioru gazu w instalacjach magazynowych zlokalizowanych na terenie Polski.
5 Strategia i plany rozbudowy podziemnych magazynów gazu dla regulacji pracy systemu przesyłowego i tworzenia obowiązkowych zapasów

Rozbudowa systemu magazynowania musi być ściśle dostosowana do przewidywanego wzrostu zapotrzebowania na gaz, charakterystyki odbiorów, szczególnie w zakresie nierównomierności, a także przewidywanych źródeł dostawy gazu i dopuszczalnej zmienności parametrów. Przewidywany obecnie znaczny rozwój mocy energetycznych w oparciu o paliwo gazowe, spowoduje w tym sektorze znaczny wzrost zapotrzebowania – np. PGE przewiduje w swoim zakresie wzrost zużycia gazu z 600 mln nm$^3$, do 2,3–2,5 mln nm$^3$ już po 2017 r. Podobne plany ma Tauron Polska Energia, który za kilka lat zamierza odbierać ok 2,5 mln nm$^3$ [8]. Biorąc pod uwagę elastyczność pracy elektrowni, czy elektrociepłowni gazowych, należy spodziewać się, że znaczna część z nowobudowanych gazowych bloków elektroenergetycznych pracować będzie z dużą zmiennością zapotrzebowania, bądź też nawet wyłącznie w sytuacji szczycowego zapotrzebowania na energię elektryczną, albo też zastępując moce zainstalowane w elektrowniach wiatrowych.

Na wielkość zapotrzebowania pojemności magazynowych może mieć wpływ również budowa terminalu LNG w Świnoujściu [13] i liberalizacja rynku gazu,
w konsekwencji możliwość powstania w rejonie Świnoujścia rzeczywistego hubu gazowego (miejsce, gdzie biega się wiele gazociągów i tras przesyłu surowca z różnich kierunków) [9,10], który dla zapewnienia odpowiedniej płynności i pewności obrotu gazem, może także wymagać nowych pojemności magazynowych. Kolejnym czynnikiem, który należy rozważyć jest ewentualne odkrycie i zagospodarowanie znacznych złóż gazu z łupków. Częściowo na ww. kwestie daje odpowiedź sytuacja na kontynencie amerykańskim, gdzie ze względu na brak wystarczającej infrastruktury przesyłowej [11], występują przypadki spalania wydobycznego gazu, pomimo iż Stany Zjednoczone posiadają największe pojemności magazynowe na świecie [12]. Należy spodziewać się, że gdyby występowały możliwości zmagażynowania tych nadwyżek gazu to zostałby on zmagażynowany. Wynika stąd, iż w okresie najbliższych lat wystąpi dalszy wzrost nierównomierności zapotrzebowania na gaz, a tym samym wzrośnie znaczenie i potrzeby magazynowania gazu. Rozwój pojemności magazynowych musi być ścisłe skorelowany z rozbudową systemu przesyłowego, tak aby wybrać optymalne warianty rozbudowy systemu przesyłowego i instalacji magazynowych. Wobec zajmowania się tymi zagadnieniami dwóch odrębnych podmiotów – tzn. operatora systemu przesyłowego Gaz System S.A. w zakresie systemu przesyłowego oraz Polskiego Górnictwa Naftowego i Gazownictwa S.A. w zakresie systemu magazynowego – zachodzi potrzeba ścisłego współdziałania tych podmiotów, a biorąc pod uwagę zachodzące obecnie i przewidywane zmiany na rynku gazu także konieczne jest opracowanie szerokiego programu dalszej rozbudowy systemu magazynowego.

6 Potencjalne możliwości budowy pojemności strategicznych oraz euromagazynów

Warunki geologiczne w Polsce umożliwiają lokalizowanie na jej obszarze znacznych pojemności magazynowych. Biorąc pod uwagę położenie Polski na drodze transportu gazu z Rosji, tzn. największego producenta gazu do Unii Europejskiej (nawet uwzględniając omijające Polskę układy przesyłowe, z którymi łatwo możemy się powiązać), jesteśmy predysponowani do wykorzystania występujących struktur jako pojemności magazynowych na potrzeby krajów Unii. Przewidywany rozwój wydobycia gazu z łupków będzie z tym korelował. Lokalizacja struktur podziemnych dla budowy ewentualnych pojemności strategicznych oraz potencjalnych euromagazynów została przedstawiona na rys. 6.
7 Wniosek końcowy

Jak wynika z przedstawionej analizy nowych czynników wpływających na problematykę podziemnego magazynowania gazu, należy stwierdzić, iż istnieje potrzeba i uzasadniona jest dalsza rozbudowa pojemności magazynowych. Jeśli założyć, że cena gazu równomiernie importowanego, bądź kupowanego w okresie letnim jest tylko kilka procent niższa od ceny gazu w szczycie zapotrzebowania [13] (obecne warunki cenowe gazu importowanego z Rosji należy uznać za wynikające z nie- rynkowej sytuacji wymagające zmiany, co PGNiG stara się realizować), to nakłady ponoszone na budowę podziemnych magazynów gazu, powinny przynieść satysfakcjonujące stopy zwrotu nawet w okresie kilkuletnim. Inne zalety usługi jakie mogą zostać zapewnione przez PMG będą dodatkową, bezdyssyjną korzyścią. Ważne jest zatem kontynuowanie szczegółowych analiz i prac koncepcyjnych, w celu doprecyzowania wymaganych parametrów PMG, ich lokalizacji, funkcji i sposobu współpracy z systemem przesyłowym oraz systematyczna rozbudowa pojemności magazynowych.

Praca wpłynęła do redakcji w czerwcu 2012r.
This paper discusses issues related to underground gas storage in terms of its system use. Paper presents the current state of storage facilities in Poland and highlights of the views of authors on the further development of system storage capacity in terms of changes occurring in the gas associated with the development of gas energy, gas market liberalization, the development of shale gas production.
Natural gas in Poland and the European Union

The paper describes the structure of natural gas demand and supply in Poland and the European Union (EU) countries, in recent years, with a particular focus on the extraction of this raw material from domestic reservoirs. The status of diversified natural gas supplies to Poland has been compared to individual EU countries. When analysing the EU supply profile particular attention has been given to a growing share of liquefied natural gas (LNG) imports in recent years. A comparison has been made to show how over the past years the economic crisis has affected this fuel demand in the EU countries.

1 Introduction

The last few decades have seen an incremental demand for natural gas worldwide. This raw material is widely used in a number of sectors of the economy – industries, services and residential customers. In many countries natural gas is also widely used in electricity generation [4,9,24]. In Poland, for this purpose, the use of gas is limited, due to significant coal reserves. However, it should be expected that the incremental demand for electricity, advanced age structure of
domestic power plants and the objectives of European and national energy policy on reducing the impact of energy sector on the environment, will encourage investments in high efficiency gas-fired power generation units in Poland. It is projected that both in Poland, in the European Union (EU) or worldwide the demand for natural gas will increase.

2 Natural gas significance in the structure of primary energy consumption

The largest share in the structure of world energy-producing raw materials is represented by solid fuels (67%), and the combined share of natural gas and crude oil is some 33%. The domestic structure is strongly dominated by solid fuels – their combined share is approximately 99%. Hydrocarbon fuels account for less than 1% of market share: natural gas – 0.40%, coal bed methane – 0.35%, crude oil – 0.10%. By virtue of significant resources of solid fuels, Poland is one of the least dependent on energy imports in the EU [17,19]. Only Denmark is a net exporter of energy-producing raw materials. Figure 1 shows the dependency rate of EU countries on external natural gas supplies.

![Figure 1. Energy dependency in the European Union – natural gas, 2009 [2].](image)
When assessing the level of EU’s energy security by reliance on natural gas imports in 1999–2009, adverse evolution can be seen in this regard. While in 1999 this EU’s dependence rate was 48%, in 2009 it moved upwards to 64%. As shown in Fig. 2, only two EU countries are net exporters of natural gas: Denmark and the Netherlands. A relatively good position of Poland has been also noticed, whose dependency rate on external suppliers amounts to 70%. Such an indicator would seem high, however, it is one of the lowest in the EU [2].

The share of domestic natural gas in primary energy consumption totals 13% and is approximately twice lower than in the EU or worldwide. When analysing the share of gas in this structure across EU individual countries, considerable variation can be seen: in some countries this share is at a similar level as in Poland (e.g. Greece – 8%, Portugal – 14%), in other countries it is much higher (e.g. Hungary – 46%, Italy – 38%, UK – 36%). In recent years, the importance of natural gas has been growing in the EU and worldwide. Over the last ten years, the annual natural gas consumption around the world has increased by 29%, whereas in the EU by 9% [1]. In the same period, in some countries, a more than twofold increase in natural gas consumption has been observed (China, Spain). In 2010, gas consumption increased by 7.4% at a global scale, in respect of 2009, and this increase was identical in the case of the EU. It is worth noting that in some EU countries, the dynamics of growth in gas demand in 2009-2010
was a two-digit number (Sweden – 39%, Czech Republic – 14%, Netherlands – 12%) [1]. It is predicted that by 2030 gas consumption will rise to some 4,831 billion cubic metres (bcm) per year, which equates some 25% of global energy consumption. Considering its share, natural gas would become second energy carrier after crude oil (it currently ranks third, after coal) [16].

3 Determinants of natural gas market in Poland and European Union countries

Indigenous proved natural gas reserves held by the major gas producer (and crude oil as well) – Polish oil & gas joint stock co. (Polskie Górnictwo Naftowe i Gazownictwo SA) – amount, by calculating on methane-rich natural gas, to some 100 billion cubic metres. Domestic natural gas reserves are mainly concentrated in the Polish Lowlands (66% of proved reserves), in the foothills of the Carpathians (29.5%), in the Polish economic zone of the Baltic Sea (3.2%) (gas deposits B4 and B6, oil-gas deposits B3 and B8), while the Carpathians reserves amount only to some 0.9%. This is the current status of conventional natural gas deposits; as for unconventional deposits, over the last few years Poland has become one of the most prospective shale gas markets. It is worth emphasizing that the Polish market, in addition to US and Canada markets, is currently one of the most interesting markets worldwide for companies involved in exploration and extraction of gas from unconventional deposits. The proof is in the presence of international oil companies such as ExxonMobil, Chevron, Talisman and Marathon, which carry out prospection and exploration. Shale gas prospection areas cover approximately 11% of Polish territory, where, for example, two thirds of the Pomerania Province coincides with the concession areas. There is a hundred and eleven concessions issued to prospect for unconventional hydrocarbon reservoirs, as of May 2012; the intensification of prospection, optimistic forecasts for gas reserves in Poland and first positive results of prospection is very good news. Nevertheless, shale gas volume estimates reported by consulting companies and the State Geological Institute still remain a prediction based on the comparison of geological features Poland and the US. More will be said about the actual reserves of shale gas after the completion of prospection and exploration work, and verification of the submitted geological study.

In April 2011, a report was released dealing with global shale gas reserves, commissioned by EIA (the US Energy Information Administration). The study provides forecasts for gas reserves of 32 countries, i.a. Poland. According to the report, Poland may hold 5.3 billion cubic metres (bcm) of gas locked in shales.
So far, some other figures have been mentioned, specifying the amount of natural gas reserves in Polish shale reserves. The distribution of projected reserves is significant: from 1.4 bcm (Wood Mackenzie), through 3 bcm (Advanced Resources Int.) up to 5.3 bcm (EIA). In turn, according to the PIG (Polish Geological Institute) estimates of March 2012, Polish probable shale gas reserves shall range from 346 to 768 bcm. The same report indicates that maximum deposits (only of area included in the report) may be as much as 1.92 trillion cubic metres. Taking account of how large and prospective area of the country has not been included at all in the PIG report, it can be estimated that further drilling will contribute to the fact that the estimated volume of reserves is likely to increase even more [25]. All forecasts, based on the similar geological structure in the US, assume that Polish shale gas reserves could be much higher than previously proven conventional natural gas reserves (some 100 bcm).

When considering domestic natural gas reserves, account should be taken also of methane reserves involved with hard coal deposits of the Upper Silesian Coal Basin – 49 deposits with reserves output of 98.6 bcm.

In recent years, extraction of natural gas from domestic natural reserves represented about a third of the domestic demand for gas and represented over 4 bcm. In 2009, production stood at 4.1 bcm. With the implementation of the PGNiG’s strategy involving the increase in the recovery of natural gas from indigenous deposits, in 2011, the volume of production increased to some 4.4 bcm. It is worth emphasizing that this year PGNiG is planning to commence extraction of natural gas outside the country, from the reservoirs of the Norwegian Continental Shelf. The company’s goal in this area is to maintain the sustainability coefficient at a minimum level of 1.1 for five consecutive years, which is that within a year about 30 prospection and exploration wells will be drilled. The strategy envisages to increase investment in prospection work. The strategic objective is to increase natural gas extraction, both from domestic and foreign deposits, to the level of 6.2 bcm in 2015 [11]. In the light of this objective, the activity of PGNiG SA in countries such as Egypt, Denmark, India and Pakistan should be underlined. How prospective are these areas may be proved by the fact that, for instance, estimated reserves of natural gas in Libya, for which PGNiG obtained the right to carry out exploration work, amount to 146 bcm, and as such they are larger than domestic proved reserves of gas.

To satisfy the demand for gas, its import is needed mainly from eastern sources (Tab. 1). In 2011, natural gas sales exceeded 14.5 bcm. In recent years, the natural gas import structure has not substantially changed – natural gas supplies from eastern sources are predominant. A certain change is a result of the Russia-
Ukraine gas crisis from the early 2009 [7]. Natural gas imports from eastern sources are assured by the following collection points: Drozdowice, Wysokoje, Tietierowka and the Yamal pipeline (Łódźwiek Wielkopolski and Włocławek). Instead, from western sources the import is assured by one collection centre located in Lasów (in 2011, the facility developing works were completed and currently its capacity has increased to some 1.5 bcm/y). In 2011 as well, an interconnector was completed in the vicinity of Cieszyn, on the Polish-Czech border, and therefore it is possible to receive gas from that source in an amount of some 0.5 bcm/y.

Table 1. Natural gas supplies into Poland, 2005–2011 in million cubic metres.

<table>
<thead>
<tr>
<th>Source</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Domestic output</td>
<td>4 318.1</td>
<td>4 277.1</td>
<td>4 276.0</td>
<td>4 073.9</td>
<td>4 078.6</td>
<td>4 220.0</td>
<td>4 447.9</td>
</tr>
<tr>
<td>Gas import, including:</td>
<td>9 690.6</td>
<td>10 028.4</td>
<td>9 286.6</td>
<td>10 264.1</td>
<td>9 485.3</td>
<td>10 066.4</td>
<td>11 174.48</td>
</tr>
<tr>
<td>Russia</td>
<td>6 340.3</td>
<td>6 839.7</td>
<td>6 219.2</td>
<td>7 056.7</td>
<td>7 579.9</td>
<td>9 028.4</td>
<td>9 549.1</td>
</tr>
<tr>
<td>Germany</td>
<td>300.6</td>
<td>477.5</td>
<td>783.6</td>
<td>825.4</td>
<td>1 072.8</td>
<td>1 031.9</td>
<td>1 625.16</td>
</tr>
<tr>
<td>Norway</td>
<td>485.1</td>
<td>360.1</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>0.3</td>
<td>0.3</td>
<td>0.3</td>
<td>0.0</td>
<td>0.3</td>
<td>0.3</td>
<td>0.22</td>
</tr>
<tr>
<td>Central Asia</td>
<td>2 533.1</td>
<td>2 346.9</td>
<td>2 279.3</td>
<td>2 377.2</td>
<td>667.5</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Ukraine</td>
<td>1.2</td>
<td>3.9</td>
<td>4.2</td>
<td>4.8</td>
<td>5.9</td>
<td>5.9</td>
<td>0.0</td>
</tr>
<tr>
<td>TOTAL</td>
<td>14 008.7</td>
<td>14 305.5</td>
<td>13 562.6</td>
<td>14 338.0</td>
<td>13 564.9</td>
<td>14 286.4</td>
<td>15 622.38</td>
</tr>
</tbody>
</table>

When analysing possibilities of natural gas supplies to Poland, it should be also stressed that through regulating the operator issue of the Polish section of the Yamal-Europe pipeline, from November 2011, gas supplies are carried through a service, the so-called virtual reverse flow service. Therefore, in this way, there are opportunities to bring to Poland more than 2 bcm of gas per year.

As shown in Tab. 1, in recent years most of the natural gas was supplied by the Russian Gazprom. Natural gas from eastern sources – in the analysed period – was imported into Poland through a long-term contract, which is valid until 2022 (supplies from Gazprom) – Fig. 2. In the case of the EU, too, gas supplies from Russia play an important role in balancing the demand. However, in recent years, a reduction in Russian gas supplies to EU countries can be noticed. As scheduled, in 2012 Gazprom is expected to supply 150 bcm of natural gas to the EU. Also in the future, the Russian Federation will seemingly remain the major gas exporter to a number of EU countries. This is mainly due to geographical features, existing or under construction transport infrastructure, as well as on the one hand to the fact that this country holds the world’s largest proved reserves of gaseous fuel, on the other hand to the EU’s growing dependency rate on gas imports (41% in 2005, 60% in 2015, and 71% in 2025–2025) [17]. Launching on
a large scale developments of unconventional natural gas deposits could change anticipated trends in the EU in terms of further dependency on supplies from third countries. As a recent experience has shown in US markets, a rise in gas supply, mainly from shale formations, resulted in a significant decline in gas prices – Fig. 3 [27].

Diversification of gas supply sources enhances energy security. This is particularly true when gas supply disruptions are noticed from a given source. In the European Union there are significant differences in solving the issue of diversification of natural gas supplies. Some countries have even diversified their natural gas supplies in an exemplary way; fuel supplies are carried out both by gas pipelines and as liquefied natural gas (LNG) (Spain, France, Italy), while others are almost exclusively reliant on Russian gas supplies (Slovakia, Lithuania).

It should be underlined that the increase in natural gas extraction in the US, mainly from unconventional deposits, was reflected in trends evolution in the liquefied natural gas (LNG) market – more volumes of this gas could be directed to European consumers. While in 2008, LNG accounted for 13% share in the structure of gas imports to the EU, in 2010, this share increased to 24%. In 2010, among EU countries with possible liquefied natural gas reception capacities were (in parentheses the number of regasification facilities is shown): Belgium (1), France (3), Greece (1), Italy (2), Portugal (1), Spain (6) and the United Kingdom (4). Among EU countries with greatest regasification capacity are: Spain (63.3 bcm), the United Kingdom (53.9 bcm) and France (25.1 bcm).
As shown by Eurogas preliminary data for 2011, the economic situation of EU countries, and relatively high temperatures at the end of 2011 resulted in a reduction in demand for natural gas. In 2011, as compared to 2010, EU-27 recorded some 11% drop in demand for natural gas; the largest reduction was observed in Greece – 23%, in Sweden – 21%, in the UK – 18%, in Denmark – 18%, in Ireland – 13%. When analysing the drop in EU demand for natural gas, expressed in billion cubic metres, the ranking is as follows: the United Kingdom – 18, Germany – 12 and the Netherlands – 6.

It is estimated that in 2015 European regasification terminal capacity will reach 225 bcm. Thus, gas transport technology in the form of LNG will develop dynamically [3]. Currently, according to the Energy Policy of Poland until 2030, one of the main tasks in the area of gas supply security is to build an LNG terminal for the reception of liquefied natural gas. Responsible for the implementation of this project are Polskie LNG sp. z o.o., the Maritime Office in Szczecin, the Szczecin-Swinoujście Seaports Authority, and the gas transmission operator GAZ-SYSTEM S.A. In the first stage of the operation, the LNG terminal will enable the regasification of 5 bcm of natural gas per annum, then, in the next stages the regasification capacity will grow to 7.5 bcm [10]. On 29 June 2009, a long-term contract was concluded (a 20-year contract) for sale and supply of liquefied natural gas from Qatar to Poland. Under this agreement, Qatargas will supply to PGNiG SA 1 million tonnes of LNG per year. It is worth noting that Qatar is currently the world’s largest producer of LNG (39.68 bcm in 2008,
75.6 bcm in 2010). The country has three export terminals and others are in progress. These investments are likely to maintain its dominant position in the global LNG market.

When analysing the structure of natural gas consumption in Poland and EU countries, some differences can be noticed (Fig. 5). In the case of our country, the largest consumer of natural gas is the industrial sector (nitrogen plants, metallurgy, power industry) – it represents some 60% of total consumption, approximately 29% is sent to residential customers, and the remainder is delivered to commercial sector and services – Tab. 2.

Table 2. Natural gas sales in Poland, 2006-2010 in %.

<table>
<thead>
<tr>
<th>Description</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industries, including:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nitrogen works</td>
<td>18.00</td>
<td>17.70</td>
<td>17.70</td>
<td>15.45</td>
<td>15.50</td>
</tr>
<tr>
<td>Power plants &amp; CHP</td>
<td>7.60</td>
<td>7.50</td>
<td>7.60</td>
<td>7.96</td>
<td>7.98</td>
</tr>
<tr>
<td>Heat plants</td>
<td>1.80</td>
<td>1.80</td>
<td>1.80</td>
<td>2.21</td>
<td>2.21</td>
</tr>
<tr>
<td>Others</td>
<td>33.30</td>
<td>35.40</td>
<td>34.90</td>
<td>33.64</td>
<td>33.74</td>
</tr>
<tr>
<td>Commercial &amp; Services</td>
<td>10.00</td>
<td>9.60</td>
<td>9.70</td>
<td>10.36</td>
<td>10.39</td>
</tr>
<tr>
<td>Residential</td>
<td>28.50</td>
<td>28.70</td>
<td>28.50</td>
<td>28.46</td>
<td>28.54</td>
</tr>
<tr>
<td>Export</td>
<td>0.30</td>
<td>0.30</td>
<td>0.30</td>
<td>0.31</td>
<td>0.00</td>
</tr>
<tr>
<td>Industrial pipelines &amp; Distribution system operators</td>
<td>0.60</td>
<td>1.10</td>
<td>1.50</td>
<td>1.62</td>
<td>1.62</td>
</tr>
</tbody>
</table>

Figure 5 shows that the EU’s structure of natural gas sales is characterised by
dominating gas supplies to industry customers (industries and power generation). However, compared to our country, much more gas is purchased for electricity generation. In Poland, some 8% (ca. 1 bcm) of gas sold is delivered to power generating sector. For the EU, this share is 27%, in some countries it exceeds 30%, for example, in Portugal – 45%, Sweden – 47%, Italy – 36%, Ireland – 66%. When analysing changes in the structure of electricity generation in the EU in the last ten years one can see an increasing importance of natural gas and renewable energy sources. Currently, natural gas is second, after coal, primary energy carrier most widely used to generate electricity in the EU countries – Fig. 6.

Poland’s electricity generation structure is different: given significant reserves, it is dominated by solid fuels – total share of coal in this structure was 88.5%. Natural gas accounts for 3% of share. Current plans and intentions of energy companies assume significant progress in the development of gas use in electricity generation. It is projected that in the future, the importance of natural gas in electricity generation in the EU will be growing [21].

4 Natural gas demand – outlook

According to the International Energy Agency forecasts, published in 2010, in the New Policies Scenario the global demand for primary energy will amount to 16.7 billion toe in 2035, which will represent a 36% increase compared to 2008. The average annual growth should reach 1.2%. However, in the Current Policies
Scenario it is expected that the average increase in primary energy consumption will be at 1.4% per annum. In the 450 Scenario, energy demand growth will be only some 0.7% per year. Fossil fuels like oil, natural gas and coal remain predominant energy sources in each of the three scenarios, but their share in total primary energy balance varies considerably. Table 3 shows the IEA’s forecasts on the structure of energy balance by 2035. When looking at the future demand for natural gas one can see that, regardless of the scenario, a growth has been planned, and in the case of New Policies Scenario, demand for gas in 2035 is almost as high as for coal (80% of demand come from non-OECD countries) [26].

Table 3. Global demand for primary energy according to individual scenarios in Mtoe [26].

<table>
<thead>
<tr>
<th>Description</th>
<th>Current Policies Scenario</th>
<th>New Policies Scenario</th>
<th>450 Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2020</td>
<td>2035</td>
<td>2020</td>
</tr>
<tr>
<td>Coal</td>
<td>4307</td>
<td>5281</td>
<td>3966</td>
</tr>
<tr>
<td>Oil</td>
<td>4443</td>
<td>5026</td>
<td>4346</td>
</tr>
<tr>
<td>Natural gas</td>
<td>3166</td>
<td>4039</td>
<td>3132</td>
</tr>
<tr>
<td>Atomic energy</td>
<td>915</td>
<td>1081</td>
<td>968</td>
</tr>
<tr>
<td>Hydropower</td>
<td>364</td>
<td>439</td>
<td>376</td>
</tr>
<tr>
<td>Biomass and waste</td>
<td>1461</td>
<td>1715</td>
<td>1301</td>
</tr>
<tr>
<td>Other renewables</td>
<td>239</td>
<td>468</td>
<td>268</td>
</tr>
<tr>
<td>Total</td>
<td>14896</td>
<td>18048</td>
<td>14556</td>
</tr>
</tbody>
</table>

Figure 7. Natural gas consumption in EU 27 – Eurogas Roadmap 2050.

When analysing the volume and structure of the EU’s demand for gas, one can see that the largest increase is expected to be in electricity generation sector, especially in the period between 2010 and 2030. Also by 2030, a dynamic growth in gas demand as fuel for transport is being planned (Fig. 7).

– 20.2 bcm. As mentioned previously, future growth in demand will be dictated mainly by the development of natural gas use in electricity generation (gas – steam units).

5 Conclusion

There has been noticed an incremental demand for natural gas, both in the EU and worldwide, in recent years. Also available forecasts predict the increase in demand for natural gas. Both the EU and Poland energy policies promote electricity generation technologies that are characterised by low-degree negative impact on the environment and high efficiency (modern gas-steam units reaching 60% efficiency of electricity generation) [5]. The demand for natural gas in Poland will be significantly affected by implementing more investments in natural gas energy. The current demand in the electricity sector is approximately 1 billion cubic metres. However, taking account of investment implementations (e.g. construction of a gas/steam unit in CHT Stalowa Wola) and those being planned (e.g. in Wloclawek, Gorzów, Konin and Wroclaw), in the perspective of next eight years, with an optimistic scenario, electricity generation will need some 6 bcm/y. So far, this option is not very realistic given that some projects are far from being completed. However, taking account of significant solid fuels reserves on the one hand and EU’s energy policy objectives on the other hand (mainly reduction of carbon dioxide emissions), the national energy sector will move towards a coal-gas model [23].

The gas crisis of early 2009 revealed in some countries lack of adequate preparation in the event of supply disruptions. It should be noted that since then the level of security of gas supplies to Poland increased through the development of natural gas interconnectors (Lasów, Cieszyn) and investments in the development of underground natural gas storage facilities (PMG Strachocina, PMG Wierzchowice, PMG Daszewo). To further increase supply security, the development of LNG terminal in Świnoujście is of crucial importance, as well as the development of transmission network of high pressure pipelines with their total length exceeding 1000 km.

When analysing recent changes in the European natural gas market, it is worth emphasizing the increasing volume of natural gas supplies through spot contracts. In 2011, natural gas supplies through long-term contracts (mainly supplies from Gazprom and Statoil) accounted for 55% of share of the total volume of natural gas imported into Europe; under these contracts the pricing paradigm adjusted prices for natural gas by referencing petroleum product quo-
tations. Sustained increase in crude oil prices contributed to a change in the European market, where, since the beginning of this year, a dynamic growth in natural gas sales on the basis of spot gas pricing has been observed. In the current year, already, the volume of gas supplies into Europe through spot contracts is likely to exceed natural gas supplies through long-term contracts.

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Gaz ziemny w Polsce i Unii Europejskiej

S t r e s z c z e n i e

W artykule przedstawiono strukturę popytu i podaży na gaz ziemny w ostatnich latach w Polsce i krajach UE, ze szczególnym uwzględnieniem wydobycia tego surowca z rodzimych złož. Porównano stan dywersyfikacji dostaw gazu ziemnego do Polski na tle wybranych państw UE. Analizując strukturę dostaw do UE zwrócono uwagę na rosnący udział w ostatnich latach importu gazu skroplonego (LNG). W artykule porównano jak w ciągu ostatnich lat kryzys gospodarczy wpłynął na zapotrzebowanie na to paliwo w krajach UE.
Unconventional natural gas — USA, the European Union, Poland

The global gas market is currently undergoing considerable changes. The most promising places in Europe, as far as the natural gas search and output potential from unconventional resources is concerned, are Austria, Hungary, Poland, Germany and Sweden, among others. Taking into consideration the status of supplies of this type, which is still quite uncertain, and the possibilities of their output in Europe, the European Union (EU), in its prognoses, still does not consider them in the total assessment of demand and supply of natural gas for the EU. The conservatism of Europe is fully justified because practically nobody in Europe possesses “know-how” (lack of equipment or human resources which could be soon referred to defined operations.) What is absolutely necessary is verification of assumptions of the Polish energy policy (PEP2030). The possibility to prepare and, possibly, implement the principles of common energy policy of the EU must be considered.

1 Introduction

The last several years, in particular the period 2009–2012, was a time when the technological revolution of gas search and output from unconventional resources, especially the shale natural gas, changed the American economy and opened
completely new possibilities for the energy sector of the United States (US). This is the time when natural gas reaches its historically lowest prices stimulating the economic growth, when unemployment declines and new workplaces are created. It is the first time for many years when gas prices stabilize, as well as the level of national output which enables a considerable limitation of gas import needs in liquefied natural gas (LNG) form and the USA become a net exporter of this energy material. In the USA natural gas becomes a natural substitute of hard coal and a possibility of much more extensive use of renewable energy sources for generation of electric current. As it is stated in the IHS Cambridge Energy Research Associates (CERA) report [4] of December 2011, this economic activity considerably affects the economy of the USA, for instance:

- Employment: only in 2010 in the USA the industry connected with shale gas led to creation of at least 6 million new workplaces. CERA estimates that by 2035 it is going to be a total of 1.6 million workplaces in the American economy [4].
- Revenues: IHS Global Insight [4] expects that the yearly revenue of the America’s budget, resulting from taxation of personal revenues and those of enterprises will rise from USD 18.6 billion in 2010 to USD 28.6 billion in 2015 and to USD 57.3 billion in 2035. Moreover, so-called royalty payments for the country will rise from USD 161 million in 2010 to USD 239 million in 2015 and they will exceed USD 580 million in 2035.

The global, in particular European (i.e. the European Union) gas market is currently undergoing considerable changes. Only at the beginning of 2008 most of the analytics expected a systematic, continuous increase in gas consumption and continuance of trends which shaped within 20–30 previous years (e.g. average increase in consumption of LNG in the world in the amount of 7.4% per year in the years 1965–2007 [3]). However, the economic slowdown that started in 2008 with the financial crisis and considerable increase in own gas production of the US significantly changed the gas market. As a result, there was natural gas ‘excess’ on the market – i.e. possibilities of its delivery by the manufacturers are much higher than the ‘appetite’ of consumers. This is particularly visible in the case of LNG market, where the excess of assets in the entire value chain, starting from liquefying plants, through liquid gas carriers to regasification terminals, led to freezing (or even abandonment) of practically all new investment projects, with a simultaneous decrease of production powers, ships used to transport LNG and receiving terminals [5,6].

Breaking the continuance of economic processes leads to considerable limitation of the possibilities of using research instruments created in the past. Analyses
and prognoses connected with gas production and consumption performed before 2008 are useless in the current situation. The prognoses that were made after 2008 are based on too short time series, and they describe moreover, the global economy being ‘in shock’, attempting to regain its balance in the new reality. Therefore, they are naturally inexact and it is very risky to draw far-reaching conclusion based on them. These economic phenomena were, at the same time, overlapped by technological revolution in natural gas output from unconventional resources in North America. Due to great demand, developed transfer structure and similarity of geological structures to the US, the market of the EU seems to be a very promising for gas search and output from these sources. Thanks to unconventional gas sources, proved reserves of this resource rose in the USA from the amount of 5 trillion m$^3$ in 2000 to the level of approximately 6.95 trillion m$^3$ in the end of 2008 only to rise by 77% in 2011 and reach the level of 12.3 trillion m$^3$, although in the same period, the total output volume in the US amounted even to 4.3 trillion m$^3$. The estimated level of the output gas reserves from unconventional resources in Europe is assessed for between 2.8 to 11.3 billion m$^3$. Assuming that the proved reserves may constitute approximately 30% of the entire supplies, the potential of own production in Europe (excluding Norway and countries of the FSU) may, theoretically, increase by 30–120%, giving an additional yearly amount of 60–200 billion m$^3$ gas from own, European sources. The most promising places in Europe, as far as the gas search and output potential from unconventional resources is concerned, are Austria, Hungary, Poland, Germany and Sweden among others. Taking into consideration the status of supplies of this type, which is still quite uncertain, and the possibilities of their output in Europe, the EU, in its prognoses still does not consider them in the total assessment of demand and supply of natural gas. The subject of prognoses for EU market has been discussed in [7].

Since 2009 attempts have been made to assess the amount of natural gas in Polish unconventional supplies. Due to the insufficient amount of information, different methodologies applied and statistical calculations made based on data concerning North-American supplies, these estimates are vastly different. As-

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2This is, most of all, caused by the development of shale gas output in Louisiana, Arkansas, Texas, Oklahoma and Pennsylvania [15].

3All proved gas reserves in Europe (excluding Norway and countries of the FSU) amounted, at the end of 2010, to approximately 2.7 trillion m$^3$. Source: *BP Statistical Review of World Energy, June 2011*.

sessments made by respected international institutions concerning the amount of shale gas supplies possible to mine reach from 1.37 trillion m$^3$ (Wood Mackenzie, August 2009) [15,16], through 1.87 trillion m$^3$ (EUCERS, May 2011) [9], 2.83 trillion m$^3$ (Advanced Resources International, December 2009), to 5.3 trillion m$^3$ (EIA, April 2011) [3,5,6]. The latest description of EU supplies can be found in [10]; compare also [11]. In March 2012, the first assessment of these supplies – only for the Baltic and Lublin–Podlasie Basin – was made by Polish Geological Institute (Państwowy Instytut Geologiczny – PIG). In the published report [14], total supplies of natural gas from shale formations, possible to mine, for Polish land and shelf (sea) part of the Baltic and Lublin-Podlasie basin were assessed for the maximum of: 1.92 trillion m$^3$. PIG also assessed that, most probably, these supplies also fall into the range 346–768 billion m$^3$ (2.5 to 5.5 times more than the documented supplies of conventional gas). Analogous amounts for shale oil (the same area) amount to the maximum of 535 million tons and, most probably, in the range: 215–268 billion tons (8.5 to 10.5 times more than the documented supplies from conventional gas.

Comparing the amounts gained by PIG and international institutions, several essential facts must be stressed:

- The estimates of PIG were made only for the Baltic and Lublin-Podlasie basin, not for the entire area of Poland (together with the supplies of Przedgórze Sudeckie), as it was made by international institutions.
- PIG for the first time indicated relatively large (when compared to the entire country) amounts of oil in shale.
- The PIG report has been made based on archive data, obtained from diagnostic holes made between 1950 and 1990. This data was well-known to all companies which decided to search for gas in Polish shale formations. The PIG assessments may change (and they probably will) having taken into consideration the data obtained from exploratory boreholes made after 1990 (in particular after 2010) during performance of exploratory and mining works for shale hydrocarbons$^5$. Compare [1,2]!

$^5$As far as the assessment of the PIG report is concerned, it should be taken into account that opinions concerning it – even among Polish experts – are divided. For instance, the information of Polish Press Agency (PAP) of 2nd April 2012 may be quoted here:

As professor Stanisław Nagy, the head of the Gas Engineering Department in AGH, said, what is the most important problem is the methodology US Geological Survey (USGS), assumed by the Institute, which leads to - in his opinion - considerable underrating of these supplies due to lack of production wells in Poland. Nagy states that, due to the fact that there is no data concerning
2 A review of market environment in natural gas search and output from unconventional supplies, with particular taking into consideration of so-called shale gas

Currently in Poland, in accordance with information of the Ministry of the Environment as on May 1, 2012, 19 entities were granted 110 concessions for searching for shale gas. The map of concessions is presented in Fig. 1. The following companies (some of them operate through their subsidiaries) have the concessions for searching for shale gas:

- PGNiG SA – 15,
- PETROLINVEST S.A. – 13,
- Marathon Oil Poland Sp. z o.o. – 11,
- 3Legs Resources Plc (Lane Energy) – 9,
- Orlen Upstream Sp. z o.o. – 7,
- LOTOS Petrobaltic Sp. z o.o. – 7,
- BNK Petroleum – 6,
- ExxonMobil Exploration and Production Poland Sp. z o.o. – 6,
- San Leon Energy – 6,

Shale gas output in Poland, “it would be more favourable to estimate only the geological gas supplies, based on classic methodology, so-called PRMS, too, approved by numerous international associations and institutions, such as, among others: Society Petroleum Engineers, American Association of Petroleum Geologists or World Petroleum Council, commonly applied in all gas and oil companies. The expert explained that the classic method is applied, among others, to examine the volume of the gas-saturated supply, saturation with formation water (ground water accompanying a supply), rock porosity, also the amount of free gas in fissures and pores is assessed. Obviously, such examinations are more difficult, as they are more time-consuming and require detailed data, also from the process of test mining” – he said. The head of Polish Geological Institute (PIG) Jerzy Nawrocki explained that the American (USGS) geological service is “the authority on this field and it estimates the supplies not only for the United States, but, upon the request from the US government, it make reports for the entire world, with the use of the same methodology”. In his opinion, the so-called classic method of estimation of geological supplies does not take mining possibilities into account, and this is what is the main interest of everyone in the case of unconventional supplies. “We decided that it is better to speak about resources technically possible to mine than promise great geological supplies” – he said. “In my opinion, our approach is more realistic. The report concerns techniques applied today. If there are new ones and if there is more data from other boreholes, we are going to update our studies” – he explained.
Figure 1. Map of concessions for searching for shale gas, state as on May 1, 2012 [19].

- Strzelecki Energia Sp. z o.o. – 6,
- Emfesz (DPV Service Sp. z o.o.) – 5,
- Chevron Corporation – 4,
- Eni Polska Sp. z o.o. – 3,
- Realm Energy International Co. – 3,
- Talisman Energy Polska – 3,
- Cuadrilla Polska Sp. z o.o. – 2,
Aurelian Oli & Gas Poland Sp. z o.o. – 2,
Dart Energy Poland Sp. z o.o. – 1,
Mac Oil (Poland) Sp. z o.o. – 1.

Currently, on the aforementioned concessions, only exploratory works are performed, gas output has not started yet. Only on two concessions, their owners (PGNiG and San Leon) informed about discovery of shale gas. Research performed by ExxonMobile in two boreholes ended in a fiasco and the company, in its report, stated that ‘the two test boreholes made at the end of 2011 with the aim of searching for shale gas in Poland, turned out to be disappointing. The amount of gas found in the first boreholes of ExxonMobil in Poland was insufficient to start regular, commercial output of the raw material\textsuperscript{6}.

As far as the total amount of concessions for search and recognizing of hydrocarbons is concerned (oil and natural gas in conventional and unconventional supplies – including shale gas), their amount reaches 257 (including 96 concessions of PGNiG). At the same time, the amount of concessions for output of hydrocarbons, granted by the Ministry of the Environment, amounts to 233\textsuperscript{7}. From the aforementioned number of 233 output concessions, 225 belong to PGNiG, 4 to Lotos Petrobaltic, 2 to San Leon Energy and one each to FX Energy and DPV Service. In natural gas output, similarly to the remaining areas of gas operations, in Poland, (apart from gas transfer) PGNiG plays a dominant role. The national output reaches 4–4.5 billion m\textsuperscript{3} per year and this amount is rising. Other companies dealing with gas output play minor roles (with the output amounting to 100–150 million m\textsuperscript{3} per year, they have a total of 2–3% share in the national output).

As far as total documented supplies of natural (conventional) gas are concerned, depending on the source, they are assessed in the range from 100 to a little more than 150 billion m\textsuperscript{3} in terms of methane-rich gas. Approximately 2/3 of Polish gas supplies is located in Niż Polski (Polish Lowlands) (mainly high-nitrogen gas), 30% in Przedgórze Karpackie (Carpathian Foreland) (methane-rich gas), not quite 1% in Karpaty (the Carpathian Mountains) and approximately 3% on the shelf of the Baltic Sea [14]. The exploratory and mining operations, when it comes to conventional gas in Poland, are mainly concentrated in Wielkopolska (Greater Poland) and in Podkarpackie (Sub-Carpathian region). The supplies of shale gas are supposed to be much larger, yet it must be noticed that in this case

\textsuperscript{6}David Rosenthal, vice-head for investment relations in Exxon.

\textsuperscript{7}[18] Ministry of the Environment, Juxtaposition of concessions for searching, recognizing and output of oil and natural gas supplies in Poland – February 1, 2012; www.mos.gov.pl
the estimates of their size are much more diversified [3]. At the same time, it should be added that specification of this data may take place only as a result of beginning of shale gas supplies mining on an industrial scale.

National gas output constitutes only approximately 1/3 of the natural gas consumption on the Polish market; this consumption amounts to, approximately, 14 billion m$^3$/year$^8$. Approximately 97% from this amount is supplied by PGNiG, in particular from import. As far as import is concerned, a dominant supplier is Gazprom (approx. 10 billion m$^3$ per year). About 3% of gas is sold on the Polish market by companies not being subsidiaries of PGNiG (GEN Gaz Energia, EWE Polska, KRI and CP Energia, among others). The expected freeing of prices on the gas market (probably from 2013 for all recipients, except for households) should change this situation, however, the scale of these changes depends on the model of the target gas market which is supposed to be implemented in Poland and which still is neither prepared, nor defined. In paper [8] consequences of the possible influence of output increase from unconventional supplies on the Polish economy have been discussed more specifically; compare also [6,7].

Currently – unfortunately still in Poland – all kinds of operation on the gas market – transfer, distribution, storing and turnover in gas fuel – are subject to the tariffication obligation. Analogically to the energy market, the function of a regulatory authority is fulfilled by Energy Regulatory Office (Urząd Regulacji Energetyki – URE), also gas tariffs (referring to transfer and distribution) are formed based on the same principles. In accordance with the energy law in Poland, there is one operator of the transfer system (TSO) (OSP – operator gazociągów przesyłowych) – Gaz-System S.A. This company is also an owner of most of transfer gas pipelines. What constitutes the only exception is the transit Yamal pipeline, the owner of which is EuroPolGaz S.A. (but URE designated Gaz-System as the operator).

The main import accesses to the transfer system are located on the eastern border in Wysokoje and Drozdowicze (with flow capacity 650 thousand m$^3$/h and 625 thousand m$^3$/h, respectively – approx. 5 billion m$^3$/year each). Apart from the above, gas is imported through Lasów, through so-called virtual reverse on the Yamal gas pipeline in Mallnow and an access point in Cieszyn, put to use last year (Moravia gas pipeline), but with much smaller flow capacity (after its development – in particular in the Czech part – a total of 1.5–2 billion m$^3$ per year).

$^8$In accordance with Polish standards, all values concerning gas volume are specified in normal cubic metres. A cubic metre of gas fuel in normal conditions (m$^3$) — a unit of measure that indicates the amount of dry gas fuel contained in the volume of 1 m$^3$ in the pressure of 101325 kPa and temperature 0 °C.
The current investments of Gaz-System in the development of the transfer system aim at introduction of possibilities of reversing the traditional directions of gas transfer, mostly – considering the function of the LNG terminal in Świnoujście which is the most important from the investments currently performed in the gas sector in Poland. The first in Poland (and, for the time being, the only one) terminal for gas regasification is being construed in Świnoujście, more precisely – in Warszów – a right-bank district of Świnoujście. The estimated, specified by the investor, investment expenditures only for the construction of the terminal, amount to approximately EUR 500–600 million. The construction of the LNG terminal will allow to increase the diversification of natural gas supply. In the first stage of operations, the terminal will allow to receive 5 billion m$^3$ of natural gas per year. In the next stage, depending on the increase of gas demand, it will be possible to increase the regasification possibilities to 7.5 billion m$^3$/year. Installations to unload LNG will be adjusted to service of Q-flex ships (maximum capacity – 216000 m$^3$, draught – 12.5 m, length – 315 m). The works on the construction of the terminal started in September 2010 and, in accordance with the applied schedule, the date of putting it to use is 30th June 2014.
The main function of the aforementioned Yamal gas pipeline (transit gas pipeline system) is transfer of Russian gas to the German market. Its flow capacity reaches 33 billion m$^3$/year. On the territory of Poland, two gas reception points to the transit network have been constructed on the route of the gas pipeline: in Włocławek (maximum technical flow capacity 350 thousand m$^3$/h, which gives over 3 billion m$^3$/year) and in Lwówek (maximum technical flow capacity 270 thousand m$^3$/h, which gives over 2.3 billion m$^3$/year). At the same time, the access points are Kondratki and Mallnow (only the virtual reverse enabling import to Poland$^9$).

The entity which plays a dominant role in natural gas distribution is PGNiG Group. Its six distribution companies cover the area of the entire country and serve approx. 98% gas consumers. On the areas excluded from PGNiG distribution networks, independent distribution companies operate, from among the only ones which are essential are the aforementioned GEN Gaz Energia, EWE Polska, KRI and CP Energia.

$^9$Technical transit capability in the Mallnow virtual reverse is equal to the sum of technical transit capability of reception points to the Polish system.
3 The developing gas market based on output from unconventional resources?

Whereas a global increase in natural gas demand from the chemical industry in Poland should not be expected – the positive scenario is a return to the consumption level from the years 2006–2008, the need of change or diversification of suppliers of this raw material to nitrogen plants is more and more often mentioned by management boards of these companies, annoyed by the fact that the main supplier – PGNiG treats their enterprises more as balancing elements, cutting off or limiting the supplies in the case of shortage of the raw material in the network than as key customers. This policy of the gas potentiator on the Polish market, which is quite short-sighted, is a great opportunity for new entities developing gas output from unconventional resources, to gain perfect (balanced, stable reception profile) customers. Reaching such ‘dissatisfied’ customers who are, at the same time, determined by the will of change, is possible based on direct contracts between the supplier and the customer, therefore acquiring them by new entities on the gas market seems to be relatively easier. The gas market in Poland, however, will not reflect the situation in the entire EU.

In May 2010 EUROGAS (the European Union of the Natural Gas Industry) published its prognosis titled *Long Term Outlook for Gas Demand and Supply 2007-2030* [19] which, to a great extent, corresponded with the PRIMES baseline model of 2007. Since the document became outdated rather quickly, in October 2011 EUROGAS, replying to the needs of the market, so to speak, prepared another document, which, this time was not of a forecast nature, *Eurogas roadmap 2050*. The authors wanted to describe what a European energy mix could look like in 2050, with the assumed 80% reduction (in relation to the year 1990) of the greenhouse gases emission in the EU, just as it was proposed by the European Commission in a document titled *Roadmap for moving to a low-carbon economy in 2050*.

The aim of *Eurogas roadmap 2050* was to present paths leading to the intended reduction goal which was supposed to constitute the basis for the European debate in December 2011, concerning *Energy roadmap 2050*. The document was created after the crisis in 2009, but still before the fundamental change concerning shutdown of nuclear power plants in Germany after the Fukushima tragedy. Nevertheless, *Eurogas Roadmap 2050* stressed the considerable potential of technologies connected with natural gas – in all sectors – for reaching the reduction goal. The document, in the 2030 perspective shows the advantage given by natural gas in the sector of electric energy and heat and in minimizing CO₂ emission.
An additional benefit of this raw material is the flexibility of adjustment of the
gas sector to the development of renewable energy sources. Roadmap notices
the necessity of implementation of technologies connected with CO₂ capture and
storage (CCS technologies) for the years 2030–50 without the analysis of the in-
fluence of potential of gas from unconventional resources. As it is stated by
the authors of the document, this will practically lead to stabilization of consump-
tion of natural gas in the energy sector at the level of 191 billion m³ in 2050
(with 162 billion m³ in 2010). Furthermore, they are of the opinion that energy
consumption in the sector of households and in the sector of services will decline
to 86 billion m³ as a result of implementation of the energy effectiveness package.
Moreover we can see a considerable increase in consumption of natural gas in
transport in the years 2030–50.

It should be stressed here that one can notice lack of an econometric mar-
ket model (in particular in the case of natural gas market) at the EU level.
This is curious, as demands are made from different areas (also from suppliers
and importers of natural gas) concerning the necessity to prepare such a model
at European level, since the applied PRIMES model does not provide satisfying
prognostic results, nor does it perform well in shorter verification periods.
Furthermore a modern model for the Polish market is absolutely necessary, in
particular when facing the expected shale gas mining. The most important are

Figure 4. Natural gas consumption in the European Union according to Eurogas Roadmap 2050
(source: own study based on Roadmap for moving to a low-carbon economy in 2050).
the analysis and estimation of the influence of the output development and, subsequently, consumption of gas from unconventional resources (in particular shale gas) on the economic and social problems in Poland, taken as a whole, taking into consideration the issues of ecologic nature and energy safety of the country. The results of the study could also constitute an appropriate basis for creation of standard legal, organization, economic, political, ecologic and social solutions, which will enable appropriate and socially acceptable integration of the area of exploration and output of gas from unconventional resources with legal, economic and social frameworks binding in our country.

4 Conclusions

To conclude, we wish to stress, that in spite of more than three-year period of warming up the atmosphere and creation of ‘shale euphoria’ in Poland, other EU countries are very sceptic or even reluctant when it comes to this topic. It is not very possible to speak about a ‘revolution’ on the gas market, the way it is happening in the USA or about economic revolution in this sector. The conservatism of Europe is fully justified, not only because the degree of recognizing and development of possible supplies is at much lower level than in the USA, or because practically nobody in Europe possesses ‘know-how’, but also an appropriate amount of equipment or human resources which could be soon referred to operations of this kind. What is absolutely necessary is verification of assumptions of the Polish energy policy (PEP2030). The possibility to prepare and, possibly, implement the principles of common energy policy of the European Union, must be considered.

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References


Niekonwencjonalny gaz ziemny – Stany Zjednoczone, Unia Europejska, Polska

**Streszczenie**

Energy and economic effectiveness of gas-steam combined heat and power plants fired with natural gas

The paper presents the energy and economic effectiveness analysis of technological systems of natural gas fired gas-steam combined heat and power (CHP) plants, operating in district heating systems. The analysis was performed for the following technological systems of gas-steam CHP plants: (1) gas-steam CHP plant with two-pressure heat recovery steam generator (HRSG) and extraction-condensing steam turbine, and (2) gas-steam CHP plant with three-pressure HRSG and extraction-condensing steam turbine. For particular kinds of technological systems of gas-steam CHP plants there were determined the following quantities characterizing their energy effectiveness: annual efficiency of electricity produced in cogeneration, annual efficiency of heat produced in cogeneration, annual overall efficiency, power to heat ratio and primary energy savings (PES). In the second part of the paper there is presented the analysis of the following quantities characterizing the economic effectiveness of natural gas fired gas-steam CHP plants: net present value (NPV), internal rate of return (IRR) and unitary electricity generation costs (EGC). The results of performed calculations of these quantities are presented in figures and in table.

Nomenclature

- \( a, b \) – numerical coefficients determining mass fractions of natural gas and oxidizer related to 1 kg of combustion gases
- \( D_{gt} \) – flow rate of combustion gases of gas turbine, kg/s
- \( D_{s1}, D_{s2}, D_{s3} \) – flow rates of high, medium and low pressure steam, kg/s
- \( D_{se1}, D_{se2} \) – flow rates of extraction steam of steam turbine, kg/s
- \( D_c \) – flow rates of steam at the outlet of steam turbine, kg/s
- \( h \) – physical enthalpy of combustion gases, gaseous fuel or air, kJ/kg

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<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$h_{cg1}$, $h_{cg2}$</td>
<td>physical enthalpy of combustion gases at the inlet and at the outlet of gas turbine, kJ/kg</td>
</tr>
<tr>
<td>$h_{cg2}$, $h_{cg10}$</td>
<td>physical enthalpy of combustion gases in particular points of two-pressure HRSG, kJ/kg</td>
</tr>
<tr>
<td>$h_{cg2}$, $h_{cg13}$</td>
<td>physical enthalpy of combustion gases in particular points of three-pressure HRSG, kJ/kg</td>
</tr>
<tr>
<td>$h_{fw11}$, $h_{fw12}$, $h_{fw13}$</td>
<td>enthalpy of high pressure feeding water, kJ/kg</td>
</tr>
<tr>
<td>$h_{fw21}$, $h_{fw22}$, $h_{fw23}$</td>
<td>enthalpy of medium pressure feeding water, kJ/kg</td>
</tr>
<tr>
<td>$h_{fw31}$, $h_{fw32}$</td>
<td>enthalpy of low pressure feeding water, kJ/kg</td>
</tr>
<tr>
<td>$h_{se1}$, $h_{se2}$, $h_c$</td>
<td>enthalpy of extraction and outlet steam of steam turbine, kJ/kg</td>
</tr>
<tr>
<td>$h_{s1}$, $h_{s2}$, $h_{s3}$</td>
<td>HRSG outlet enthalpy of high, medium and low pressure steam, kJ/kg</td>
</tr>
<tr>
<td>$h_{s11}$, $h_{s21}$, $h_{s31}$</td>
<td>steam turbine inlet enthalpy of high, medium and low pressure steam, kJ/kg</td>
</tr>
<tr>
<td>$h_{ss2}$</td>
<td>enthalpy of medium pressure saturated steam, kJ/kg</td>
</tr>
<tr>
<td>$h_{we2}$</td>
<td>enthalpy of condensate in heat exchanger, kJ/kg</td>
</tr>
<tr>
<td>$\Delta_{tpp1}$, $\Delta_{tpp2}$, $\Delta_{tpp3}$</td>
<td>pinch points of high, medium and low pressure parts of HRSG, K</td>
</tr>
<tr>
<td>$H_e$</td>
<td>utilization time of nominal electric power of CHP plant, hours/a</td>
</tr>
<tr>
<td>$H_h$</td>
<td>utilization time of thermal power produced in cogeneration of CHP plant, hours/a</td>
</tr>
<tr>
<td>$\Delta H_i(T_0, T_{cg})$, $\Delta H_i(T_0, T_{g})$, $\Delta H_i(T_0, T_{OX})$</td>
<td>increments of molar physical enthalpy of particular components of combustion gases, gaseous fuel and oxidizer (air) related to the temperature $T_0$, kJ/kmol</td>
</tr>
<tr>
<td>$\Delta H_i(T_0, T)$</td>
<td>increments of molar physical enthalpy of particular components of combustion gases, gaseous fuel or air related to the temperature $T_0$, kJ/kmol</td>
</tr>
<tr>
<td>$\Delta h(T_0, T_{H2O})$</td>
<td>increment of physical enthalpy of water or steam related to the temperature $T_0$, kJ/kg</td>
</tr>
<tr>
<td>$M_i$</td>
<td>molar mass of particular components of combustion gases, gaseous fuel and oxidizer, kg/kmol</td>
</tr>
<tr>
<td>$n$</td>
<td>number of components of combustion gases ($n = 5$, CO$_2$, H$_2$O, O$_2$, N$_2$, Ar), gaseous fuel ($n = 11$), and of air ($n = 3$, O$_2$, N$_2$, Ar)</td>
</tr>
</tbody>
</table>
1 Introduction

One of the important goals of the development of the technology of electricity generation in power plants fired with fossil fuels in 21st century will be decreasing of CO$_2$ emission to the atmosphere. It is justified by the necessity of decreasing of greenhouse gases emission according to the United Nations Framework Convention on Climate Change and from policy of sustainable development of energy systems. This goal may be achieved by increasing the efficiency of power plants fired with coal and by increasing the share of combined heat and power (CHP) plants in electricity generation, and also by partial replacing of coal by other fuels, for example by natural gas or biomass. Use of natural gas in cogeneration of electricity and heat allows one to obtain significant energy and ecological effects. Replacement of coal by natural gas in CHP plants allows one to:

\[ p_{CGI}, p_{GI}, p_{OX} \] – partial pressure of particular component of the combustion gases, gaseous fuel and oxidizer (air)
\[ p_i \] – partial pressure of particular component of the combustion gases or air
\[ P_{igt}, P_{ic} \] – internal power of the gas turbine and the compressor, respectively, kW
\[ P_{elgt}, P_{elst} \] – electric power of the gas and steam turbine generator, respectively, kW
\[ Q_c \] – thermal power in cogeneration of gas-steam CHP block, kW
\[ Q_h^g \] – lower heating value of natural gas kJ/Nm$^3$
\[ Q_{he} \] – heat transferred to water of district heating system in heat exchanger, kW
\[ Q_{HRSG} \] – heat transferred to water of district heating system in HRSG, kW
\[ Q_{wgi} \] – combustion heat of particular components of natural gas, kJ/Nm$^3$
\[ \Delta Q \] – heat losses to the environment, kW
\[ T_{cg}, T_g, T_{ox} \] – temperature of combustion gases, gaseous fuel and oxidizer (air), K
\[ T_o \] – reference temperature (288.15 K)
\[ \eta_{gg} \] – efficiency of gas turbine generator
\[ \eta_{mg} \] – mechanical efficiency of gas turbine
\[ \eta_{gs} \] – efficiency of steam turbine generator
\[ \eta_{ms} \] – mechanical efficiency of steam turbine
• increase the efficiency of generation of electricity and useful heat, and due
to this to increase the effectiveness of utilization of chemical energy of fuel;
• decrease significantly harmful influence of CHP plants on natural environ-
ment, that is to eliminate totally the emission of SO₂ and of dust, and
decrease significantly the emission of CO₂ and of NOx to the atmosphere;
• decrease the investment costs, and decrease the period of construction of
CHP plants.

2 Technological systems of analysed gas-steam CHP
plants
In this paper for comparative analysis of energy and economic effectiveness the
following natural gas fired gas-steam CHP plants were chosen:
• gas-steam CHP plant of electric power of about 100 MW with two-pressure
heat recovery steam generator (HRSG) and extraction-condensing steam
turbine (Fig. 1),
• gas-steam CHP plant of electric power of about 400 MW with three-pressure
HRSG and extraction- condensing steam turbine (Fig. 2).

3 Analysis of energy effectiveness
The performance of energy balances of particular variants of technological sys-
tems of gas-steam CHP plants was the basis of analysis of these systems from
the point of view of energy effectiveness of electricity and of heat produced in
cogeneration. The following quantities characterizing the energy effectiveness of
particular technological systems of analyzed CHP plants were determined [1]:
annual efficiency of electricity produced in cogeneration, annual efficiency of heat
produced in cogeneration, annual overall efficiency, power to heat ratio and pri-
mary energy savings (PES).

The base for calculation of annual production of electricity and heat was
determined by electric power of generators of gas turbines and of steam tur-
bines and thermal power produced in cogeneration and the assumed utilization
of nominal electric power (Hₑ) and thermal power produced in cogeneration (Hₕ)
of CHP plants.
Electric power of the generator of gas turbine was determined with the help of the following formula:

$$P_{el\, gt} = (P_{igt} - P_{ic}) \eta_{mg} \eta_{gg} .$$

(1)

Internal power of gas-turbine was determined with the help of the following formula:

$$P_{igt} = D_{gt} (h_{cg1} - h_{cg2}) .$$

(2)

The solution of equation of energy balance of combustion chamber of gas turbine allow to determine the air consumption of gas turbine and composition of combustion gases necessary for calculation of $P_{ic}$, $h_{cg1}$ and $h_{cg2}$. This equation was
Figure 2. Technological system of gas-steam CHP plant with three-pressure HRSG and extraction-condensing steam turbine.

formulated in the following form:

\[
\frac{1}{\sum_{i=1}^{5} M_i p_{cgi}} \sum_{i=1}^{5} p_{cgi} \Delta H_i(T_o, T_{cg}) - a \frac{1}{\sum_{i=1}^{11} M_i p_{gi}} \sum_{i=1}^{11} p_{gi} (Q_{wgi} + \Delta H_i(T_o, T_g)) \\
- b \frac{1}{\sum_{i=1}^{3} M_i p_{oxy}} \sum_{i=1}^{3} p_{oxy} \Delta H_i(T_o, T_{oxy}) + \Delta Q = 0.
\]  

(3)

High and low pressure steam flow rates, for the technological system of a gas-steam power plant with two-pressure HRSG, were determined as the solution of the following system equations (Fig. 3):

\[
D_{gt} (h_{cg2} - h_{cg4}) - D_{s1} (h_{s1} - h_{fw13}) = 0,
\]  

(4)
High, medium and low pressure steam flow rates, for the technological system of a gas-steam power plant with three-pressure HRSG, were determined as the solution of the following system equations (Fig. 4):
Figure 4. Combustion gases and water (steam) temperature profile of HRSG of gas-steam CHP plant with three-pressure HSRG and extraction-condensing steam turbine.

\[
D_{gt} (h_{cg2} - h_{cg5}) - D_s1 (h_{s1} - h_{fw12}) - D_s2 (h_{s2} - h_{ss2}) = 0 ,
\]

\[
D_{gt} (h_{cg5} - h_{cg7}) - D_s1 (h_{fw12} - h_{fw11}) - D_s2 (h_{ss2} - h_{fw23}) = 0 ,
\]

\[
D_{gt} (h_{cg7} - h_{cg10}) - (D_s1 + D_s2) (h_{fw23} - h_{fw22}) - D_s3 (h_{ss3} - h_{fw32}) = 0 .
\]

Electric power of the generator of steam turbine of gas-steam power plant with three-pressure HRSG was calculated with the help of the following formula:

\[
P_{elst} = (D_s1 h_{s11} + D_s2 h_{s21} + D_s3 h_{s31} - D_{se1} h_{se1} - D_{se2} h_{se2} - D_{chc}) \eta_{ms} \eta_{gs} .
\]
Thermal power produced in cogeneration of gas-steam CHP plants was determined with the help of the formula

\[ Q_c = Q_{he} + Q_{HRSG} , \]  

(11)

where:

\[ Q_{he} = D_{he} (h_{sc2} - h_{we2}) , \]  

(12)

\[ Q_{HRSG} = D_{gt} (h_{cg9} - h_{cg10}) \] for CHP block with two-pressure HRSG  

(13)

\[ Q_{HRSG} = D_{gt} (h_{cg12} - h_{cg13}) \] for CHP block with three-pressure HRSG.  

(14)

Physical enthalpy of combustion gases, gaseous fuel and air were determined with the help of partial pressure and molar physical enthalpy of their components

\[ h = \frac{1}{\sum_{i=1}^{n} M_{i} p_{i}} \sum_{i=1}^{n} p_{i} \Delta H_{i(T_0,T)} . \]  

(15)

The relations describing temperature functions of the increments of molar physical enthalpy of particular components of combustion gases \[ \Delta H_{i(T_0,T_c)} \], gaseous fuel \[ \Delta H_{i(T_0,T_g)} \] and air \[ \Delta H_{i(T_0,T_{0a})} \] have been determined with the help of statistical physics [5].

For calculations of quantities characterizing the energy effectiveness of analysed gas-steam CHP plants the following types of gas turbines were chosen [2]: SGT-1000F for gas-steam CHP block with two-pressure HRSG and SGT5-4000F for gas-steam CHP block with three-pressure HRSG. The following composition of natural gas in calculations was assumed: \[ \text{CH}_4 = 97.4387\% , \text{C}_2\text{H}_6 = 1.045\% , \text{C}_3\text{H}_8 = 0.376\% , \text{C}_4\text{H}_{10} = 0.139\% , \text{C}_5\text{H}_{12} = 0.0203\% , \text{C}_6\text{H}_{14} = 0.021\% , \text{N}_2 = 0.877\% , \text{CO}_2 = 0.066\% , \text{He} = 0.017\% . \] The lower heating value of this gas is \[ Q_g^c = 36133.69 \text{ kJ/Nm}^3. \]

The results of calculations of quantities characterizing the energy effectiveness of gas-steam CHP plants are presented in Tab. 1.

4 Analysis of economic effectiveness

For gas-steam CHP plants, which technological systems are presented in Figs. 1–2 there was performed comparative analysis of their economic effectiveness. The following quantities characterizing the economic effectiveness of particular technological system were assumed:

- net present value (NPV),
Table 1. The results of calculations of quantities characterizing the energy effectiveness of gas-steam CHP plants.

<table>
<thead>
<tr>
<th>Quantity</th>
<th>Quantities for the block with:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>two-pressure HRSG</td>
</tr>
<tr>
<td>Electric power of CHP block during heating season, MW</td>
<td>90.483</td>
</tr>
<tr>
<td>Electric power of CHP block during summer, MW</td>
<td>99.863</td>
</tr>
<tr>
<td>Thermal power in cogeneration of CHP block during heating season, MW</td>
<td>76.929</td>
</tr>
<tr>
<td>Annual production of electricity, GWh</td>
<td>597.849</td>
</tr>
<tr>
<td>Annual production of heat, GWh</td>
<td>338.489</td>
</tr>
<tr>
<td>Annual consumption of fuel chemical energy, GWh</td>
<td>1214.325</td>
</tr>
<tr>
<td>Annual efficiency of electricity generation, %</td>
<td>49.23</td>
</tr>
<tr>
<td>Annual efficiency of heat generation, %</td>
<td>27.87</td>
</tr>
<tr>
<td>Annual overall efficiency of CHP block, % [9]</td>
<td>77.10</td>
</tr>
<tr>
<td>Power to heat ratio [8]</td>
<td>1.551</td>
</tr>
<tr>
<td>Annual production of electricity in cogeneration, GWh [6]</td>
<td>524.996</td>
</tr>
<tr>
<td>Share of annual production of electricity in cogeneration in total annual electricity production, %</td>
<td>87.81</td>
</tr>
<tr>
<td>Electrical efficiency of cogeneration production, % [6]</td>
<td>48.64</td>
</tr>
<tr>
<td>Primary energy savings, PES, % [8]</td>
<td>22.44</td>
</tr>
</tbody>
</table>

- internal rate of return (IRR),
- unitary electricity generation costs (EGC), discounted on 2012 [7].

For performed calculations of these quantities there were assumed data from Tab. 1 and the following entry data:

- the period of plant construction, $T_{e1} = 2$ years,
- the period of plant exploitation, $T_{e2} = 25$ years,
- the time utilization of nominal electric power: $H_e = 6400$ hours/year and thermal power in cogeneration $H_h = 4400$ hours/year,
- sale producer’s price of heat $c_c = 31.56$ PLN/GJ,
- the price of natural gas for gas-steam CHP plant, as a large consumer, $c_g = 38.1$ PLN/GJ,
- discount rate 7.5%.
The results of calculations of quantities characterizing the economic effectiveness of analysed technological systems of gas-steam CHP plants, presented on Figs. 1 and 2, are shown in Figs. 5–8 and in Tab. 2.

Table 2. Electricity generation costs and selling price of electricity.

<table>
<thead>
<tr>
<th>Kind of generation unit</th>
<th>Unitary electricity generation costs, discounted on 2012 [PLN/MWh]</th>
<th>Selling price of electricity with certificate revenue of high efficiency cogeneration (2011) [PLN/MWh]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas-steam CHP block with two-pressure HRSG and extraction-condensing steam turbine without CO₂ emission payment</td>
<td>301</td>
<td>312</td>
</tr>
<tr>
<td>Gas-steam CHP block with two-pressure HRSG and extraction-condensing steam turbine with CO₂ emission payment (160 PLN/tCO₂)</td>
<td>351</td>
<td>312</td>
</tr>
<tr>
<td>Gas-steam CHP block with three-pressure HRSG and extraction-condensing steam turbine without CO₂ emission payment</td>
<td>283</td>
<td>315</td>
</tr>
<tr>
<td>Gas-steam CHP block with three-pressure HRSG and extraction-condensing steam turbine with CO₂ emission payment (160 PLN/tCO₂)</td>
<td>330</td>
<td>315</td>
</tr>
</tbody>
</table>

5 Conclusions

The results of performed calculations of energy and economic effectiveness of chosen technological systems of gas-steam CHP plants allow one to formulate the following conclusions:

1. Both the gas-steam CHP block with three-pressure HRSG and extraction-condensing turbine and the gas-steam CHP block with two-pressure HRSG are characterized by high energy effectiveness, that is, they show high electrical efficiency, overall efficiency and primary energy savings. The former gas-steam CHP block has higher energy effectiveness then the latter gas-steam CHP block (Tab. 1).

2. The gas-steam CHP blocks' energy effectiveness essentially impacts their economic effectiveness [1,3,4]. Therefore, the unitary electricity generation costs of gas-steam CHP blocks with three-pressure HRSG are lower
Figure 5. Dependence of NPV and IRR on electric energy selling price for gas-steam power plant with two-pressure HRSG, for natural gas price of 38.1 PLN/GJ, without CO$_2$ emission payment.

Figure 6. Dependence of NPV and IRR on electric energy selling price for gas-steam CHP plant with two-pressure HRSG for natural gas price of 38.1 PLN/GJ, with CO$_2$ emission payment (160 PLN/tCO$_2$).
Figure 7. Dependence of NPV and IRR on electric energy selling price for gas-steam power plant with three-pressure HRSG for natural gas price of 38.1 PLN/GJ, without CO$_2$ emission payment.

Figure 8. Dependence of NPV and IRR on electric energy selling price for gas-steam power plant with three-pressure HRSG, for natural gas price of 38.1 PLN/GJ, with CO$_2$ emission payment (160 PLN/tCO$_2$).
than the ones of gas-steam CHP block with two-pressure HRSG. The unitary electricity generation costs, discounted for 2012, without CO₂ emission payment, are lower than the selling price of electricity on competitive market with certificate revenue of high efficiency cogeneration (Tab. 2) [9]. Therefore, the construction of gas-steam CHP block fired with natural gas is economically justified, under such conditions.

3. The unitary electricity generation costs, discounted for 2012, after implementation of CO₂ emission payment from 2013, will be higher than the selling price of electricity on competitive market. Therefore to make the construction of gas-steam CHP block fired with natural gas economically justified, after implementation of CO₂ emission payment from 2013, the selling price of electricity on competitive market has to increase.

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References

Efektywność energetyczna i ekonomiczna elektrociepłowni gazowo-parowych opalanych gazem ziemnym

Streszczenie

W pracy przedstawiono analizę efektywności energetycznej i ekonomicznej układów technologicznych elektrociepłowni gazowo-parowych opalanych gazem ziemnym, pracujących w miejskich systemach ciepłowniczych. Analiza była wykonana dla następujących układów technologicznych elektrociepłowni gazowo-parowych: 1) elektrociepłowni gazowo-parowej z dwuciśnieniowym kotłem odzysknicowym i upustowo-kondensacyjną turbiną parową i 2) elektrociepłowni gazowo-parowej z trójciśnieniowym kotłem odzysknicowym i upustowo-kondensacyjną turbiną parową. Dla każdego z tych układów były wyznaczane następujące wielkości, charakteryzujące ich efektywność energetyczną: średnioroczna sprawność wytwarzania energii elektrycznej w skojarzeniu, średnioroczna sprawność wytwarzania ciepła w skojarzeniu, średnioroczna sprawność ogólna elektrociepłowni, wskaźnik skojarzenia oraz oszczędność energii pierwotnej. W drugiej części pracy jest przedstawiona analiza następujących wielkości charakteryzujących efektywność ekonomiczną elektrociepłowni gazowo-parowych opalanych gazem ziemnym: wartości bieżąca netto (ang. net present value – NPV), wewnętrznej stopa zwrotu (ang. internal rate of return – IRR) oraz jednostkowych kosztów wytwarzania energii elektrycznej. Wyniki wykonanych obliczeń tych wielkości są przedstawione na wykresach i w tablicy.