THERMODYNAMIC AND ECONOMIC ANALYSIS OF NUCLEAR POWER UNIT OPERATING IN PARTIAL COGENERATION MODE TO PRODUCE ELECTRICITY AND DISTRICT HEAT

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Abstract
This paper presents the methodology of techno-economic analysis for a nuclear unit operating in partial cogeneration mode and its application for the case study: a nuclear power plant planned in Poland. The research objectives were: to propose EPR, AP1000 and ESBWR nuclear condensing-extraction turbine systems modifications required for operation in cogeneration, to determine optimal heat production and heat transport line (HTL) parameters, to evaluate the technological feasibility of proposed solutions, to analyze profitability and competitiveness of the system versus coal-fired technologies. To adapt nuclear turbine to operation in partial cogeneration mode, the steam must be extracted from low-pressure (LP) section of the turbine and crossover pipe connecting high-pressure (HP) or intermediate-pressure (IP) section with LP section. Thermodynamic analysis proved that the operation of nuclear power plant at peak thermal load up to 250 MW neither requires to change primary cycle arrangements of considered nuclear units nor thermal capacities of nuclear reactors. Total annual costs of nuclear power plant operating in partial cogeneration were the lowest of all considered heat and power options, with all types of reactors, for the emission allowance price of 27 EUR/t $CO_{2\text{-eq}}$. The specific cost of heat from nuclear cogeneration option was 10.3-12.7 EUR/GJ. [1]

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[1] **Nomenclature**
Roman symbols:

A	area of heat exchanger, m^2
C	power to heat ratio
c_f	capacity factor
d	discount rate (cost of capital), yr^{-1}
D	diameter, m
E	electricity production, MWh

e	emission index, t/MWh
f	Darcy friction factor
F	annual fuel consumption, t/yr
h	specific enthalpy, kJ/kg
H	heat production, MWh
I	investment expenditures, EUR
K	annual cost, EUR/yr
k	specific cost, EUR/ specific natural unit
L	length, m
$\dot{m}$	mass flow rate, kg/s
N	number of years the capital is distributed over i.e. depreciation period, plant operation period
n	the number of items
P	electric power, MW
p	pressure, Pa
$\dot{Q}$	thermal power/heat load/heating output, MW
r	annual rate of costs, yr^{-1}
S	construction period, yrs
s	income tax rate
t	temperature
T	time duration, h/period
u	the share of item in total amount
W	lower heating value of fossil fuel (or nuclear fuel burn-up), MWh/t
w	speed of fluid flow, m/s

Greek symbols:

α	the share of point losses in total pressure loss
β	power loss coefficient
γ	the contribution of heat demand to domestic hot water preparation in total NCP thermal load
Δ	loss (of electrical energy, power or pressure)
η	efficiency
κ	heat transfer coefficient, $W/(m^2 \cdot K)$
λ	thermal conductivity, $W/(m \cdot K)$
ρ	density, kg/m^3

Subscripts:

av	*average*
*add_*	additional (power)
amb	ambient (temperature)
c	in full cogeneration mode (theoretical power)
cap	capital
d	day
decom	decommissioning
dh	district heat
el	electricity (costs), electrical (efficiency)
*eq_*	equivalent (technology option)
fix	fixed (costs)
G	generation (of electricity or heat or both)
g	power generator (efficiency)
i	number (index) of the day in the year
in	inlet of feedwater heater
inn	inner (diameter)
inv	investment (expenditures)
j	index of network feedwater heater
l	linear (losses of pressure)

1 Introduction

In view of the recent European Union decarbonization strategy [1], nuclear cogeneration is perceived as a carbon-free option of combined heat and power (CHP) generation. It will also contribute to the reduction of primary energy consumption because its overall efficiency is expected to be greater than the electrical efficiency of a condensing nuclear power plant (NPP), which is usually 33% [2]. In a nuclear power unit, extraction of steam and its use for district heating is possible by turbine system modification. The concept of using NPP to district heat (DH) production was investigated in the 1970s

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m	mechanical (efficiency)
out	outlet of feedwater heater
ppl	pipeline
pump	pumping system in heat transport line
sc	index of the source of capital
T	transmission
tech	technology option
var	variable (costs)
w	water
z	point (of steam cycle)

Acronyms/Abbreviations:

AP1000	Advanced Passive Reactor
AUX	Auxiliary load
CHP	Combined Heat and Power
CRF	Capital Recovery Factor
CPSN	Common Power System Node
DHA	District Heating Area
EPR	(European Pressurized Water/Evolutionary Power) Reactor
EPTL	Electric Power Transmission Line
ESBWR	Economic Simplified Boiling Water Reactor
EUA	European Union emission allowance
FCP	Fossil-fuel-fired Cogeneration Plant
FDHP	Fossil-fuel-fired District Heating Plant
FPP	Fossil-fuel-fired Power Plant
FWH	Feedwater Heater
HP	High Pressure
HTL	Heat Transport Line
IDC	Interest During Construction
IP	Intermediate Pressure
LMTD	Logarithmic Mean Temperature Difference
LP	Low Pressure
NCP	Nuclear Cogeneration Plant
NFH	(District Heating) Network Feedwater Heater
O&M	Operation and Maintenance
PES	Primary Energy Savings
PWR	Pressurized Water Reactor
TM	Turbine Modifications
TTD	Terminal Temperature Difference

and the 1980s. Advanced studies were conducted in Central and Eastern Europe, where either Russian Water-Water Energetic Reactors (VVER) or High Power Channel-type Reactors (RBMK) were operated [3,4]. In addition, Bruce A NPP with Canada Deuterium Uranium (CANDU) reactor, generated electricity, district heat, and process heat. The latter was used for heavy water production [3]. Another example is NPP with Pressurized Water Reactor (PWR) which supplies electric power as well as heat at 120°C to Beznau, Switzerland [5,6]. There were also concept projects, e.g. Loviisa Unit 3 (Finland) which was supposed to supply heat to the Helsinki metropolitan area, located 80 km from the plant. However, this option has not been pursued [7,8]. Renewed interest was recently expressed by Nuclear Energy Agency (NEA) [9,10], who launched a project to assess the role and economics of nuclear cogeneration for a future low-carbon energy system.

Although the instances of nuclear cogeneration for DH production exist, to our best knowledge there are not many previously published scientific papers that concern specifically this subject. Recently, the studies concerning this field of study were conducted in France. Safa [11] presented the rationale of heat recovery from NPP and proposed modification of existing 1300 MW NPP unit by changing low pressure (LP) turbine to expand the steam to the outlet pressure of 0.2 MPa and outlet the temperature of 120°C. Le Pierrés et al. [12] investigated the possibilities of transporting heat from Bugey NPP to the region of Lyon (France). Jasserand and Devezaux de Lavergne [13] assessed the potential of using combined heat and power for district heating in France and discussed the initial concept of the techno-economic model to study nuclear cogeneration projects. Nuclear cogeneration applications in Russia, with VK-300 Boiling Water Reactor (BWR), were presented in [14–16]. Techno-economic aspects of the adaptation of nuclear power plant to cogeneration for district heating were also discussed by authors from Poland i.e. in [17–20]. The feasibility evaluation method for long-distance heat transport from a nuclear power plant to district heating network was developed in [21,22].

Building and designing a nuclear cogeneration plant (NCP), as in this paper the nuclear power plant adapted to operation in partial cogeneration mode is named, requires the analysis of: available nuclear technology options, climate conditions, process heat and district heat peak demand, the costs of both HTL and nuclear turbine adaptation to operation in the cogeneration mode. The literature review showed that only publication [11] covered these aspects, but the emphasis was put on the conversion of a condensing turbine to a back-pressure one and solely a nuclear power unit with Generation II PWR was analyzed. To our best knowledge, none of the research papers presented the method that combines calculations of power, energy and thermodynamic cycle state properties with the computation of annual costs and the cost of heat for CHP system with a nuclear extraction-condensing turbine.

The main contribution of this paper is the methodology of techno-economic analysis of a nuclear power plant adapted to cogeneration for district heating and application of this method for a case study: a planned nuclear power plant in Poland. The methodology was designed for a nuclear power unit adapted to operate in partial cogeneration mode i.e. below maximum technically possible heat recovery, as opposed to the definition of full cogeneration mode, found in [23]. Presented investigations concerned the extraction of steam from a condensing-extraction turbine to achieve heating output equal to a few percent of the nominal thermal power of a nuclear reactor. It was conditioned by peak heat power demand considered in presented case study. Technical analysis involved the calculations of thermodynamic cycle state properties and electric power output of a nuclear unit. Within the scope of the economic analysis, total annual costs of a nuclear power unit, including the costs of its adaptation to operation in partial cogeneration and the costs of HTL, were calculated. Major variables of this combined techno-economic analysis were: peak thermal load of a nuclear power unit; the loss of electric power and electrical energy resulting from district heat generation; primary energy savings; avoided CO_2 emissions; total annual cost of a nuclear power unit operating in partial cogeneration mode; the cost of heat from a nuclear power plant at district heating network supply point. Major research questions to address by this analysis were: 1) Does the adaptation of newly-built power units with EPR, AP1000 and ESBWR reactors to operation in partial cogeneration, i.e. with peak district thermal load of the plant up to 250 MW, require modifications of the primary cycles of nuclear reactors or their thermal capacities or both? 2) Is nuclear power plant adapted to operation in partial cogeneration mode a least-cost option in comparison with coal-fired heat and power systems, both combined and separate, and what are the techno-economic conditions for economic competitiveness of a nuclear cogeneration plant?

The arrangement of this paper is as follows: section 2 presents the method and the data for technical analysis of a nuclear cogeneration plant, including thermodynamic model and case study characteristics; section 3 demonstrates the method and data of cost analysis; section 4 presents and discusses the results of combined thermodynamic and economic analysis and section 5 contains conclusions.

2 Method of thermodynamic analysis and case study characteristics

2.1 Main assumptions and case study characteristics

Heat supply system, considered in this paper, relies on the co-operation of NCP and a district heat peak plant (DHPkP). The latter is located in district heating area (DHA) i.e. the region, covered by district heating network (DHN), receiving heat from NCP. Parallel NCP-DHPkP connection was chosen, due to its advantages in comparison with series connection, e.g. higher values of temperatures in network feedwater heaters (NFH). This choice results in: lower water mass flow rate in HTL, smaller diameters of pipelines, and lower both pumping power and heat losses in HTL, but the higher loss of electric power and electrical energy in NCP, in comparison with series NCP-DHPkP connection. [17,18]

The distance between potential NCP location (Żarnowiec Lakeside) and considered DHA supply point in Gdynia DHN (both locations in Pomeranian Province, Poland) is approximately 45 km. District heat load duration curve (Fig. 1) for a reference case (Table 1) was drawn on the basis of daily average ambient temperatures (Fig. 2), obtained from Weather Underground [24] that contains the collection of data recorded from a weather station located near Gdynia. Peak district heat load ($\dot{Q}_{DHA}$), presented in Fig. 1, corresponds to the actual value in Gdynia DHN. The load of NCP followed the demand of DHN, and maximal considered peak thermal load of NCP was 250 MW. The remaining share was met by DHPkP. Unlike it was proposed in publication [11], in this paper it was assumed that nuclear plant would meet the demand for heat used to prepare domestic hot water throughout the entire time of NCP operation in a year, including the period outside the heating season, but taking into account annual average break for the reactor refueling (see Fig. 1).

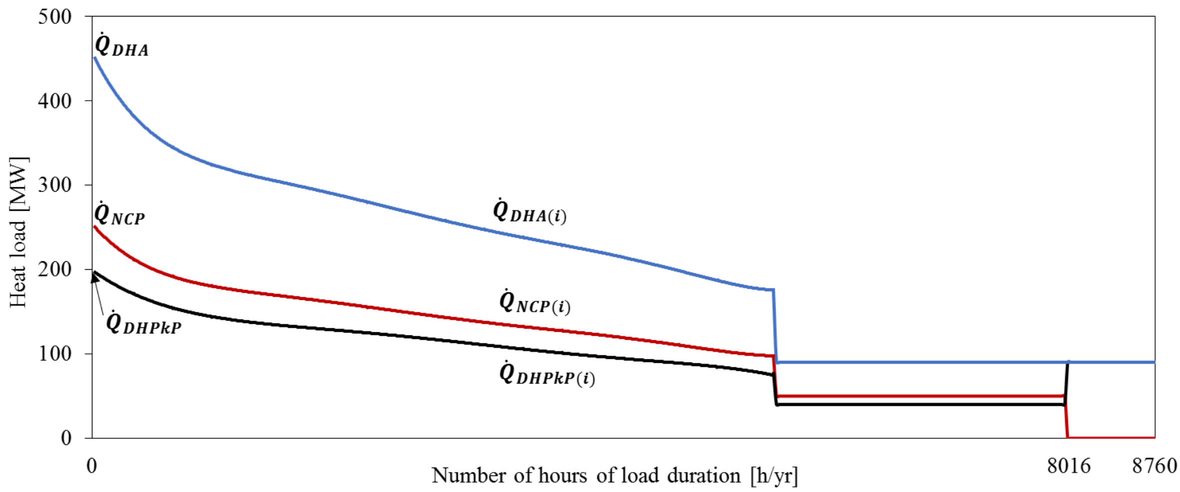

Fig. 1. Annual district heat load duration curve in district heating area $\dot{Q}_{DHA(i)}$, thermal load of nuclear cogeneration plant $\dot{Q}_{NCP(i)}$ and thermal load of district heat peak plant $\dot{Q}_{DHPkP(i)}$ – reference case

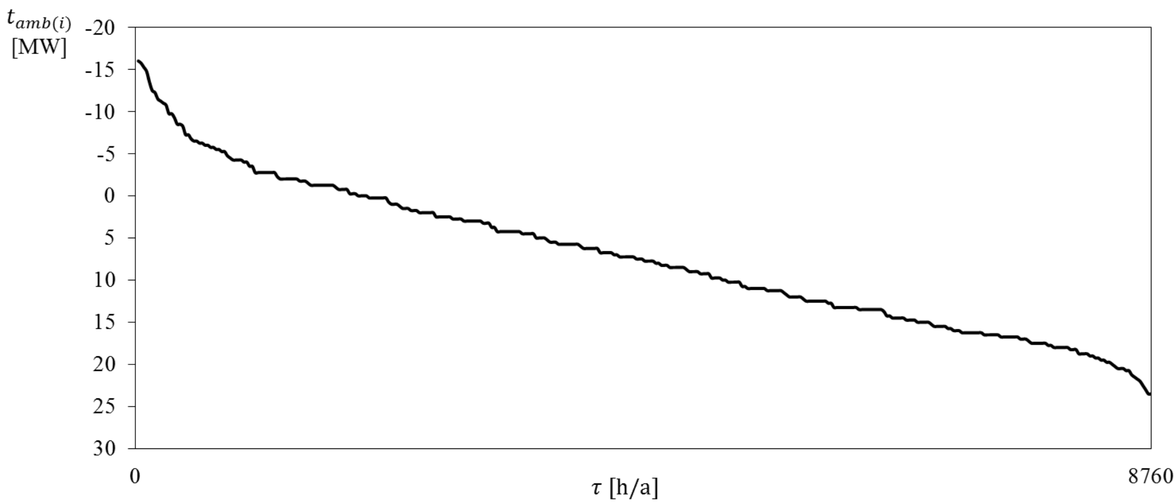

Fig. 2. Duration curve of daily average ambient temperatures $t_{amb(i)}$ (Northern Poland). Authors' illustration based on [24]

2.2 Nuclear power units selection and the concept of turbine modifications

Taking into account the development of nuclear reactor technologies, NPP units with three types of Generation III+ reactors were selected for further analysis i.e.: 1) Evolutionary Power Reactor (EPR), 2) Advanced Passive Reactor (AP1000), and 3) Economic Simplified Boiling Water Reactor (ESBWR). Turbine systems of AP1000 [25], and ESBWR [26] units consist of one high-pressure turbine section and three low-pressure turbine sections, whereas a turbine system in EPR unit [27] consist of one high-pressure (HP), one intermediate-pressure (IP) and three low-pressure (LP) sections. Analyzed peak thermal loads were only a few percent of the nominal thermal capacity of each nuclear reactor (e.g. 3.3-5.6% for EPR). Thus, it was predicted that the reactor primary circuit and the nominal nuclear reactor thermal capacity remain unchanged, and the emphasis was put on the proposal of the turbine system modifications. Then, steam extraction to supply district heat to consumers would result in the reduction of electric power output and electricity generation in NCP and different thermodynamic cycle state properties, as compared to those in condensing NPP. It was also predicted that to adapt considered nuclear turbines to operation in partial cogeneration mode and to meet assumed peak thermal load it is necessary to extract steam not only from low-pressure turbine bleeders, but also from the HP/LP crossover pipe, in two-section turbines (see Fig. 3b-c), or from IP/LP crossover pipe, in three-section turbines (see Fig. 3a) [28,29]. For safety reasons, BWR-type reactors require separate on-site intermediate circuit, as suggested in [30], due to the radioactivity inherently present in the turbine processes in this type of a reactor power unit (see Fig 3c. for ESBWR).

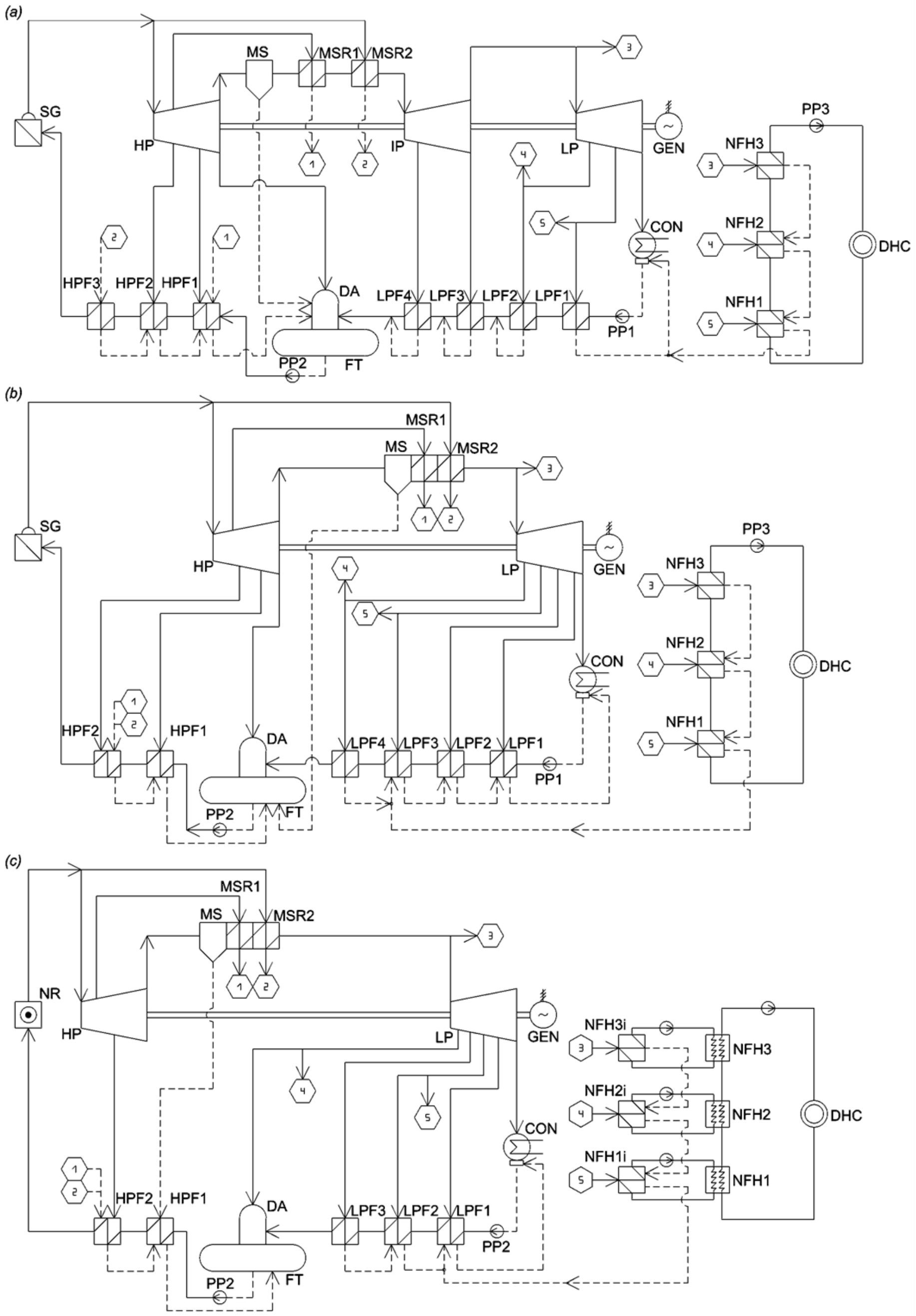

Fig. 3. Schematic diagram of turbine systems adapted to operation in partial cogeneration mode - models for the calculations of thermodynamic cycle state properties, energy balance, and electric power output: (a) EPR, (b) AP1000 and (c) ESBWR, authors' illustration based on [25–27,31]. Note: CON – Condenser; DA – Deaerator; DHC – District Heat Consumers; FT – Feedwater Tank; GEN – Generator; HPF1-3 – High-Pressure Feedwater preheaters; HP, IP, LP – High-, Intermediate-, and Low-Pressure turbine section; LPF1-4 – Low-Pressure Feedwater preheaters; MS – Moisture Separator; MSR1-2 – Main Steam Reheat; NFH1-3 – district heating Network Feedwater Heaters; NFH1-3i – intermediate circuit heat exchangers; NR – Nuclear Reactor vessel; PP1-3 – Pumps; SG – Steam Generator

2.3 Thermodynamic analysis and energy balance of plant

To analyze technical feasibility and economic viability of a nuclear power unit operating in partial cogeneration mode, computations of thermodynamic state properties were performed. Thermodynamic models of turbine systems for EPR (Fig. 3a and Fig. 4), AP1000 (Fig. 3b) and ESBWR (Fig. 3c) units adapted to operation in partial cogeneration, were developed. Each thermodynamic model was a system of thermal and mass balance equations for turbines system components (Fig. 3). Thermodynamic parameters of nuclear turbine systems operating in a condensing mode were obtained from official documents published by Westinghouse [25] and the United States Nuclear Regulatory Commission (US NRC) [26,27,31]. Except for turbine modifications to adapt it to partial cogeneration, several modifications and simplifications of turbine system models presented in [25–27,31] were introduced e.g. author's EPR model was modified in relation to US EPR model obtained from [27] in the following way: 1) three LP turbines were replaced with one; 2) steam pressure in a condenser was set at 6 kPa, instead of 8.57 kPa due to different condenser cooling conditions; 3) feedwater heater efficiency was equal to η_{FWH} = 100% and 4) mass flow rates of steam generator secondary inlet and secondary outlet were adjusted to 2600 kg/s, while in US EPR model they were equal to 2632 and 2606 kg/s, respectively. Balance equations were solved for NPP in both condensing and cogeneration modes for thermal loads changing over the year (as in Fig. 1). The method of thermal balancing of turbine systems was presented e.g. in [32]. To calculate steam properties, X Steam Tables [33] were applied, while Microsoft Excel with Solver was employed to solve the system of equations.

As a result of thermodynamic model application, it was possible to determine daily average values pf electric and thermal power ($P_{NCP(i)}$ and $\dot{Q}_{NCP(i)}$, - see Fig. 6 and Fig. 1, respectively) for different operating states, in both condensing and partial cogeneration mode.

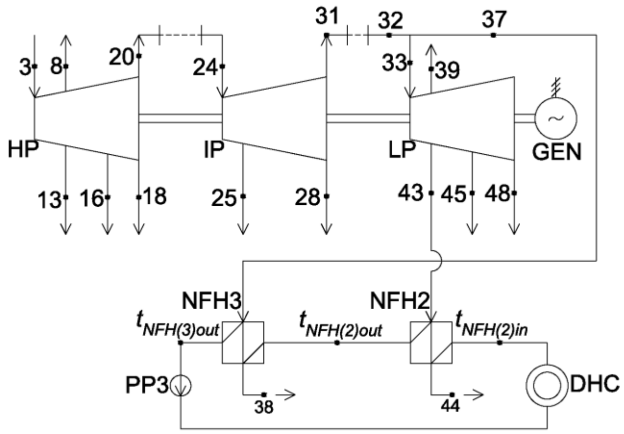

Fig. 4. Simplified authors' model of turbine system and network feedwater heaters for EPR power unit – the reference case

To select optimal parameters of heat production and transport and to study the impact of these parameters on the costs, sensitivity analysis of the thermodynamic model was performed. For each nuclear turbine system, steam extraction to one, two or three network feedwater heaters was considered. Peak thermal load of a nuclear cogeneration plant was set at 150, 200 or 250 MW; network feedwater temperature was set at 110, 120 or 130°C; and the contribution of heat demand to domestic hot water preparation in the total thermal load of NCP was set at 10%, 20% or 30%. The method of optimal selection of these parameters was presented in [34]. Table 1 presents the set of parameters of the reference case, for which the results presented in section 4 were obtained.

Table 1. Key parameters chosen for thermodynamic analysis and energy balance of a plant – the reference case [27,35]

NPP unit parameters	Nuclear power unit		
	EPR	AP1000	ESBWR
Nuclear reactor thermal capacity, MW, $\dot{Q}_{NR}$	4 500	3 415	4 500
Gross electric power output of NPP (in condensing mode), MW, P_{NPP}	1 710	1 200	1 594
Net electric power output of NPP (in condensing mode), MW, $P_{net,NPP}$	1600	1117	1530
Parameters of heat production and transport – reference case	All nuclear power units		
Peak thermal load of NCP, MW, $\dot{Q}_{NCP}$	250		
The number of network feedwater heaters, J	2		
Network feedwater temperature, °C, $t_{NFH(3)out}$	130		

The contribution of heat demand to domestic hot water preparation in total thermal load of NCP, %, γ	20

Electric power of NCP was calculated as the sum of turbine sections contributions ($P_{NCP,HP}$, $P_{NCP,IP}$, $P_{NCP,LP}$), determined using corresponding mass flow rates $\dot{m}_z$ and enthalpies h_z of steam in point z of the steam cycle, and with the use of mechanical (η_m = 0.99) and electrical (η_g = 0.98) efficiencies of the turbine and generator, respectively. For EPR power unit (see Fig. 4 for authors' simplified model of EPR turbine) it was computed as follows:

$$P_{NCP} = P_{NCP,HP} + P_{NCP,IP} + P_{NCP,LP} \tag{1}$$

where:

$$P_{NCP,HP} = [\dot{m}_3 \cdot (h_3 - h_{13}) + (\dot{m}_3 - \dot{m}_{13} - \dot{m}_8) \cdot (h_{13} - h_{16}) + (\dot{m}_3 - \dot{m}_{13} - \dot{m}_8 - \dot{m}_{16}) \cdot (h_{16} - h_{18})] \cdot \eta_m \cdot \eta_g \tag{2}$$

$$P_{NCP,IP} = [\dot{m}_{24} \cdot (h_{24} - h_{25}) + (\dot{m}_{24} - \dot{m}_{25}) \cdot (h_{25} - h_{28})] \cdot \eta_m \cdot \eta_g \tag{3}$$

$$P_{NCP,LP} = [\dot{m}_{33} \cdot (h_{33} - h_{39}) + (\dot{m}_{33} - \dot{m}_{39} - \dot{m}_{43}) \cdot (h_{39} - h_{45}) + (\dot{m}_{33} - \dot{m}_{39} - \dot{m}_{43} - \dot{m}_{45}) \cdot (h_{45} - h_{48})] \cdot \eta_m \cdot \eta_g \tag{4}$$

Additionally, to determine the costs of turbine system modifications (Equation 39), theoretical electric power in full cogeneration ($P_{c,NCP}$) was calculated. It is this part of the electric power of NCP (P_{NCP}) that would be produced by means of expansion of steam that in partial cogeneration mode is supplied to network feedwater heaters only, not taking into account the remainder of steam that flows to the condenser and regenerative preheaters. It reflects the amount of electric power produced in full cogeneration mode with the thermal power of NCP (Q_{NCP}). It was determined as the sum of contributions of steam mass flow rates supplying each network feedwater heater i.e.:

$$P_{c,NCP} = \sum_{j=1}^{J} P_{c,NFH(j)} \tag{5}$$

Where: j and J were the index and the number of network feedwater heaters, respectively. For EPR with J = 2 network feedwater heaters ($P_{c,NFH(1)}$ = 0 MW in Fig. 4) it was determined as follows:

$$P_{c,NCP} = P_{c,NFH(2)} + P_{c,NFH(3)} = [\dot{m}_{43} \cdot (h_3 - h_{20} + h_{24} - h_{31} + h_{33} - h_{39}) + \dot{m}_{37} \cdot (h_3 - h_{20} + h_{24} - h_{31})] \cdot \eta_m \cdot \eta_g \tag{6}$$

Computations performed for the entire spectrum of daily average ambient temperatures and corresponding thermal loads of NCP (Fig. 1 and Fig. 2) were used to determine annual average electric power of NCP (P_{NCP}) and maximal electric power loss ($\Delta P_{max,NCP}$) resulting from steam extraction from the turbine to the network feedwater heaters (NFH) i.e.:

$$\Delta P_{max,NCP} = P_{NPP} - P_{min,NCP} \tag{7}$$

where: P_{NPP} was NPP nominal electric power in condensing mode and $P_{min,NCP}$ was minimal power output of NCP achieved at maximal NCP thermal load ($\dot{Q}_{NCP}$), occurring at the lowest considered ambient temperature ($t_{amb,min}$ = - 16°C in Fig. 4).

Subsequently, annual electricity production in NCP (E_{NCP}) was determined as:

$$E_{NCP} = \sum_{i=1}^{i=365} P_{NCP(i)} \cdot T_d \tag{8}$$

where: $P_{NCP(i)}$ was average electric power generated by NCP in the i^{th} day of the year, obtained through calculations of the turbine system model for daily average ambient temperature changing over the year ($P_{NCP(i)}$) and T_d was duration of the day.

Annual electricity production in NPP in condensing mode (E_{NPP}) was obtained using capacity factor c_f = 0.915, which corresponds to the average value achieved by nuclear reactors in the United States [36].

The annual electricity loss (ΔE_{NCP}) resulting from steam extraction from the turbine to district heating was determined as follows:

$$\Delta E_{NCP} = E_{NPP} - E_{NCP} \tag{9}$$

For annual cost comparison, it was necessary to determine annual delivery of electricity to a common power system node (E_{CPSN}, for CPSN see fig. 5) which takes into account auxiliary electricity consumption by NCP ($E_{AUX,NCP}$) including electricity consumption for hot water pumping through HTL (E_{pump}):

$$E_{CPSN} = E_{NCP} - E_{AUX,NCP} = E_{NCP} - \left(\frac{P_{NPP} - P_{net,NPP}}{P_{NPP}} \cdot E_{NCP} + E_{pump}\right) \tag{10}$$

Where: P_{NPP} and $P_{net,NPP}$ were gross and net electric power outputs of NPP, respectively.

Similarly to electricity production in NCP, annual heat production (H_{NCP}) was calculated using daily average thermal loads of NCP ($\dot{Q}_{NCP(i)}$):

$$H_{NCP} = \sum_{i=1}^{i=365} \dot{Q}_{NCP(i)} \cdot T_d \tag{11}$$

To evaluate energy and environmental effects of nuclear cogeneration, additional indices and values were calculated. The amount of avoided CO_2 emissions (EM_{CO2}) was obtained as the sum of CO_2 emissions from separate electricity and district heat generation systems including an equivalent fossil-fired power plant (eq_FPP) and an equivalent fossil-fired district heating plant (eq_FDHP), such that:

$$E_{eq\_FPP} = E_{NCP} \tag{12}$$

$$P_{eq\_FPP} = P_{NCP} \tag{13}$$

$$H_{eq\_FDHP} = H_{NCP} \tag{14}$$

$$Q_{eq\_FDHP} = Q_{NCP} \tag{15}$$

Primary energy savings (PES) were calculated using the method presented in [23], whereas the overall efficiencies for NPP in condensing mode (η_{NPP}) and for NCP (η_{NCP}) were determined as:

$$\eta_{NPP} = \frac{P_{NPP}}{\dot{Q}_{NR}} \tag{16}$$

$$\eta_{NCP} = \frac{P_{NCP}+\dot{Q}_{NCP}}{\dot{Q}_{NR}} \tag{17}$$

Power to heat ratio (C) was an annual electricity divided by annual heat production, and power loss coefficient (b) was the fraction of electricity lost to obtained heat:

$$C = \frac{E_{NCP}}{H_{NCP}} \tag{18}$$

$$b = \frac{\Delta E_{NCP}}{H_{NCP}} \tag{19}$$

Results were discussed in section 4 in Table 5.

3 Methods of economic analysis

Economic analysis was performed to prove the competitiveness of a nuclear power plant operating in the cogeneration mode versus fossil-fueled technologies generating electricity or heat or both and delivering them to balance nodes established separately for electricity and heat. Two methods of economic analysis were applied i.e. comparison of total annual costs and the cost of heat.

3.1 Total annual costs

Total annual costs of generation and transmission of electricity or heat or both were calculated and compared for the following heat and power system options:

- combined heat and power system of a nuclear power plant operating in the cogeneration mode – nuclear cogeneration plant (NCP) (Fig. 5 - option a);
- combined heat and power system of an equivalent fossil-fueled cogeneration plant with a back-pressure turbine (eq_FCP) and an additional fossil-fueled power plant (add_FPP) to compensate the difference in electrical outputs of NCP and eq_FCP[2] (Fig. 5 - option b);
- separate heat and power system of an equivalent fossil-fueled power plant (eq_FPP) and an equivalent fossil-fueled district heating plant (eq_FDHP) (Fig. 5 - option c);
- separate heat and power system of an equivalent nuclear power plant (eq_NPP) and eq_FDHP (Fig. 5 - option d).

Annual costs were compared independently for each reactor technology (EPR, AP1000 and ESBWR), due to their different nominal electric power and annual electricity production levels. For each reactor technology, all heat and power system options (a-d) were equivalent from the point of view of net annual electricity and net heat production, as well as electric and thermal power output. Auxiliary electricity consumption (AUX in Fig. 5) by all electricity generating plants was taken into account. The losses of electric power delivered via electric power transmission line (EPTL in Fig. 5) to the common power system node (CPSN) and the losses of heat delivered via HTL to district heating area (DHA) were not accounted in the energy balance. Instead of this, their costs were taken into account in both total annual sum of costs and the cost of heat. Therefore, thermal power and annual heat delivered to DHA by competing heat and power system options (a-d) were equal to those for NCP and these were determined as:

$$Q_{NCP} = Q_{DHA} - Q_{DHPkP} \tag{20}$$

$$H_{NCP} = H_{DHA} - H_{DHPkP} \tag{21}$$

Where: Q_{DHA}, H_{DHA} were peak thermal load and annual heat demand in DHA, respectively, and Q_{DHPkP}, H_{DHPkP} were peak thermal power and annual heat production from DHPkP, respectively. Thermal loads

[2] Power to heat ratio for a back-pressure-turbine fossil cogeneration plant (FCP) is approximately. 0.49 MW/MW, whereas for NPP operated in the cogeneration mode it equals to approximately 6.7 MW/MW (calculated using nominal electrical and peak thermal power loads). If we assume that heat loads of both systems are equal, then NCP electric power output is approximately 14 times greater than for FCP. Therefore, electric power compensating this difference is needed to achieve equal power outputs for both options.

of competing heat and power systems (a-d) followed heat load duration curve in DHA. Heat and power systems compared with NCP (options b-d) met thermal load according to the same pattern as NCP (see Fig. 1), whereas heat demand in DHA was balanced by a peak load plant (see DHPkP in Fig. 5), which was common for all a-d options. Therefore, the costs of DHPkP were not accounted in the economic analysis. Similarly, power and electricity production in mid-merit (load-following) and peak power plants and their costs were not included in the analysis.

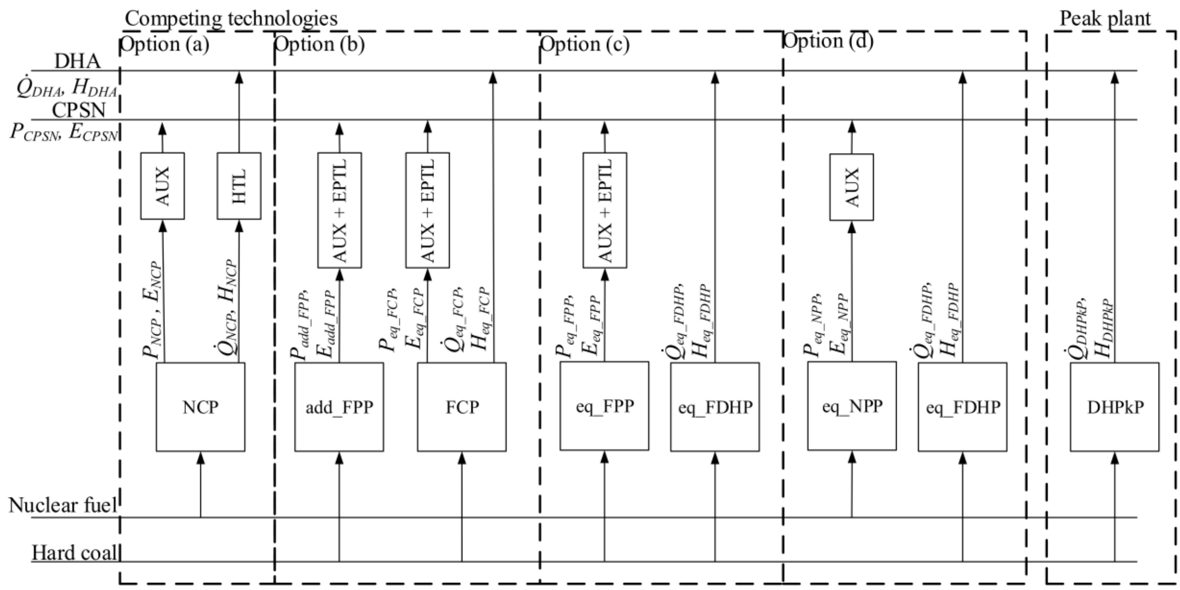

Fig. 5. Reference energy system for total annual cost comparative analysis. Note: AUX – Auxiliary load; CPSN – Common Power System Node; EPTL – Electric Power Transmission Line; HTL – Heat Transport Line

NCP (option a) is competitive, if its total annual costs (K_a) are lower than the annual costs of alternative equivalent heat and power system options (K_b, K_c and K_d), compared for the same reactor type [19] i.e.:

$$K_a < K_b \wedge K_a < K_c \wedge K_a < K_d \tag{22}$$

Total annual costs were calculated using generic method taking into account the costs of generation (G) and transmission (T) of electricity (el) and district heat (dh) to CPSN and DHA, respectively, from competing heat and power technology combinations (*tech* i.e. options a-d in Fig. 5):

$$K_a = K_{G+T,el+dh,NCP} \tag{23}$$

$$K_b = K_{G+T,el+dh,eq\_FCP+add\_FPP} = K_{G+T,el+dh,eq\_FCP} + K_{G+T,el,add\_FPP} \tag{24}$$

$$K_c = K_{G+T,el+dh,eq\_FPP+eq\_FDHP} = K_{G+T,el,eq\_FPP} + K_{G,dh,eq\_FDHP} \tag{25}$$

$$K_d = K_{G+T,el+dh,eq\_NPP+eq\_FDHP} = K_{G,el,eq\_NPP} + K_{G,dh,eq\_FDHP} \tag{26}$$

The costs of electricity and heat production were calculated as the sum of costs of capital, O&M, fuel, decommissioning and emission allowances (EUA), respectively:

$$K_{G,el+dh,tech} = K_{G,tech,cap} + K_{G,tech,O\&M} + K_{G,tech,fuel} + K_{G,tech,decom} + \mathrm{K}_{G,tech,EUA} \tag{27}$$

and the costs of transmission of electricity were based on the amount of gross electric power of technology (P_{tech}) and electrical energy generated annually (E_{tech}):

$$K_{T,el,tech} = k_{T,el,tech,fix} \cdot P_{tech} + k_{T,el,tech,var} \cdot E_{tech} \quad . \tag{28}$$

Annualized capital costs of heat and power generation ($K_{G,tech,cap}$) were obtained using a capital recovery factor (CRF - $r_{G,tech,CRF}$) and an interest rate during construction (IDC - $r_{G,tech,IDC}$). The former assumed equal amount of capital cost ($K_{G,tech,cap}$) over the entire operation time ($N_{G,tech}$), while the latter even distribution of investment expenditures ($I_{G,tech}$) over the construction period ($S_{G,tech}$):

$$K_{G,tech,cap} = r_{G,tech,\mathrm{CRF}} \cdot (1 + r_{G,tech,IDC}) \cdot I_{G,tech} =$$

$$= \frac{d_{G,tech} \cdot (1+d_{G,tech})^{N_{G,tech}}}{(1+d_{G,tech})^{N_{G,tech}}-1} \cdot \frac{(1+d_{G,tech})^{S_{G,tech}}-1}{S_{G,tech} \cdot d_{G,tech}} \cdot I_{G,tech} \tag{29}$$

Discount rate of each technology option ($d_{G,tech}$) was determined as the weighted average cost of capital (WACC), including own capital (*sc1*) and bank loan (*sc2*). The latter also took into account income tax rate (s_{tax}):

$$d_{G,tech} = u_{sc1} \cdot d_{G,tech,sc1} + u_{sc2} \cdot d_{G,tech,sc2} \cdot (1 - s_{tax}) \tag{30}$$

Investment expenditures were based on specific investment cost ($k_{G,tech,inv}$) and either gross electric power of technology (P_{tech}) or maximum available thermal power ($\dot{Q}_{tech}$). The former was used for power plants and cogeneration plants, while the latter for plants generating district heat only:

$$I_{G,tech} = k_{G,tech,inv} \cdot P_{tech} \text{ or } I_{G,tech} = k_{G,tech,inv} \cdot \dot{Q}_{tech} \tag{31}$$

Similarly, operation and maintenance (*O&M*) costs, fuel costs, decommissioning costs and emission allowances costs were obtained with the use of annual electricity or annual heat production. Annual O&M costs were obtained as:

$$K_{G,tech,O\&M} = k_{G,tech,O\&M} \cdot E_{tech} \text{ or } K_{G,tech,O\&M} = k_{G,tech,O\&M} \cdot H_{tech} \tag{32}$$

Fuel costs, based on its price ($k_{G,tech,fuel}$) were determined as follows:

$$K_{G,tech,fuel} = k_{G,tech,fuel} \cdot F_{tech} \tag{33}$$

where annual fuel consumption was obtained using annual electricity or heat production, lower fuel heating value or nuclear fuel burn-up and electrical and thermal efficiencies, respectively:

$$F_{tech} = \frac{E_{tech}}{\eta_{el} \cdot W_{fuel,tech}} \text{ or } F_{tech} = \frac{H_{tech}}{\eta_{dh} \cdot W_{fuel,tech}} \tag{34}$$

Decommissioning costs were determined in a similar manner as O&M costs, but with the use of specific decommissioning cost ($k_{G,tech,decom}$) i.e.:

$$K_{G,tech,decom} = k_{G,tech,decom} \cdot E_{tech} \text{ or } K_{G,tech,decom} = k_{G,tech,decom} \cdot H_{tech} \tag{35}$$

Carbon dioxide (CO_2) emission allowances (EUA) costs were computed as follows:

$$K_{G,tech,EUA} = k_{EUA} \cdot e_{G,tech,CO_2} \cdot E_{tech} \cdot \eta_{el,tech}^{-1}$$

$$\text{or } K_{G,tech,EUA} = k_{EUA} \cdot e_{G,tech,CO_2} \cdot H_{tech} \cdot \eta_{dh,tech}^{-1} \tag{36}$$

where: $e_{G,tech,CO_2}$ was emission per energy input factor, $\eta_{el,tech}$, $\eta_{dh,tech}$ were the efficiencies of electricity and district heat production, respectively, k_{EUA} was EUA price average over the entire plant lifetime. Key economic parameters of technology types were presented in Table 2. Construction time was equal to $S_{G,tech}$ = 4 yrs for fossil-fired plants [37] and $S_{G,tech}$ = 8 yrs for nuclear plants [38]. The shares of own capital and bank loan amounted to u_{sc1} = 20% and u_{sc2} = 80%, respectively. The cost (interest rate) of own capital and bank loan equaled to $d_{G,tech,sc1}$ = 0.10 yr^{-1} and $d_{G,tech,sc2}$ = 0.05 yr^{-1}, respectively. Income tax rate was set at s_{tax} = 19% [38]. The average emission allowance (EUA) price was assumed to be k_{EUA} = 20 EUR/t $CO_{2\text{-}eq}$ on the basis of the price projections from [39,40]. It was also assumed that fossil-fueled power plants (eq_FPP and add_FPP) operated in a location which is remote from CPSN, i.e. in Central or Southern Poland. Therefore, fixed ($k_{T,el,tech,fix}$ = 32 900 EUR/MW/yr) and variable ($k_{T,el,tech,var}$ = 44.28 EUR/MWh) [41] costs of electricity transmission were taken into account for these technologies.

Table 2. Economic parameters of each technology type – the reference case [35,42–48]. Note: eq_FCP – equivalent Fossil-fueled Cogeneration Plant; add_FPP - additional electric power from Fossil-fueled Power Plant; eq_FPP - equivalent Fossil-fueled Power Plant; eq_FDHP - equivalent Fossil-fueled District Heating Plant; NCP – Nuclear Cogeneration Plant; eq_NPP – equivalent Nuclear Power Plant

<table>
<tr><th rowspan="2">Parameter</th><th colspan="6">Technology type</th></tr>
<tr><th>eq_FCP</th><th>add_FPP | eq_FPP</th><th>eq_FDHP</th><th colspan="3">NCP | eq_NPP</th></tr>
<tr><td>Number of years the source of capital is distributed over (own capital and bank loan), $N_{G,tech,sc}$</td><td>25</td><td>50</td><td>25</td><td colspan="3">60</td></tr>
<tr><td rowspan="3">Specific investment cost (not including adaptation to cogeneration), EUR/kW, $k_{G,tech,inv}$</td><td rowspan="3">2 046</td><td rowspan="3">1 431</td><td rowspan="3">250</td><td>EPR</td><td>3 760</td><td>3 711</td></tr>
<tr><td>AP1000</td><td>4 111</td><td>4 005</td></tr>
<tr><td>ESBWR</td><td>3 256</td><td>3 184</td></tr>
<tr><td rowspan="3">Specific annual O&M costs (not including adaptation to cogeneration), EUR/MWh, $k_{G,tech,O\&M}$</td><td rowspan="3">9.49</td><td rowspan="3">3.75</td><td rowspan="3">17.01</td><td>EPR</td><td>18.76</td><td>18.52</td></tr>
<tr><td>AP1000</td><td>15.38</td><td>14.99</td></tr>
<tr><td>ESBWR</td><td>8.12</td><td>7.94</td></tr>
<tr><td rowspan="3">Specific decommissioning cost, EUR/MWh, $k_{G,tech,decom}$</td><td rowspan="3">0.09</td><td rowspan="3">0.07</td><td rowspan="3">0.00</td><td>EPR</td><td colspan="2">0.17</td></tr>
<tr><td>AP1000</td><td colspan="2">0.16</td></tr>
<tr><td>ESBWR</td><td colspan="2">0.10</td></tr>
<tr><td rowspan="3">Specific fuel cycle costs, EUR/t, $k_{G,tech,fuel}$</td><td rowspan="3">96.15</td><td rowspan="3">96.15</td><td rowspan="3">96.15</td><td>EPR</td><td colspan="2">773 498</td></tr>
<tr><td>AP1000</td><td colspan="2">773 498</td></tr>
<tr><td>ESBWR</td><td colspan="2">773 498</td></tr>
<tr><td rowspan="3">Fossil fuel lower heating value (or nuclear fuel burnup), MWh/t, $W_{fuel,tech}$</td><td rowspan="3">75 600</td><td rowspan="3">75 600</td><td rowspan="3">75 600</td><td>EPR</td><td colspan="2">1 080 000</td></tr>
<tr><td>AP1000</td><td colspan="2">1 272 000</td></tr>
<tr><td>ESBWR</td><td colspan="2">1 008 000</td></tr>
<tr><td rowspan="3">Gross efficiency of technology tech, %, power plants and cogeneration plants - $\eta_{el,tech}$, district heating plants - $\eta_{dh,tech}$</td><td rowspan="3">0.30</td><td rowspan="3">0.45</td><td rowspan="3">0.80</td><td>EPR</td><td>0.373</td><td>0.378</td></tr>
<tr><td>AP1000</td><td>0.342</td><td>0.351</td></tr>
<tr><td>ESBWR</td><td>0.346</td><td>0.354</td></tr>
<tr><td>CO_2 emission index (per unit of input fuel), t/MWh, $e_{G,tech,CO2}$</td><td>0.32</td><td>0.32</td><td>0.49</td><td colspan="3">0.00</td></tr>
</table>

Special emphasis was put on the calculation of the costs of electricity and heat generation in NCP and heat transport from the plant to DHA. They were determined as follows:

$$K_{G+T,el+dh,NCP} = K_{G,el,NCP} + K_{G,dh,NCP} + K_{T,dh,NCP} \quad (37)$$

where: $K_{G,el,NCP}$ were the costs of electricity production in a nuclear power plant operating in the cogeneration mode, $K_{G,dh,NCP}$ were the costs of nuclear turbine adaptation to cogeneration, and $K_{T,dh,NCP}$ were the costs of heat transport from NCP to DHA. The costs of electrical energy losses, resulting from the loss of mechanical energy in turbine due to the extraction of steam to network feedwater heaters, were not included in the annual costs of heat production in NCP. This is because electrical energy is converted into heat, which constitutes a benefit for a plant and the comparative cost analysis takes into account the production of both electrical energy and heat, from competing heat and power system options (a-d). Conversely, the costs of lost electricity and electric power were taken into account in the calculations of specific costs of heat (Equations 54-58), because electricity production and its cost were not accounted in this calculation. The costs of nuclear turbine conversion to cogeneration were the sum of fixed costs of turbine modifications (TM) and network feedwater heaters (NFH), including both annualized capital and fixed O&M costs. These costs were obtained as the product of investment expenditures (I) and the annual rate of fixed costs (r), taking into account CRF and the annual rate of fixed O&M costs, i.e.:

$$K_{G,dh,NCP} = K_{NCP,TM,fix} + K_{NCP,NFH,fix} = r_{NCP,TM,fix} \cdot I_{NCP,TM} + r_{NCP,NFH,fix} \cdot I_{NCP,NFH} \quad (38)$$

Investment in nuclear turbine adaptation to operation in the cogeneration mode was computed as the product of theoretical electric power in full cogeneration ($P_{c,NCP}$) and specific investment cost of turbine modifications ($k_{NCP,TM,inv}$). The former was computed on the basis of equations 5-6, while the latter was obtained empirically on the basis of the number of network feedwater heaters (J) and the specific investment cost of a nuclear power plant operating in condensing mode ($k_{G,eq\_NPP,inv}$):

$$I_{NCP,TM} = k_{NCP,TM,inv} \cdot P_{c,NCP} = \frac{2 \cdot J}{1+J} \cdot 0.01 \cdot k_{G,eq\_NPP,inv} \cdot P_{c,NCP} \quad (39)$$

Investment costs of network feedwater heaters, pipelines and all equipment necessary to extract heat to district heating were calculated as:

$$I_{NCP,NFH} = k_{G,NFH,inv} \cdot \sum_{j=1}^{J} A_{NFH(j)} = k_{G,NFH,inv} \cdot \sum_{j=1}^{J} \frac{\dot{Q}_{NFH(j)}}{\kappa \cdot LMTD_{(j)}} \quad (40)$$

where $k_{G,NFH,inv}$ was specific investment cost of NFH, $A_{NFH(j)}$ was the heat exchange area of j^{th} NFH, $\dot{Q}_{NFH(j)}$ was maximal thermal power exchanged by j^{th} NFH, $LMTD_{(j)}$ was the logarithmic mean temperature difference of j^{th} NFH, and κ was heat transfer coefficient. Maximal thermal power exchanged by NFH was the product of network feedwater mass flow rate during the heating season ($\dot{m}_{NFH}$) and the difference between outlet and inlet enthalpies, respectively, of j^{th} NFH at peak thermal load:

$$\dot{Q}_{NFH(j)} = \dot{m}_{NFH} \cdot (h_{NFH(j)out} - h_{NFH(j)in}) \quad (41)$$

Logarithmic mean temperature difference of j^{th} NFH was determined as:

$$LMTD_{(j)} = \frac{t_{NFH(j)out} - t_{NFH(j)in}}{\ln(\frac{t_{NFH(j)out} - t_{NFH(j)in}}{TTD_{(j)}} + 1)} \quad (42)$$

where $t_{NFH(j)out}$, $t_{NFH(j)in}$, were outlet and inlet temperatures of water flowing through j^{th} NFH, respectively, and $TTD_{(j)}$ was terminal temperature difference at j^{th} NFH. The network feedwater mass flow rate during heating season was determined as follows:

$$\dot{m}_{NFH} = \frac{\dot{Q}_{NCP}}{h_{NFH(3)out} - h_{NFH(1)in}} \tag{43}$$

Parameters of cost calculation of the adaptation of a nuclear power unit to operation in the cogeneration mode were presented in Table 3.

Table 3. Parameters of cost calculation of a nuclear turbine modifications and network feedwater heaters – the reference case [49,50]

Parameter	Reactor technology type		
	EPR	AP1000	ESBWR
Annual rate of fixed costs for nuclear turbine modifications, yr^{-1}, $r_{NCP,TM,fix}$	0.1062	0.0962	0.0862
Annual rate of fixed costs of NFH, yr^{-1}, $r_{NCP,NFH,fix}$	0.1062	0.0962	0.0862
Parameter	All reactor technologies		
Specific investment cost of NFH, EUR/m^2, $k_{G,NFH,inv}$	1 202		
Heat transfer coefficient, kW/(m^2K), κ	5		
Temperature of water at NFH inlet (supply), °C, $t_{supply} = t_{NFH(1)in}$	65.0		
Temperature of water at NFH outlet (return), °C, $t_{return} = t_{NFH(3)out}$	130.0		

Heat transport costs were taken into account only for NCP, as it was assumed that fossil-fueled heat generating technologies (in combined options b-d) were located within the borders of considered DHA. These costs were determined as follows:

$$K_{T,dh,NCP} = K_{HTL,fix} + K_{pump,fix} + K_{pump,var} + K_{\Delta H} \tag{44}$$

where: $K_{HTL,fix}$ were fixed costs of heat transport line, $K_{pump,fix}$ and $K_{pump,var}$ were fixed and variable costs of water pumping, respectively, and $K_{\Delta H}$ were the costs of heat losses.

Fixed costs of heat transport line, including annualized capital and O&M costs, were assumed to take into account series effect in the computation of the investment in HTL pipelines:

$$K_{HTL,fix} = r_{HTL,fix} \cdot I_{T,ppl} = r_{HTL,fix} \cdot 10 \cdot \frac{n_{ppl}}{9+n_{ppl}} \cdot k_{T,ppl,inv} \cdot L_{HTL} \tag{45}$$

where: $r_{HTL,fix}$ was the annual rate of fixed heat transport line costs, $I_{T,ppl}$ were investment expenditures in heat transport pipelines, n_{ppl} was the number of heat transport pipelines, $k_{T,ppl,inv}$ was the specific investment cost of a single heat transport pipeline, and L_{HTL} was heat transport line length.

The specific investment cost of a single heat transport pipeline was determined using trend curve obtained on the basis of district heating investment cost data from [51]. This trend was determined as:

$$k_{T,ppl,inv} = 2913.2 \cdot D_{inn}^2 + 9578.8 \cdot D_{inn} + 1492.9 \tag{46}$$

and the inner diameter of a single pipeline was obtained as follows:

$$D_{inn} = 2 \cdot \sqrt{\frac{\dot{m}_{NFH}}{\pi \cdot n_{ppl} \cdot w_w \cdot \rho_w}} \tag{47}$$

where: w_w and ρ_w were the velocity and the density of water flowing through a heat transport line, respectively.

Fixed costs of pumping hot water through a heat transport line were determined as:

$$K_{pump,fix} = r_{pump,fix} \cdot I_{T,pump} = r_{pump,fix} \cdot k_{T,pump,inv} \cdot n_{ppl} \cdot P_{pump} \tag{48}$$

where: $r_{pump,fix}$ was the annual rate of fixed water pumping costs, $k_{T,pump,inv}$ was the specific investment cost of pumps installed along with a heat transport line and P_{pump} was peak electric power of pump drives installed for hot water transport over HTL. The specific investment cost of HTL pumps was assumed to be a fraction of the specific investment cost of an equivalent nuclear power plant ($k_{G,eq\_NPP,inv}$), and this fraction was dependent on the location of a pump station i.e. at NCP site or in separate buildings along the route of HTL, respectively:

$$k_{T,pump,inv} = 0.07 \cdot k_{G,eq\_NPP,inv} \text{ or } k_{T,pump,inv} = 0.09 \cdot k_{G,eq\_NPP,inv} \tag{49}$$

Peak electric power of HTL pumps electric drives was determined for network feedwater mass flow rate during the heating season ($\dot{m}_{NFH}$, equation 43). It was formulated as follows [52,53]:

$$P_{pump} = \dot{m}_{NFH} \cdot \frac{\Delta p_{HTL}}{\rho_w \cdot \eta_{pump} \cdot \eta_{drv}} = \dot{m}_{NFH} \cdot \frac{\Delta p_l}{\rho_w \cdot (1-\alpha)\eta_{pump} \cdot \eta_{drv}} \tag{50}$$

where: Δp_{HTL} was HTL pump head, taking into account linear pressure losses Δp_l and point losses, expressed as the fraction α of total pressure loss, η_{pump}, η_{drv} were the efficiencies of the pump and the pump drive, respectively. Linear pressure losses in HTL were calculated using Darcy-Weisbach equation [52,53]:

$$\Delta p_l = 0.81 \cdot f \cdot L_{HTL} \cdot \frac{\dot{m}_{NFH}^2}{\rho_w \cdot D_{inn}^5} \tag{51}$$

where: f was Darcy friction factor. Variable costs of pumping were computed as the product of electricity consumption by pump drives E_{pump} and the cost of electricity consumed $k_{el,pump}$ i.e.:

$$K_{pump,var} = k_{el,pump} \cdot E_{pump} = k_{el,pump} \cdot T_d \cdot \sum_{i=1}^{i=365} P_{pump(i)} \tag{52}$$

where $P_{pump(i)}$ was average electric power load of HTL pumps in the i^{th} day of the year.

Parameters of cost calculations of the network water pumping system were presented in Table 4.

Table 4. Parameters of cost calculation of the heat transport network water pumping system, authors' illustration based on [52,53]

Parameter	All reactor types
Annual rate of fixed costs for a heat transport line, yr^{-1}, $r_{T,HTL,fix}$	0.1330
Number of HTL supply pipelines, n_{ppl}	1
Inner diameter of HTL pipeline, mm, D_{inn}	800
Velocity of water flow, m/s, w_w	2
Water density, kg/m^3, ρ_w	960
Annual rate of fixed costs for network water pumping systems, yr^{-1}, $r_{pump,fix}$	0.1258
HTL pumps efficiency, η_{pump}	0.81
HTL pump drives efficiency, η_{drv}	0.85
The share of point losses in total pressure loss, α	10%
Darcy friction factor, f	0.0150
The cost of electricity for pumping (auxiliary load), EUR/MWh, $k_{el,pump}$	48

Annual costs of heat losses were calculated as follows:

$$K_{\Delta H} = k_{dh} \cdot \Delta H_{HTL} \tag{53}$$

where k_{dh} = 35 EUR/MWh was the price of heat in DHA and ΔH_{HTL} was annual heat losses in HTL. Heat losses in HTL were computed separately for summer season (*hs* subscript) and heating season (*ht*) using the methodology presented in [52,53]. A single heat supply line (n_{ppl}, Table 4) and a single return pipeline were designed for heat transport, each having inner diameter D_{inn} (Table 4). Insulation thickness was δ = 0.1 m and its thermal conductivity was λ = 0.03 W/(m·K). Pipelines were assumed to be buried in the ground at the depth of 1.5 m and spaced from each other by 0.3 m. Thermal resistance of insulation and of the ground and the coefficient of thermal interaction between the two pipelines were calculated. The temperature of the ground in heating season was assumed to be 6°C, whereas in summer season it was 15°C. The average values of the losses of thermal power per unit of the pipeline length were computed and they were as follows: $\dot{q}_{HTL,supply,ht}$ = 117.8 W/m, $\dot{q}_{HTL,return,ht}$ = 52.3 W/m, $\dot{q}_{HTL,supply,hs}$ = 83.9 W/m, and $\dot{q}_{HTL,return,hs}$ = 49.9 W/m for the supply and return pipe, for heating and summer season, respectively. They were determined using the coefficients of local heat losses β_1 = 1.5, accounting for the lay of the land along the HTL, and additional heat losses β_2 = 1.25, which take into account the thermal instability of HTL [53]. On this basis, average thermal power losses were computed as: $\Delta\dot{Q}_{HTL,av,ht}$ = 7.66 MW and $\Delta\dot{Q}_{HTL,av,hs}$ = 6.02 MW and heat losses, taking into account duration of seasons i.e. T_{ht} = 5616 h and T_{hs} = 2400 h, were at the level of $\Delta H_{HTL,ht}$ = 0.155 PJ and $\Delta H_{HTL,hs}$ = 0.052 PJ, for heating and summer season, respectively. Total annual losses were ΔH_{HTL} = 0.207 PJ/yr (57.5 GWh/yr), which constitutes 6% of total annual heat transported through HTL. Temperature drop was calculated at the level of: 0.031 K/km (supply pipeline) and 0.013 K/km (return pipeline) during heating season and 0.033 K/km (supply pipeline) and 0.020 K/km (return pipeline) during summer season. The results of thermal power and heat losses calculations were compared with those found in peer-reviewed papers. In [54], thermal power and heat losses were at a similar level, but in [11] heat losses were less than 2% for 150 km long heat transport line, while in [22] thermal power losses were computed at the level of 0.07-0.20 MW/km and heat losses were 1.47-1.96% of the total transported heat.

3.2 Cost of heat

The specific cost of heat from NCP was obtained using modified method related to the one presented in [28]. It was computed as total annual costs of heat supply to DHA divided by its production in a year. However, as mentioned in subsection , not only should this cost take into account the capital and fixed O&M costs of turbine adaptation ($K_{G,dh,NCP}$) and heat transport ($K_{T,dh,NCP}$), but also the cost of lost electric power ($K_{G,\Delta P,fix}$) and electrical energy ($K_{G,\Delta E,var}$), that has to be supplied by other power plant e.g. fossil-fueled. Techno-economic data of eq_FPP technology were used for calculations of these losses. Then, the cost of heat supplied to DHA was determined as follows:

$$k_{G+T,dh,NCP} = \frac{K_{G,dh,NCP}+K_{T,dh,NCP}+K_{G,\Delta P,fix}+K_{G,\Delta E,var}}{H_{NCP}} \qquad (54)$$

where fixed costs of electricity generated to compensate the loss of electrical energy resulting from district heat production in NCP were determined as:

$$K_{G,\Delta P,fix} = r_{G,eq\_FPP,CRF} \cdot k_{G,eq\_FPP,inv} \cdot \Delta P_{max,NCP} \qquad (55)$$

and variable costs of electricity needed to compensate the losses were obtained as follows:

$$K_{G,\Delta E,var} = [(k_{G,eq\_FPP,fuel} \cdot W^{-1}_{fuel,eq\_FPP} + k_{EUA} \cdot e_{G,eq\_FPP,CO_2}) \cdot \eta^{-1}_{el,eq\_FPP} + k_{G,eq\_FPP,O\&M} +$$

$$k_{G,eq\_FPP,decom}] \cdot \Delta E_{NCP} \tag{56}$$

For comparative analysis, the costs of heat from a fossil-fired cogeneration plant (FCP) were based on the assumptions of Wagner method of cost distribution in CHP plant [55] i.e. by treating the costs of electricity generation from FCP as the costs of a condensing power plant of an equal electricity production. It was formulated as follows:

$$k_{G,dh,FCP} = \frac{K_{G,el+dh,eq\_FCP} - E_{eq\_FCP} \cdot \frac{K_{G,el,eq\_FPP}}{E_{eq\_FPP}}}{H_{eq\_FCP}} \tag{57}$$

The cost of heat generation in a fossil-fueled district heating plant (FDHP) was determined as:

$$k_{G,dh,FDHP} = \frac{K_{G,dh,eq\_FDHP}}{H_{eq\_FDHP}} \tag{58}$$

4 Results and discussion

As a result of state properties computation for turbine systems of power units with all three considered types of nuclear reactors, for changing values of ambient temperature, electric power outputs (Fig. 6) and key variables of thermodynamic analysis (Table 5) were determined. Conducted research proved that if steam is extracted both from LP turbine bleeders and the HP/LP (AP1000 and ESBWR) or IP/LP (EPR) crossover pipe, nuclear power plants with considered reactor types can operate in partial cogeneration mode without the need for modifications of a primary cycle or nuclear reactor thermal capacity or both, meeting thermal load up to 250 MW. The loss of electric power at maximal considered thermal load was 3.1-5.9% of nuclear unit gross electric power output in condensing mode and the lowest percentage was for EPR, whereas power loss coefficient, primary energy savings and the amount of avoided CO_2 emission were the highest for EPR (see Table 5).

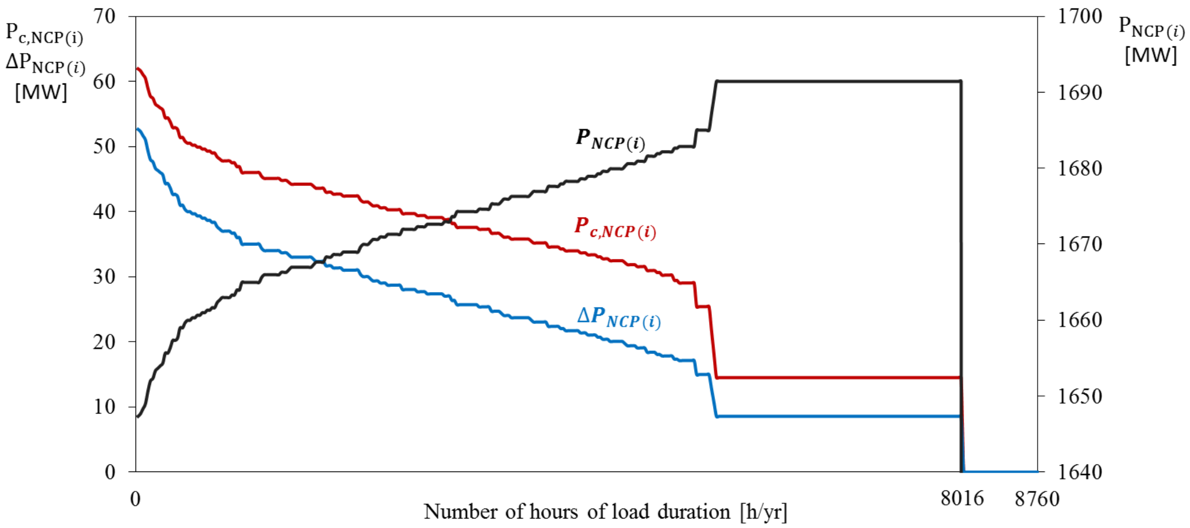

Fig. 6. Duration curves for NCP: $P_{NCP(i)}$ electric power, $P_{c,NCP(i)}$ theoretical electric power in full cogeneration, $\Delta P_{NCP(i)}$ the loss of electric power as a result of steam extraction for district heating

Table 5. Key variables values of thermodynamic analysis and energy balance of a plant for NCP

Specification		Nuclear power unit		
		EPR	AP1000	ESBWR
Water flow through NFH (heating season), kg/s, $\dot{m}_{NFH}$		917.8	917.8	917.8
Total area of NFH, m^2, $\Sigma_j A_{NFH(j)}$		2 389.7	752.1	603.9
Maximal thermal power exchanged by j^{th} NFH, MW, $\dot{Q}_{NFH(j)}$	$j = 1$	0.0	70.7	0.0
	$j = 2$	105.9	0.0	40.5
	$j = 3$	144.1	179.3	209.5
Temperature of water at j^{th} NFH inlet, °C, $t_{NFH(j)in}$	$j = 1$	65.0	65.0	65.0
	$j = 2$	65.0	83.3	65.0
	$j = 3$	92.4	83.3	75.5
Temperature of water at j^{th} NFH outlet, °C, $t_{NFH(j)out}$	$j = 1$	65.0	83.3	65.0
	$j = 2$	92.4	83.3	75.5
	$j = 3$	130.0	130.0	130.0
Terminal temperature difference for j^{th} NFH, K, $TTD_{(j)}$	$j = 1$	0.0	44.3	0.0
	$j = 2$	12.8	0.0	69.3
	$j = 3$	6.1	53.0	60.3
Loss of power as a result of heat extraction (at max. thermal load), MW, $\Delta P_{max,NCP}$		52.7	71.2	78.1
Electric power of NCP (average), MW, P_{NCP}		1 678	1 169	1 559
Electric power of NCP (at max. thermal load), MW, $P_{min,NCP}$		1 647	1 128	1 515
Theoretical electric power in full cogeneration, MW, $P_{c,NCP}$		61.9	35.9	31.6
Annual electricity production of NCP, 10^3 MWh/yr, E_{NCP}		13 447	9 372	12 495
Annual electricity loss as a result of heat extraction, 10^3 MWh/yr, ΔE_{NCP}		180	243	283
Auxiliary consumption of electricity, 10^3 MWh/yr, $E_{AUX,NCP}$		791	649	502
Electricity delivered to a common power system node, 10^3 MWh/yr, E_{CPSN}		12 643	8 807	11 746
Annual heat delivery form NCP to DHA, 10^3 MWh/yr, H_{NCP}		957	957	957

Specification	Nuclear power unit		
	EPR	AP1000	ESBWR
Overall efficiency of NPP, η_{NPP}	37.8%	35.1%	35.4%
Overall efficiency of NCP, η_{NCP}	42.2%	40.4%	39.2%
Avoided emission of CO_2, 10^6 t CO_2/yr, EM_{CO2}	9.8	6.8	9.1
Primary energy savings, *PES*	2.0%	1.8%	1.1%
Power to heat ratio, MWh/MWh, *C*	14.1	9.8	13.1
Power loss coefficient, MWh/MWh, *b*	0.188	0.254	0.296

Nuclear turbine models were validated by comparing mass flow rates of modeled turbine systems in condensing mode with those published by US NRC [26,27,31]. For EPR model, (Fig. 4) relative error computation was presented in Table 6. The values of errors in points 8, 13, 16 and 18 (Fig. 4) resulted from changing the steam generator secondary inlet and outlet mass flow rates in relation to US EPR model [27], while in points 39, 45 and 48 errors resulted from the difference in steam pressure values in condenser between both models.

Table 6. Comparison of mass flow rates between US EPR [27] and authors' EPR model

Point no.	Mass flow rate - NRC US EPR model	Mass flow rate – Authors' EPR model	Relative error [%]
3	2452.70	2450.17	0.10
8	104.32	98.71	5.38
13	153.77	157.70	2.56
16	103.17	104.51	1.30
18	116.37	124.63	7.10
20	1962.67	1964.62	0.10
24	1674.68	1689.94	0.91
25	56.59	56.87	0.49
28	88.38	88.62	0.27
31	1533.99	1544.44	0.68
32	1533.99	1544.44	0.68
33	1533.99	1544.44	0.68
39	110.59	112.91	2.10
45	75.16	65.50	12.85
48	1348.24	1366.04	1.32

The results of economic analysis were presented in Table 7. Total costs of combined electricity and heat generation and transmission of both energy carriers to common balance points: CPSN and DHA, respectively, were the lowest for NCP (option a) only for ESBWR reactor. A fossil-fuel based cogeneration plant and a power plant (option b) have proven to be the least-cost heat and power option for other reactor types i.e. AP1000 and EPR. Investment expenditures for the adaptation of a nuclear unit to operation in partial cogeneration mode and heat transport from NCP to DHA would constitute 2.0-2.5% of total investment in a nuclear cogeneration plant. The annual costs of heat production and heat transport were 2.3-3.3% of total annual costs of NCP option. The cost of heat from NCP was in the range of 37-45 EUR/MWh (10.3-12.7 EUR/GJ) - the lowest for EPR, the highest for ESBWR - and was higher than for FCP, which equaled to 22 EUR/MWh (6.1 EUR/GJ).

Table 7. Total investment expenditures, cost of heat and total annual costs of generation and transmission of electricity from the plant to CPSN and production and transport of heat from the plant to DHA – the reference case, 10^6 EUR /yr; Note: a - NCP, b - eq_FCP + add_FPP, c - eq_FPP + eq_FDHP, d - eq_NPP + eq_FDHP

	Reactor type / Heat and power system option (*tech*)											
	EPR				AP1000				ESBWR			
Parameter	a	b	c	d	a	b	c	d	a	b	c	d
Total investment cost, 10^6 EUR, $I_{G+T,tech}$	6 434	2 327	2 322	6 287	4 929	1 625	1 620	4 745	5 197	2 209	2 204	5 026
turbine modifications, $I_{tech,TM}$	3.3	-	-	-	2.1	-	-	-	1.4	-	-	-
NFH and pipelines, $I_{tech,NFH}$	2.9	-	-	-	0.9	-	-	-	0.7	-	-	-
HTL pipelines, $I_{T,ppl}$	119.2	-	-	-	119.2				119.2	-	-	-
HTL pumps, $I_{T,pump}$	0.6	-	-	-	0.7	-	-	-	0.5	-	-	-
Cost of heat, EUR/GJ, $k_{G+T,dh,tech}$	10.3	6.1	15.5	15.5	11.8	6.1	15.5	15.5	12.7	6.1	15.5	15.5
Total annual costs of generation and transmission of electricity or heat or both, 10^6 EUR/yr, $K_{G+T,el+dh,tech}$	798.1	762.1	800.7	819.8	560.9	532.9	571.5	579.3	550.1	712.8	751.4	571.0
Generation of electricity or heat or both, $K_{G,el+dh,tech}$	780.2	713.7	748.7	819.8	542.9	500.6	535.6	579.3	532.2	667.1	702.1	571.0
Capital, $K_{G,tech,cap}$	499.5	168.0	165.0	498.0	380.5	118.4	115.4	376.0	401.8	159.6	156.6	398.2
turbine modifications and NFH, $K_{NCP,TM+NFH,cap}$	0.4	-	-	-	0.2	-	-	-	0.1	-	-	-
O&M, $K_{G,tech,O\&M}$	252.6	54.0	66.8	264.3	144.3	38.4	51.2	155.8	101.6	50.4	63.1	114.6
turbine modifications and NFH, $K_{NCP,TM+NFH,O\&M}$	0.3	-	-	-	0.1	-	-	-	0.1	-	-	-
Fuel, $K_{G,tech,fuel}$	25.8	291.2	308.7	44.4	16.6	203.1	220.7	35.2	27.7	270.6	288.1	46.2
Decommissioning, $K_{G,tech,decom}$	2.3	0.9	0.9	2.3	1.5	0.6	0.6	1.5	1.2	0.9	0.8	1.2
CO_2 emission allowances, $K_{G,tech,EUA}$	0.0	199.6	207.3	10.9	0.0	140.1	147.7	10.9	0.0	185.7	193.4	10.9
Transmission of electricity from the plant to CPSN, $K_{T,el,tech}$	0.0	48.4	52.0	0.0	0.0	32.2	35.9	0.0	0.0	45.7	49.3	0.0
Transport of heat from the plant to DHA, $K_{T,dh,tech}$	17.9	0.0	0.0	0.0	17.9	0.0	0.0	0.0	17.9	0.0	0.0	0.0
heat transport line, $K_{HTL,fix}$	15.9	-	-	-	15.9	-	-	-	15.9	-	-	-
water pumping, $K_{pump,fix+var}$	0.1	-	-	-	0.1	-	-	-	0.1	-	-	-
heat losses, $K_{dh,loss}$	2.0	-	-	-	2.0	-	-	-	2.0	-	-	-

Sensitivity analysis of economic criteria, performed by changing parameters presented in Table 1, revealed that they have low effect on total costs of electricity production in NCP and its competitiveness versus coal-fueled technologies. The maximum achieved sum of total annual cost of NCP K_a was 0.3%

higher than this obtained in the reference case (Table 7.). The value of the cost of heat from NCP was more sensitive to changing parameters of heat production and transport. Maximum achieved value was 59% higher than in the reference case. Changing CO_2 emission allowance price from 20 (reference case value) to 27 EUR/t $CO_{2\text{-eq}}$ made NCP option least-cost for all reactor types.

5 Conclusions

A nuclear power plant can be a competitive combined heat and power technology even at relatively low price of CO_2 allowances, which in this case was an average value over entire time horizon of the analysis. This parameter proved to be critical for nuclear cogeneration competitiveness. Implementation of EU decarbonization policy to 2050, which can lead to multifold increase of emission allowance price [39,56], make nuclear cogeneration option an attractive alternative for fossil-fueled technologies. Turbine modifications required to convert a nuclear power plant to partial cogeneration mode are a low risk investment, since they constitute only a small fraction of total initial capital expenditures. Conversely, a project of a nuclear power plant construction is high-risk investment due to its capital intensity .

Since coal-fueled technologies are currently the least-cost options, other cogeneration systems were not taken into account (e.g. fueled with natural gas or biomass). To study the competitiveness of different technology options in long-term perspective, the energy system model, like MARKAL or TIMES, is recommended and its use is expected. These types of models require certain level of simplification in terms of technology representation, but can provide the analyst with a broader view of the optimal technology selection in district heating area. The results of the analysis of electricity and district heat sectors development in Poland [56], not including nuclear cogeneration, showed that a coal-fired combined heat and power system is the most competitive one in a long-term perspective (up to 2050), unless the scenarios of high prices of emission allowances, i.e. price paths from DECC report [39], come into effect. In such case, gas-fired and biomass-fired CHP options would be less costly.

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