

Article

Repowering a Coal Power Unit with Small Modular Reactors and Thermal Energy Storage

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Abstract: In the first months of 2022, there was a sharp turn in the energy policy of the European Union, initially spurred by increasing energy prices and further escalated by Russia's invasion of the Ukraine. Further transformation of the energy system will likely be accompanied by the gradual abandonment of natural gas from Russia and an increase of renewable and nuclear energy. Such a transition will not only increase energy security, but also accelerate the pace at which greenhouse gas emissions are reduced in Europe. This could be achieved more effectively if some of the new nuclear energy capacity is optimized to play an increased balancing role in the energy system, thus allowing for deeper market penetration of intermittent renewable energy sources with a reduced need for flexible fossil backup power and storage. A double effect of decarbonization can be achieved by investments in nuclear repowering of coal-fired units, with the replacement of coal boiler islands with nuclear reactor systems. Repowered plants, in turn, operate flexibly via integration with thermal energy storage systems using molten salt. This paper presents the results of a technoeconomic analysis for three cases of nuclear repowering of a 460 MW supercritical coal-fired unit in Poland. The first reference case assumes that three reactors are replacing the existing coal boilers, while the second reference leverages two reactors. The third uses two nuclear reactors equipped with a molten salt thermal energy storage system as a buffer for the heat produced by the reactor system. The analysis of the third case demonstrates how the TES system's capacity varies from 200 to 1200 MWh, highlighting the possibility of obtaining a high degree of flexibility of the nuclear unit due to TES system without significant drops in the efficiency of electricity production. The economic analysis demonstrates that integration with TES systems may be beneficial if the current levels of daily variation in electricity prices are maintained. For current market conditions, the most attractive investment is a case with two reactors and a TES system capacity of 800 MWh; however, with the increasing price volatility, this grows to a larger capacity of 1000 or 1200 MWh.

Keywords: supercritical steam cycles; retrofit decarbonization; small modular reactors; molten salt thermal energy storage; techno-economic assessment



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1. Introduction

The issue of European energy independence from imported fossil fuels, particularly from Russian natural gas, coal, and crude oil, has never been as critical as it is today. Previously, the long-term decarbonization strategies formulated by many of the European countries planned for the gradual departure from the use of coal and the expansion of solar and wind energy. The balancing of these types of systems over a lengthy transitional period was assumed to be provided by natural gas that was largely imported from Russia. Among the policies created at national levels, there was no common vision concerning the role that nuclear energy would play in the decarbonization processes in the future. In countries

such as Germany, Belgium, and Spain, political pressures have led to policies aimed at abandoning nuclear energy in the near term. Many other countries are pursuing nuclear new build projects or programs, including France, the United Kingdom, the Netherlands, Poland, Romania, Hungary, Slovenia, Ukraine, Finland, Czech Republic, Slovakia, and Bulgaria. In Poland, for example, measures are being taken to launch new nuclear projects that are led both by the state and by private industries in separate initiatives. The Polish State Nuclear Power Program [1] is based on three pillar of energy security, climate and environment, and economy, and it plans for the commissioning of new nuclear units with a total capacity of 6 to 9 GW by 2043.

The Russian invasion of Ukraine in February 2022 led to the need for a rapid re-examination of the decarbonization plans in many European countries. The risk of a shortage of natural gas and an increase in its price, as well as the need to limit cash flows directed toward the Russian economy, significantly undermined the transitional role that imported natural gas was projected to play in Europe. Some fraction of piped Russian gas imports may be replaced by US and Qatari liquified natural gas (LNG), but at a considerably higher cost. Plans aimed at the phasing out of nuclear energy are also being re-evaluated, with Belgium deciding to postpone the previously planned decommissioning of reactors Doel 4 and Tihange 3 by at least ten years [2]. The economies in which the construction of new nuclear power was already planned are now even more determined to act. Countries whose leading politicians remain staunchly ideologically opposed to nuclear energy, such as Germany, are instead bringing back into operation idle coal-fired power plants, even as a strong majority of their populations support the continued use of nuclear power [2].

This paper proposes and analyzes a solution that will enable the flexibility of electricity production of new nuclear energy while avoiding the stranding of existing fossil fuel assets and local job losses. This can be achieved through the repowering of existing coal power plants with small modular nuclear reactors, making use of thermal energy storage systems. Such solutions may enable nuclear reactors to be operated with a constant, nominal thermal power, with the possibility of simultaneous variability of the turbine island load in such a way that the electricity produced can balance the power system and achieve a high value factor for the electricity sold (i.e., by selling more when prices are high, and less when prices are low). Due to the existing large variation of electricity prices in daily and seasonal cycles, power units equipped with TES systems will sell electricity during periods of higher average prices and, consequently, achieve a higher income for the same volume of electricity sold.

1.1. Nuclear Reactors for Retrofits

The nuclear reactor technology most suited for the repowering of coal units is high-temperature reactors, most of which are classified as SMRs (small modular reactors). The aspect which predisposes these reactors to being promising substitutes for coal boilers is the possibility to produce steam at high parameters, at temperatures even exceeding 600 °C. High temperature also enables more affordable thermal storage. Steam generators are the elements integrating a reactor or a system of reactors with a turbine island; therefore, their parameters determine, to the greatest extent, the technical feasibility of repowering a particular coal unit. The chances for an effective retrofit increase as the steam parameters on the reactor side approach the reference parameters of the coal unit to be repowered. In addition to temperature and steam pressure, it is important to achieve as high convergence as possible in nuclear island capacity and turbine island steam demand. Due to the generally limited thermal capacity of individual modern reactor designs, mostly not exceeding 400 MW [3], the implementation of a system with multiple reactors units is most commonly considered for the decarbonization of coal units.

The group of Generation IV reactors that could potentially be the first to bring the idea of nuclear retrofits closer to reality are salt- and gas-cooled reactors. Several such reactor designs have been in operation historically, one new design entered operation (the HTR-PM in China with two reactor units) in 2021/2022, and several others are currently

in various stages of licensing. In many countries, particularly those that are not continuing investments in new coal-fired units, the date of deployment of the first reactors is crucial because of the aging infrastructure of units potentially still appropriate for repowering. A comprehensive list of worldwide constructions under development, together with information on their basic operating parameters and the expected date of their first deployments, is summarized in Reference [4]. From an engineering perspective, salt-cooled reactors are preferable solutions since their designs, unlike gas-cooled reactors, do not feature pre-integrated steam generators. It is therefore possible to design steam generators for salt-cooled reactors whose operation will match the required parameters of the steam turbine of a decarbonized coal power unit. The only limitation may be the upper bound of the molten salt temperature, which, for many of the reactors under development, is lower than the live and secondary steam temperatures used in modern supercritical coal units.

For the analyses for which results are presented in this paper, a reactor design under development by Kairos Power was used (the Kairos Power Fluoride-salt-cooled High-temperature Reactor, KP-FHR). The authors had also considered this reactor as a basis for repowering in previous analyses presented in References [3,4]. A description of the technology is presented by Blandford et al. [5]. In the KP-FHR, two closed loops transfer heat from the reactors to the steam turbine cycle via a steam generator. In a primary heat transport system, FLiBe salt (LiF/BeF_2) is used as a heat carrier. In an intermediate heat transport system, solar salt ($\text{NaNO}_3/\text{KNO}_3$) is used. The thermal power rate of a single reactor unit is 320 MW, with the temperature of solar salt at the outlet of the reactor and at the inlet of the steam generator set at 600 °C. This temperature means that the KP-FHR reactor can be considered for direct repowering of most supercritical coal-fired power units.

1.2. Molten Salt Thermal Energy Storage

The technology of storing heat in molten salt was developed in the 1990s by the Sandia National Laboratories [6]. Currently the most popular heat storage and transfer fluids are HITEC ternary salt mixture (53% KNO_3 , 7% NaNO_3 , and 40% NaNO_2) and a binary salt mixture commercially called Solar Salt (60% NaNO_3 and 40% KNO_3) [7,8]. Another popular heat transfer fluid is thermal oil [9]. Molten salt, however, appears more economically viable and generally can allow heat to be stored at higher temperatures [10,11]. Thermo-physical properties of the most popular heat transfer fluids are discussed by Giaconia et al. [12]. Currently, molten salt thermal energy storage systems are used in connection to concentrated solar power (CSP) plants. CSP systems integrated with heat storage systems are in operation in countries such as Spain, Chile, and China. Integration of CSP systems with large heat storage systems enables their operation in a regime more similar to that of coal or nuclear power units, partially decoupling power generation from the solar resource variability [13,14]. In this case, however, managing the load of the blocks must additionally depend on the current amount of stored heat and the forecasted weather. The independence of energy production from the current insolation allows the production systems to operate for a long time, at least at a minimum load, which simplifies operating procedures (especially from cold states of the turbine set) and reduces the risk associated with failures, thus reducing operating costs. Problems related to the need to frequently switch off power units more and more often also concern those sources that are powered by fossil fuels [15]. Systems of this type can also be successfully made to be flexible due to their integration with TES systems [16]. The possibility of heating the molten salt to a temperature even higher than 600 °C allows the TES systems to be directly coupled with supercritical coal-fired power units. Kosman and Rusin [17] analyzed the integration of the molten salt TES system with a turbine island which was part of a coal-fired unit, finding that such integrations would allow for greatly increased flexibility.

In the literature on the subject, thermal energy storage systems in molten salt were analyzed primarily for CSP systems. The research is often directed to the research of new mix-

tures that are capable of storing heat at higher temperatures—an important feature—while maintaining low corrosion rates. Castro-Quijada et al. [18] studied the effect of adding chlorides to solar salt. As a result of increasing the temperature range of the salt, a reduction of the required salt volume is achieved, which, in turn, allows for a reduction in capital expenditure. Boretti and Castelletto [19] investigated the effects of using the LiF-NaF-KF (FLiNaK) mixture in the TES system, which can be heated to temperatures > 600 °C. Energy storage systems can also be an element of hybrid systems where, apart from the solar source, there is an additional source of energy. Mendecka et al. [20] conducted technical and economic analyses for a system where the source of energy, in addition to solar energy, is a waste-energy stream.

The integration of nuclear systems with TES systems has been analyzed previously in a number of publications by several groups. Al Kindi et al. [21] analyzed the use of the TES system within a nuclear power unit equipped with the PWR reactor. Hovsopian et al. [22] analyzed the integration of the nuclear unit with a ternary-Pumped Thermal Electricity Storage (t-PTES) system, which consists of a heat pump, a thermal energy storage tank system, and a heat engine. The integration is carried out only on the electrical side, enabling the heat storage temperature to be independent of the temperature characteristics in the thermal cycle of the power unit. In September 2020, TerraPower and GE Hitachi Nuclear Energy (GEH) announced the launch of the Natrium concept, which features a sodium fast nuclear reactor combined with a molten salt energy storage system that will allow for over five hours of energy storage. The developers plan to apply for a construction permit in August 2023 and an operating license in March 2026 for Natrium. Kemmerer in Wyoming has been selected as the preferred site for the Natrium nuclear power plant demonstration project, where the new plant will replace the Naughton power plant, a coal plant that is due to retire in 2025. TerraPower and its utility customer PacifiCorp plan for operation of the first Natrium unit to begin in 2027.

1.3. Energy Market in Poland

Currently in Europe, including Poland, there are no mechanisms in operation that significantly encourage investors to deploy energy storage systems. An important impulse for the establishment of appropriate regulations may be the European Commission communication published on 18 May 2022, and known as REPowerEU [23]. It indicates that energy storage has a significant role to play in ensuring energy-system flexibility and its safety. The European Commission's communication mentions that energy storage will have a considerable impact on limiting the usage of natural gas in the energy system. However, it is not yet clear whether molten salt energy storage for a nuclear source would be supported by EU legislation and subsidies in the future. Therefore, for the analyses, it was assumed that only price arbitration provides a basis for the economic viability of the integration in question, with no subsidy support. Consequently, the primary objective of the analyses was to demonstrate that price volatility occurring during the daily operating cycle of nuclear systems integrated with TES systems can provide sufficient investment incentive.

In the last months of 2021, a significant increase in electricity prices could be observed in many deregulated markets. This was due to the sharply rising prices of fossil fuels, including coal and natural gas, which come to Europe in large volumes, mainly from the East. The persistently high prices of greenhouse-gas-emission allowances increased prices further; however this effect was significantly smaller. Hourly electricity prices in Poland for 2020 and 2021 are shown in Figure 1. Additionally, in this period and continuing so far into 2022, significant price fluctuations over the daily cycle were observed, and this was especially influenced by the weather conditions prevailing on the continent.

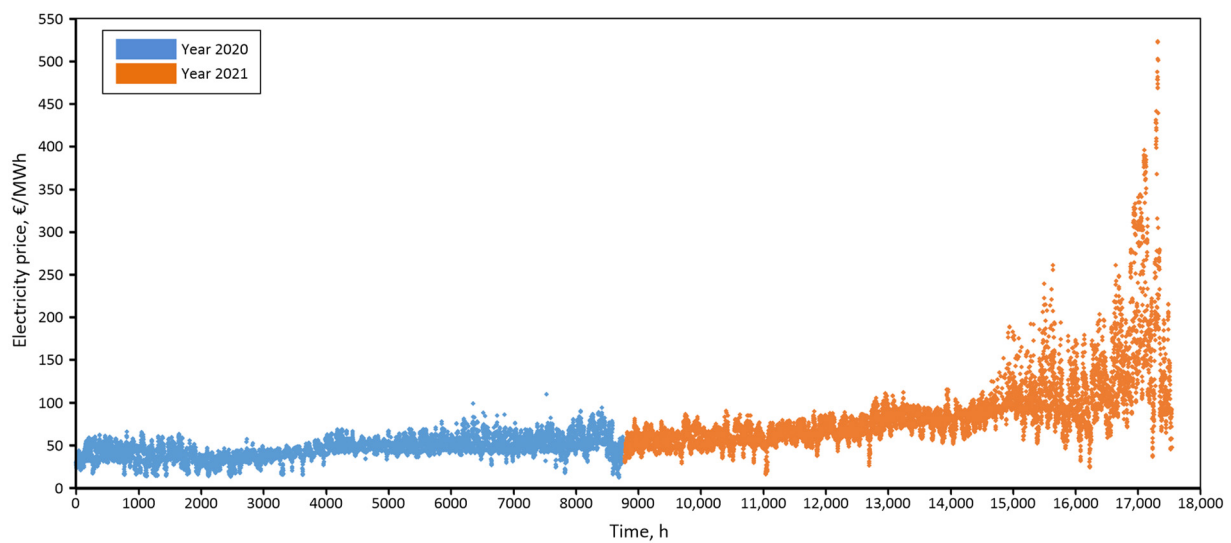


Figure 1. Average hourly electricity prices in Poland in years 2020 and 2021.

The power system in Poland is currently dominated by coal-fired units which have reached an age and technical condition that will force them to gradually shut down in the coming years. Existing and planned investments in flexible natural-gas-fired power blocks carried out in recent years look risky today in terms of gas availability and prices. High hopes are attached politically to a future potential hydrogen market, which may be a carrier for energy generated in periods of overproduction of energy from wind and solar farms, but the economics, required scale, and timing of such a system are highly uncertain [24]. In the near-term, the Polish power system can be strengthened by new cross-border connections and the construction of large-scale energy storage systems such as pumped hydro storage or compressed air energy storage, as well as the creation of favorable conditions for the development of distributed storage systems. Another option that should be considered when considering nuclear investments is the possibility of repowering existing coal units and the integration of these systems with high-temperature heat storage, which is the subject of this article.

In recent years, much has been said in Poland about the need to make the electricity generation system more flexible in the context of ensuring the country's energy security and the possibility of implementing renewable energy sources to an even greater extent. This need seems to be even more pressing in light of the situation at the eastern border of Poland.

Periods of low electricity demand, characterized by the lowest electricity prices on the market, generally occur during the night hours. Peak demand, resulting from increased economic activity and characterized by high energy prices, typically takes place during the afternoon hours. In Table 1, the average hourly prices of electricity for respective months of the years 2020 and 2021 are shown. In Table 1, for each month, eight hours characterized by the lowest average price of electricity are marked in an orange color. For each month, four hours with the highest electricity prices are also marked in yellow.

Table 1. Average monthly electricity prices for specific hours of day in Poland in years 2020 and 2021.

		Hour of Day																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
		Average Hourly Electricity Prices																							
Months in 2020	Jan	33.3	31.3	29.8	29.4	30.3	32.5	41.3	42.1	44.8	46.2	45.9	46.5	46.4	46.5	45.5	45.5	48.5	49.5	48.6	47.3	44.0	38.7	40.1	34.3
	Feb	29.4	27.0	25.6	25.4	26.2	29.1	39.6	39.6	42.6	44.0	43.7	44.0	44.5	44.9	43.6	42.5	43.9	48.0	47.6	46.6	43.1	36.3	37.3	31.7
	Mar	30.6	29.3	28.2	28.1	28.4	29.5	35.9	35.9	38.8	39.3	38.0	38.5	38.9	39.0	37.3	35.8	35.6	37.8	43.1	43.2	39.6	35.0	36.4	31.9
	Apr	30.0	28.6	27.6	26.9	27.1	27.2	31.3	33.7	36.3	36.6	35.8	36.0	35.5	35.2	33.1	32.0	31.8	31.9	33.3	37.6	40.6	35.8	35.5	30.6
	May	34.6	33.8	33.1	32.7	32.6	31.7	37.6	38.8	40.9	41.2	40.7	40.7	40.8	40.2	38.8	38.2	37.8	37.3	37.8	39.4	41.0	39.9	40.0	35.1
	Jun	41.3	40.7	40.4	40.0	39.6	39.5	45.3	46.4	51.0	52.0	51.9	52.9	53.1	51.9	49.9	47.8	46.6	45.5	45.7	46.6	46.4	45.9	47.3	43.1
	Jul	44.7	43.9	43.6	43.4	42.8	42.6	49.0	47.6	50.4	51.1	51.0	52.4	52.9	51.9	50.3	49.7	48.9	48.2	47.9	48.9	48.8	49.1	50.7	46.2
	Aug	43.0	42.2	42.0	42.1	41.9	41.5	47.4	47.5	51.9	54.2	55.0	56.7	57.5	56.9	54.2	53.3	52.0	51.2	51.0	53.3	54.1	50.0	50.8	45.1
	Sep	44.8	44.2	43.6	43.5	44.0	44.8	51.2	54.1	58.9	57.4	55.1	55.0	55.0	54.0	52.3	52.6	53.3	55.3	58.6	67.1	64.5	54.0	52.8	47.7
	Oct	43.2	42.5	41.6	41.5	42.2	43.3	51.9	51.7	56.8	57.6	56.3	57.0	56.9	56.3	54.8	55.2	56.4	57.9	61.7	63.7	56.8	48.4	49.6	44.9
	Nov	43.1	41.1	40.1	40.1	40.9	43.6	50.2	50.4	55.3	57.0	57.4	58.5	58.6	59.1	58.3	59.0	63.5	65.6	60.9	57.8	53.8	48.2	49.9	45.1
	Dec	44.3	41.2	39.5	39.0	40.1	43.5	52.2	56.5	61.1	63.5	63.4	64.5	65.1	65.1	64.3	65.1	69.3	68.4	65.2	62.8	57.5	50.7	50.4	45.4
Months in 2021	Jan	45.8	44.0	43.1	42.6	43.0	44.9	51.6	54.3	57.8	60.0	60.3	61.0	60.9	60.7	59.6	59.8	63.1	65.0	63.7	61.4	57.8	52.8	52.4	47.7
	Feb	47.6	47.0	46.2	45.9	46.7	49.8	58.1	59.9	64.0	65.5	64.1	63.2	61.9	61.4	60.4	59.6	61.2	66.3	66.8	64.6	60.8	54.7	54.8	48.7
	Mar	51.6	49.7	49.3	48.9	48.8	52.0	59.9	62.4	64.8	63.3	61.3	61.3	61.2	61.2	60.3	60.3	61.1	63.9	70.1	70.9	65.6	59.9	58.7	52.9
	Apr	55.5	52.9	51.9	51.8	52.5	54.1	62.1	64.4	66.9	63.9	60.5	59.7	58.1	56.8	54.8	54.6	55.7	57.4	62.9	68.6	70.8	65.6	64.4	58.1
	May	61.8	59.2	58.1	57.7	57.6	58.0	66.3	69.6	71.7	68.2	64.2	63.6	61.8	60.3	58.7	59.3	60.3	63.2	67.9	73.7	76.6	73.6	70.8	64.9
	Jun	70.4	66.3	64.2	63.2	62.5	64.5	72.8	77.3	80.4	78.9	75.6	75.0	73.8	72.2	70.9	71.4	72.5	76.1	82.4	88.3	89.0	85.7	81.5	75.4
	Jul	77.9	74.4	72.2	71.5	70.7	72.7	79.0	81.5	84.7	84.9	83.7	83.5	83.0	81.7	80.3	80.9	82.0	84.2	87.3	90.8	91.6	89.7	86.6	82.2
	Aug	76.4	73.0	71.4	70.5	70.5	72.5	79.8	82.2	85.9	85.6	83.0	82.8	81.9	79.7	77.7	78.1	79.7	84.0	88.9	93.2	95.6	90.7	87.5	80.8
	Sep	92.1	89.8	88.6	88.2	88.5	91.5	95.7	98.9	105.5	104.7	99.8	99.8	97.5	94.5	92.8	95.0	99.6	105.9	115.2	141.0	139.4	103.1	98.9	92.8
	Oct	81.3	78.1	76.6	76.9	78.8	85.9	102.2	110.8	123.3	121.2	110.7	105.6	100.2	96.9	96.5	103.5	113.3	129.5	151.2	155.3	130.1	96.0	93.0	84.4
	Nov	87.7	82.7	80.2	79.9	82.9	88.3	108.4	110.5	126.5	131.1	126.5	129.5	130.1	134.2	135.5	144.6	163.6	166.0	157.3	147.7	126.9	104.6	105.6	93.2
	Dec	123.9	116.1	111.8	110.6	114.3	124.8	153.7	152.1	200.1	217.2	218.2	225.3	226.1	232.2	224.6	230.9	245.8	240.0	226.6	213.1	179.6	136.9	148.2	126.8

Yellow—indication of four hours for each month of 2020 and 2021 in which average electricity prices are the highest; orange—indication of eight hours for each month of 2020 and 2021 in which average electricity prices are the lowest.

As part of the economic analyses, the deviations of peak and valley prices from average prices were used. For the annual period, an average price of electricity can be determined. For this purpose, Equation (1) can be used:

$$C_{el_av} = \frac{\tau_v C_{el_v} + \tau_p C_{el_p} + \tau_o C_{el_o}}{\tau_v + \tau_p + \tau_o} \quad (1)$$

where C_{el_v} is average electricity price at the valley period, C_{el_p} is average electricity price at peak-production period, C_{el_o} is the average electricity price at other periods, τ_v is duration of the valley-production period (2572 h for 2021: 8 h/day for 2021), τ_p is duration of the peak-production period (1376 h for 2021: 4 h/day for 2021), and τ_o is duration of the other period (4308 h for 2021: 12 h/day). Moreover, $\tau_v + \tau_p + \tau_o = 8256$ h; it was assumed that renovation period is three weeks: from 18 July 2021, 10 p.m., to 8 August 2021, 10 p.m.).

The deviation of the average price in the electricity peak demand period from the average price is determined as follows:

$$\Delta c_{el_v} = \frac{C_{el_v} - C_{el_av}}{C_{el_av}}, \quad (2)$$

$$\Delta c_{el_p} = \frac{C_{el_p} - C_{el_av}}{C_{el_av}}. \quad (3)$$

For 2020, the average price, as calculated by Equation (1), was 45.28 EUR/MWh. In 2021, this price was almost twice as high and amounted to 86.48 EUR/MWh. Prices have continued to be very high and volatile during 2022 so far. The average annual price in the electricity peak demand period in 2020 and 2021 was, respectively, 52.33 and 106.11 EUR/MWh. The average annual prices in the electricity “valley period” for 2020 and 2021 were 38.14 and 71.24 EUR/MWh, respectively.

In general, a greater differentiation of prices occurring in energy valleys and prices occurring in periods of peak demand takes place in the winter months. The highest differentiation was observed for the last months of 2021, when energy prices were at a record high.

Deviations of the average annual prices in the year 2020 and 2021 were as follows, respectively:

$$\Delta c_{el_v(2020)} = -0.1576,$$

$$\Delta c_{el_p(2020)} = 0.1557,$$

$$\Delta c_{el_v(2021)} = -0.1763,$$

$$\Delta c_{el_p(2021)} = 0.2270.$$

The illustrated price differentiation, increasing year by year in European markets due to the progressive increase in the potential of intermittent renewable energy sources, is a very important factor that may promote interest in molten salt thermal energy storage. Such integrations, with a sufficiently high price differentiation in the periods of energy valleys and peak-demand periods, may be beneficial not only from the point of view of the country’s energy security, but also from the economic point of view.

2. Methods

The analyses for which the results are shown in this paper were focused on both the technical and economic effects of the integration of nuclear units in repowering an existing coal plant and the addition of a molten salt thermal energy storage system. The basis for the analysis was the concept of a power unit being retrofitted to an existing supercritical coal-fired power unit. The retrofit assumes the replacement of the boiler island with a system of nuclear reactors, ensuring the production of heat for the needs of steam generation in the steam generator, which is an element of the steam turbine cycle. The

results of technical and economic analysis for such a retrofit, which were carried out earlier by the authors, are presented in Reference [4]. However, the previous analysis did not include the option of integrating the block with a molten salt thermal energy storage system. Additionally, the previous analysis was carried out with the assumption that the unit is not operating for the purposes of producing heat for the district heating system, and its electric power output was assumed to be constant. The results of the analysis carried out for the purposes of this article concern a power unit operating for the needs of a district heating network, for which the current demand for heat is determined by the ambient temperature. This state of affairs reflects the current situation for the reference unit operating at the Łagisza power plant located in Poland. The block started producing heat for the municipal heating network after a modernization of the plant took place in 2020. The techno-economic analyses were carried out for three cases of the structure of a nuclear unit, two of which assume the operation of the system without its integration with the TES system, while one case involves connecting two tanks for molten salt, constituting the heat storage system, between the nuclear island and the turbine island. The cases without TES systems were the reference cases in the analysis.

Section 2.1 presents the characteristics of the coal-fired unit, in particular the description of the turbine island. Section 2.2 describes the different variants of the analyzed systems. This section also presents the basic assumptions for the study. The model used to simulate the operation of the systems is described in Section 2.3. The results of the model validation are also presented there.

2.1. Coal-Fired Reference Unit

The reference coal-fired unit has an electric capacity of 460 MW and is equipped with a fluidized bed boiler. The unit was commissioned in 2009 and is currently the smallest supercritical unit operating in Poland (there are 8 supercritical units with a total capacity of 6083 MW in total) [4]. The selected unit was the first unit in the world that was equipped with a fluidized bed boiler with supercritical parameters. The unit operates within the Łagisza power plant, owned by the Tauron Polska Energia SA Group, which is the second largest producer of electricity in Poland. The power plant is located in Będzin, in the Śląskie Voivodeship. Since the start of operation in 2009, the unit has been modernized to increase reliability and efficiency and reduce emissions. One of the most important modernizations was the modernization completed in 2020, which made it possible for the unit to supply heat to a local district heating network. This allowed the utility Tauron to finally retire two worn-out 120 MW coal-fired units equipped with extraction-condensing turbines. The current simplified diagram of power unit is shown in Figure 2.

The change of load of the CHP plant is the result of the need to adapt the characteristics of the operation to the following characteristics of the district heating network. Analyses for all variants were performed for a reference year with an assumed ambient temperature profile appropriate for the location where the 460 MW unit is located. The low-to-high-ordered and chronological ambient temperature, which determines the heat demand for heating purposes, is shown in Figure 3. It was assumed that the CHP unit works for a heating network that is characterized by a maximum heat demand of 180 MW. The maximum heat power of the CHP unit is limited by the minimum steam flow through the low-pressure turbine, which is assumed to be 90 kg/s. This assumption was made after the analysis of the thermal measurement report provided by Tauron [25]. The CHP unit produces heat for heating purposes if the ambient temperature is below 12 °C. Regardless of the ambient temperature, the unit produces heat for the preheating of useful hot water. It is assumed that the heat demand for water heating is 18 MW. The ordered (high-to-low) and chronological heat demand characteristics are shown on the right side of Figure 3.

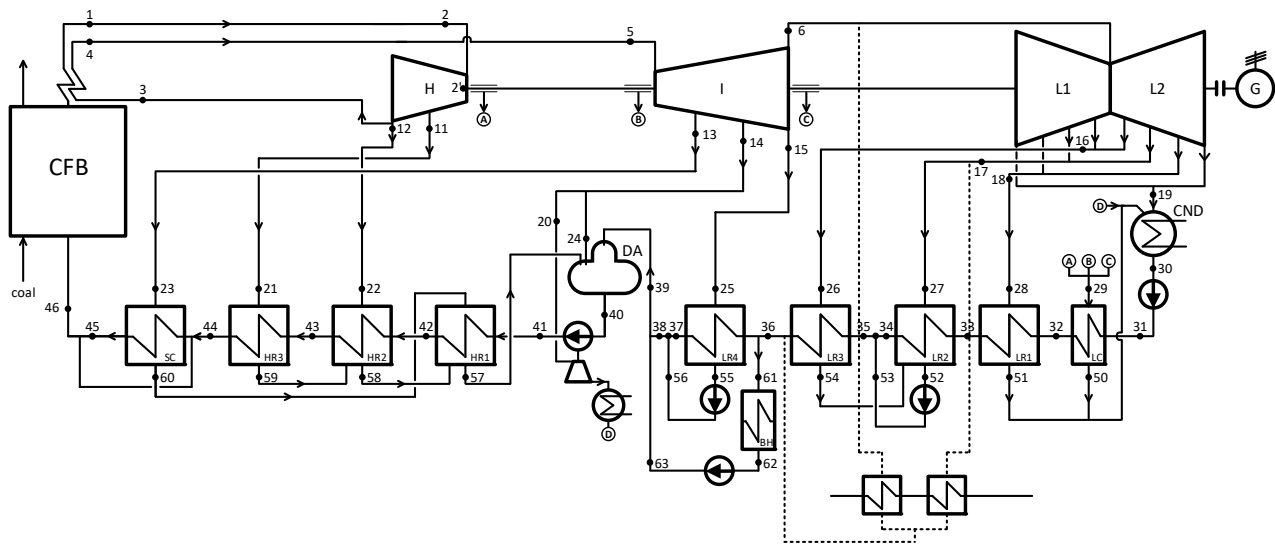


Figure 2. Simplified diagram of the Łagisza 460 MW unit.

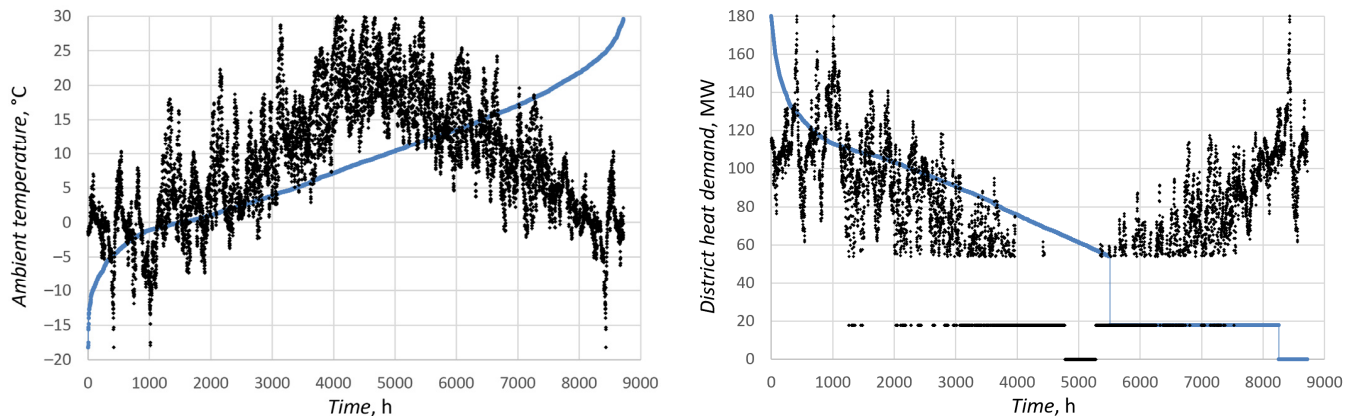


Figure 3. Ordered (blue color) and real (black color) diagrams of ambient temperature (**left side**) and ordered (blue) and real (black) diagram of heat demand for the district heating system (**right side**).

2.2. Nuclear Repowering Options

Analyses were performed for three cases of the power unit being the result of nuclear repowering. Two of these cases are reference options, which do not include TES systems. The purpose of carrying out the analyses for the reference cases was to obtain results that would serve as a benchmark for evaluating the system according to the third case, i.e., the case that assumes the use of molten salt TES within the nuclear unit. In each reference case, the only element of heat transfer between the salt, which transfers heat out of the nuclear reactor system, and the water, which is the working medium of the steam turbine unit, is the steam generator that is equipped with heat exchangers which preheat and superheat the supercritical medium in the same way as was achieved in the coal-fired boiler.

The first reference case (REF_3NR) assumes the use of a system of three KP-FHR reactors, each with a thermal capacity of 320 MW, whose total thermal power (960 MW) very closely approaches the nominal thermal power of the removed steam boiler (957.1 MW). Such a close matching of values allows, firstly, the nuclear unit to produce the highest possible power output because the steam turbine unit is operating at its maximum potential. On the other hand, maintaining a constant load on the nuclear reactor system implies an economic desirability to run the turbine island at a constant high load, making the system inflexible, as was the case with the coal-fired unit before its retrofitting. Of course, this reference case is also the option with the highest investment costs due to the need to purchase and build three nuclear reactors. A scheme of the system according to the

REF_3NR case is shown in Figure 4. The structure of nuclear island for this case was the same as the structure that was analyzed in Reference [4].

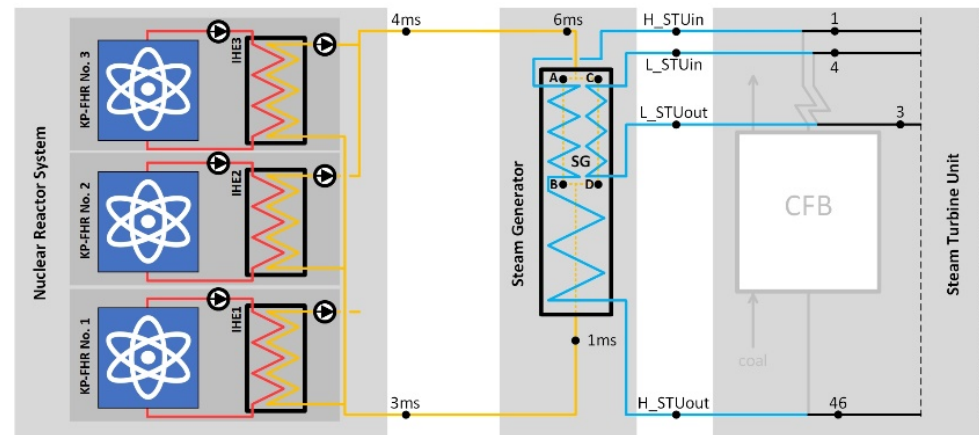


Figure 4. Integration diagram of 3 nuclear reactors with the steam turbine unit (Case REF_3NR).

The second reference case (REF_2NR) is a solution with the same organization of the integration of the nuclear reactor system with the turbine island as in the REF_3NR case, but with the number of nuclear reactors reduced to two. The reduction of the thermal capacity directed to the turbine island means that the turbine operates with limited power capacity. The scheme of the system according to case REF_2NR is shown in Figure 5.

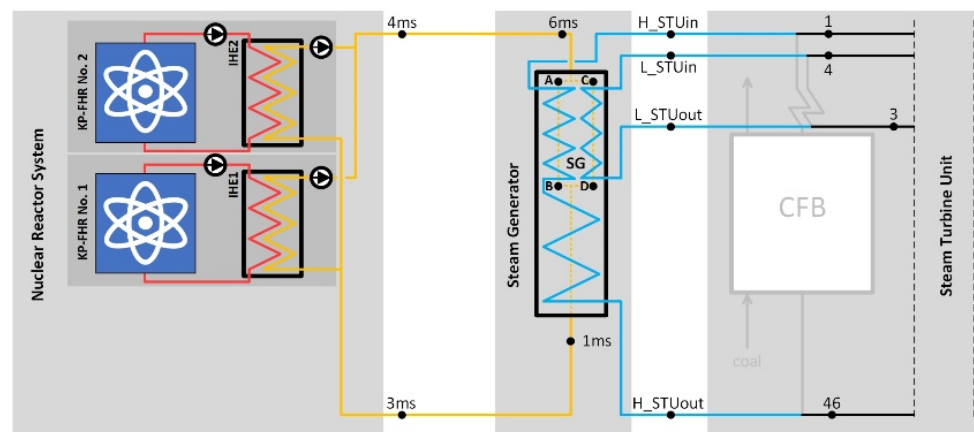


Figure 5. Integration diagram of 2 nuclear reactors with the steam turbine unit (Case REF_2NR).

The third case (TES_2NR) is the case that assumes the retrofit of the nuclear unit with a TES system. In this case, the nuclear system, as in the REF_2NR case, consists of two parallel-operating nuclear reactors, each with thermal power of 320 MW. However, the difference is that, in the TES_2NR case, the TES system is involved in transferring part of the heat between the nuclear island and the turbine island where the heat is periodically buffered. This type of buffering enables the steam turbine unit to vary its load in response to the constant output of the nuclear reactor system, giving the nuclear power plant the desirable flexibility to match its output profile to current electricity demand. For the purpose of analysis, it was assumed that the TES system consists of two tanks, one of which is a low-temperature tank where salt with a temperature of 300 °C is stored. Salt at this temperature in the period of peak demand is injected into the tank after leaving the steam generator, where the molten salt transfers heat to the working medium of the steam turbine unit. The second reservoir is a high-temperature tank, where molten salt leaving the nuclear reactor system at 600 °C is stored. Molten salt is injected into the high-temperature tank in situations of overproduction of heat in the nuclear reactor system occurring in

relation to the current heat demand of the turbine island. It was assumed that such an overproduction of heat occurs during the energy valley when the price of electricity reaches the lowest values. For the purpose of the analyses, it was assumed that the duration of the energy valley each day is identical and equal to 8 h and that the heat flux buffering during this time in the TES system is constant (if it is possible from technical limitations of steam turbine unit point of view) and is the primary decision variable for the analyses. The analyses were performed for heat fluxes directed to the TES system at 25, 50, 75, 100, 125, and 150 MW. It was assumed that the thermal energy after the charging stage of the TES system is stored in the system until the start of the peak demand period, when the market experiences high prices. The peak energy demand period was assumed to last 4 h. During this period, the hot molten salt stored in the high-temperature tank flows to the steam generator and then, after cooling, is injected into the low-temperature tank. It was assumed that the efficiency of heat storage in the TES system is 95%, which means that 5% of the amount of heat introduced into the TES system is dissipated to the environment, so that it is not directed to the steam turbine unit. The scheme for the system according to the TES_2NR variant is shown in Figure 6.

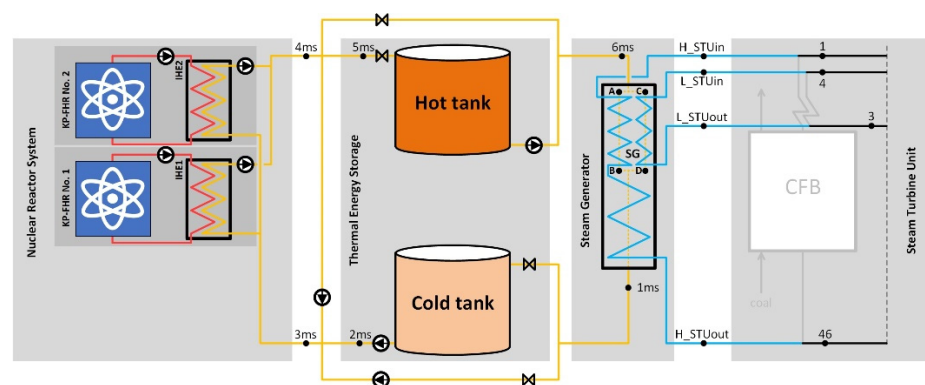


Figure 6. Integration diagram of 2 nuclear reactors and TES system with the steam turbine unit (Case TES_2NR).

2.3. Modeling and Design

The model of the power unit is based on the use of mass and energy balance equations for individual components of the steam–water cycle and the steam expansion line computational algorithm in subsequent stages of the steam turbine. The thermal diagram for the 460 MW unit, which was the basis for the development of the calculation model, is shown in Figure 2. The low-pressure turbine has four extraction ports for low-pressure feedwater heating. Preheat condensate takes place in the leaks cooler (LC). The low-pressure regenerative feedwater heaters (FWH) LR1, LR2, and LR3 are supplied with steam taken from the extraction ports of the LP section of the steam turbine. The LR4 FWH is supplied with steam taken from a bleed port located between the IP section (I) and LP sections (L1 and L2) of the steam turbine. After the heat transfer in the diaphragm heat exchangers, the condensate is directed to the deaerator, which is fed with steam taken from the extraction ports of the IP steam turbine. The HP regeneration consists of three regenerative heat exchangers and a steam cooler (SC). The HR3 FWH is supplied with steam taken from the extraction port of the HP section of the steam turbine. The HR2 FWH is supplied with steam taken from a bleed port located between an HP section and reheater. The HR1 FWH is supplied with steam taken from an extraction port of the IP section steam turbine, after its initial cooling in the steam cooler. The feedwater train includes feedwater and condensate pumps.

A previous analysis that was carried out for the 460 MW unit, for which the results are presented in Reference [4], differed from the analysis in this study. The reference unit selected for the previous analysis was for an electricity-only plant, not a combined heat and power unit, and therefore corresponded to the system present at Łagisza before 2020. The main difference in terms of computational requirements was the need to conduct an

analysis of the turbine island with its variable load. Such a variable load resulted in the need to vary the level of demand for heat sent to consumers. The need to simulate the steam turbine assembly also resulted from the variable value of the thermal power transferred to the steam turbine assembly from the TES system, which is an element that makes the nuclear system more flexible. The need to simulate the reaction of the steam turbine assembly to the change of these heat fluxes on the control casing of the turbine assembly required, especially for this purpose, the development of a new computational model.

The main purpose of using the model was determining the gross electrical power of the steam turbine unit for the two assumed thermal energy fluxes. The new model was developed in Engineering Equation Solver software [26] and makes use of the IAPWS-IF97 steam tables. The key task in building the steam turbine cycle model is to represent the actual steam expansion line in the steam turbine. For this purpose, it was necessary to determine internal efficiency for each group of blade stages. Models of STUs made it possible to determine changes in the value of internal efficiency for individual groups of blade stages, which are the result of changes in their load. The generalized equation for the determination of the isentropic efficiency of the turbine stages' group of respective parts of the steam turbine after load change is defined as follows:

$$\frac{\eta_{iST}}{(\eta_{iST})_n} = A \left(\frac{\dot{m}}{(\dot{m})_n} \right)^2 + B \frac{\dot{m}}{(\dot{m})_n} + C, \quad (4)$$

where for the high-pressure part, $A = 0.0210$, $B = -0.0500$, and $C = 1.5314$; for the intermediate-pressure part, $A = 0.0502$, $B = -0.1222$, and $C = 1.0720$; and for low-pressure part, $A = 0.0390$, $B = -0.1210$, and $C = 1.0290$.

In addition, the capacity flow equation for the steam turbine was used to correlate the steam mass flow flowing through individual steam turbine sections with the pressure distribution at the inlet and outlet of the given section. Flügel–Stodola's law for flow capacity of turbine stages group is described by the following equation:

$$\frac{\dot{m}}{(\dot{m})_n} = \sqrt{\frac{(T_{in})_n}{T_{in}}} \sqrt{\frac{p_{in}^2 - p_{out}^2}{(p_{in})_n^2 - (p_{out})_n^2}}, \quad (5)$$

where T_{in} is the steam temperature at inlet of stage group, p_{in} is the steam pressure at inlet of stage group, p_{out} is the steam pressure at the outlet of stage group, and n is the nominal load.

The model includes certain simplifications. It was assumed that the change in heat exchanger load does not change in terms of heat exchange conditions—the value of the heat transfer coefficient is fixed regardless of changes in mass flows and temperature distribution. An additional simplification was the assumption of no effect of changes in flow conditions on specific nominal values of pressure loss coefficients. It was considered that, for the simulated ranges of load variability, these simplifications are acceptable and do not lead to significant calculation errors. Possible works to demonstrate in more detail the effects of integration would require the use of dedicated commercial tools and further study.

The validation of the model was based on the data provided by Tauron [25]. The data are the results of operational measurements carried out in March 2020, after the modernization of the heating the unit. Measurements were carried out for variable load levels of the steam boiler and district heating heat exchangers. In total, there were measurements carried out for 14 load cases. The results of these measurements became the basis for the validation of the steam turbine model. The simulations with the use of the model were aimed at matching the value of thermal power of district heating heat exchangers, the temperature of live steam, and the heat flux used for the production of live steam in the

boiler. The validation of the developed model was carried out by using the model error index constituting the relative difference, which is defined as follows:

$$\Delta w = \frac{w_m - w_{tmr}}{w_{tmr}} \cdot 100\%, \quad (6)$$

where w_m is value of the physical quantity constituting the result of the model operation, and w_{tmr} is value of the physical quantity taken from the thermal measurement report.

The results of the error analysis are summarized in Appendix A, Table A1. The results of the validation show that the model closely matches measured value. The relative errors in relevant parameters usually do not exceed 1%. The greatest discrepancies occur in the case of the feed water stream. This is due to the highly complicated leakage management within the power unit, as well as difficulties in modeling the injection water stream used to regulate the temperature of the live steam.

2.4. Economic Assessment

2.4.1. Assessment Indicators

The economic analyses were based on the same methodology as the previous analyses of nuclear retrofits, for which the results were presented in Reference [4]. It was assumed that the power units equipped with SMRs operate in a regulated electricity market, with loan guarantees and with regulated prices, similar to the currently operating coal-fired units in Poland.

For all nuclear retrofits, analyses were performed by using an index such as Net Present Value (NPV). In general, the NPV can be calculated as follows:

$$NPV = \sum_{\tau=1}^n \frac{NCF_{\tau}}{(1+r)^{\tau}} - TCIC, \quad (7)$$

where n is the plant lifetime, NCF_{τ} is the nominal cash flow in year τ , r is discount rate, and $TCIC$ is the total capital investment cost over the construction time (including the financial costs).

The nominal cash flow can be calculated as follows:

$$NCF_{\tau} = OMC_{\tau} + DEC_{\tau}, \quad (8)$$

where OMC_{τ} represents the operations and maintenance costs in year τ , and DEC_{τ} represents the decommissioning costs in year τ .

The OMC_{τ} was calculated by using the following equation:

$$OMC_{\tau} = FOMC_{\tau} + VOMC_{\tau}, \quad (9)$$

where $FOMC_{\tau}$ is the fixed part of costs, and $VOMC_{\tau}$ is the variable part. The following equations were used to determine the cost parts:

$$FOMC_{\tau} = [uFOMC(NI) + uFOMC(TI)] \left(N_{el,g} \right)_{nom}, \quad (10)$$

$$VOMC_{\tau} = \left\{ [uVOMC(RC) + uVOMC(SFC)] \frac{l_{NR}}{3} \left(N_{el,g} \right)_{nom} CF \cdot 8760 + uVOMC(nmTI) \cdot E_{el,g} \right\}_{\tau} \quad (11)$$

where $uFOMC(NI)$ is the unit fixed O&M costs for nuclear island, $uFOMC(TI)$ is the unit fixed O&M costs for turbine island, $uVOMC(RC)$ is the unit refueling costs, $uVOMC(SFC)$ is the unit spent nuclear fuel costs, $uVOMC(nmTI)$ is the unit non-fuel and non-emission costs for turbine island, $\left(N_{el,g} \right)_{nom}$ is the nominal gross power of a nuclear power unit that uses three nuclear reactors, and l_{NR} is number of nuclear reactors in system.

The total capital investment cost for nuclear retrofit was calculated by using the methodology which is described in Reference [4]. The methodology is based on the use

of a retrofit savings factor which indicates the potential savings that can be achieved with a nuclear retrofit investment in relation to a greenfield investment that may result from the use of the existing infrastructure in the retrofit coal-fired unit. Estimating the amount of total capital investment cost for the power units by using the TES system requires an additional estimation of the part of the cost associated with the installation of the TES components and interests during construction. The total investment cost was calculated as follows:

$$TCIC = OCC_{GF}(1 - RS) + OCC_{TES} + IDC, \quad (12)$$

where OCC_{GF} is overnight capital cost for greenfield nuclear investment, RS is retrofit savings, and IDC is the interests during construction.

The IDC was calculated based on Reference [27]:

$$IDC = \frac{N}{2} \left[\frac{OCC_{GF}(1 - RS) + OCC_{TES}}{N} (1 + r_l)^{N-1} - \frac{OCC_{GF}(1 - RS) - OCC_{TES}}{N} \right], \quad (13)$$

where OCC_{GF} is overnight capital cost for greenfield nuclear investment, OCC_{TES} is overnight capital cost for TES system, and r_l is the interest rate on the construction loan.

Using the NPV as a basis for comparison between systems with widely differing investment levels (especially between systems with different numbers of nuclear reactors) is always difficult. For this reason, we decided to use the Net Present Value Ratio ($NPVR$) as an additional index to evaluate the case studies. This index is defined by the following relations:

$$NPVR = \frac{NPV}{TCIC}. \quad (14)$$

To evaluate the economic viability of equipping a nuclear unit with TES, ΔNPV was used and calculated as follows:

$$\Delta NPV = \sum_{\tau=1}^n \frac{(NCF_{TES_2NR,\tau} - NCF_{REF_2NR,\tau})}{(1 + r)^\tau} - TCIC_{TES_2NR}. \quad (15)$$

In addition, the discounted payback period (DPP) was calculated for all cases:

$$NPV = 0 = \sum_{\tau=1}^{DPP} \frac{NCF_\tau}{(1 + r)^\tau} - TCIC. \quad (16)$$

The discounted payback period for the separated investment in TES (DPP^*) was also determined. In this case, the following formula was used:

$$\Delta NPV = 0 = \sum_{\tau=1}^{DPP^*} \frac{(NCF_{TES_2NR,\tau} - NCF_{REF_2NR,\tau})}{(1 + r)^\tau} - TCIC_{TES_2NR}. \quad (17)$$

2.4.2. Assumptions

Performing economic analyses by using the presented methodology required several assumptions that are supported by the discussion in Reference [4]. In that work, the authors referred to the issues of investment costs, operating and maintenance costs, and assumptions regarding construction times and operating times of units that may be the result of nuclear retrofits carried out.

All of the assumptions correspond to values predicted for 2031, which is considered the first year of operation of the unit after the potential investment process is completed. The assumptions are the same for all analyzed cases. The decision variables in the analyses were the relative deviation of electricity prices occurring in the energy valley and during the peak demand period relative to the average price. These indexes are defined by relations (2) and (3). The deviation in the valley period of course always takes on negative values, while in the peak demand period only positive values. In the performed analyses it was assumed that the modules of the assumed values are always the same. The nominal values for the

relative deviations were taken as -0.2 and 0.2 , respectively. The analyses were conducted for a range of values from 0 to ± 1 .

Assumptions for the analyses, along with relevant references, are summarized in Table 2.

Table 2. Base economic parameter assumptions.

Parameter	Symbol	Value	References
Lifetime			
Construction time, years	CT	4	[28]
Time of operation in year, %	τ_a	8256	[25,29]
Total operation time assumed for the NPV analysis, years	TOT	50	[30]
Capital costs			
Unit overnight capital cost (GF investment type, w/o TES system), EUR/kW	$uOCC_{GF}$	3500	[28]
Unit overnight capital cost for TES system, EUR/kWht	$uOCC_{TES}$	50	[20]
Retrofit savings, %	RS	32	[3]
Interest rates on construction loan, %	r_l	5	[28]
Variable O&M costs			
Refueling costs, EUR/MWh	$uVOMC(RC)$	7	[31,32]
Spent nuclear fuel costs, EUR/MWh	$uVOMC(SFC)$	5	[33,34]
Electricity average price, EUR/MWh		85	*
Relative difference between the peak-production electricity price and the average price	ΔC_{el_p}	0.2	*
Relative difference between the valley-production electricity price and the average price	ΔC_{el_v}	-0.2	*
Heat price, EUR/MWht	C_q	36	*
Non-fuel and non-emission costs for turbine island, EUR/MWh	$uVOMC(nnTI)$	1.50	*
Fixed O&M costs, EUR/MW/y			
Turbine island, EUR/MW/y	$uFOMC$	104,000	[28] *
Nuclear Island, EUR/MW/y	$uFOMC(TI)$	20,000	*
	$uFOMC(NI)$	84,000	[28]
Others			
Discount rate, %	r	6	*
Annual inflation rate, %		2	
Tax rate, %		19	

* Based on experience and recommendations of authors.

3. Results

3.1. Technical and Energy Performance Assessment Results

The fundamental results obtained by using the thermodynamic model were the operating characteristics of a steam turbine unit. The models made it possible to obtain the characteristics for many parameters, which are important in the aspect of technical evaluation of systems, as well as in the aspect of economic efficiency evaluation. The characteristics for the basic thermodynamic parameters characterizing the state of the working medium of the turbine unit were obtained, and this allowed us to determine the power of the steam turbine and became the basis for determining the amount of electricity produced by the system on an annual cycle. Example characteristics were shown as a function of time for the first week of the reference year. Figures 7 and 8 show the pressure and live steam mass flow characteristics, respectively, for different systems, including reference systems and units integrated with TES systems with two extreme thermal capacities, i.e., 200 and 1200 MWh. Figure 9 shows the charge state of the TES system for these extreme cases. The characteristics illustrate the performance of the TES system under varying operating conditions, where, in a diurnal cycle, the system is first charged during the night valley period and then stores heat to be finally discharged during the peak electricity demand period. Figure 10, on the other hand, shows the effects of changes in the power of the steam turbine unit resulting from the operation of the TES system. In Figure 10, the characteristics

specific to the variants of nuclear units integrated with TES systems are compared with those obtained for the two reference variants.

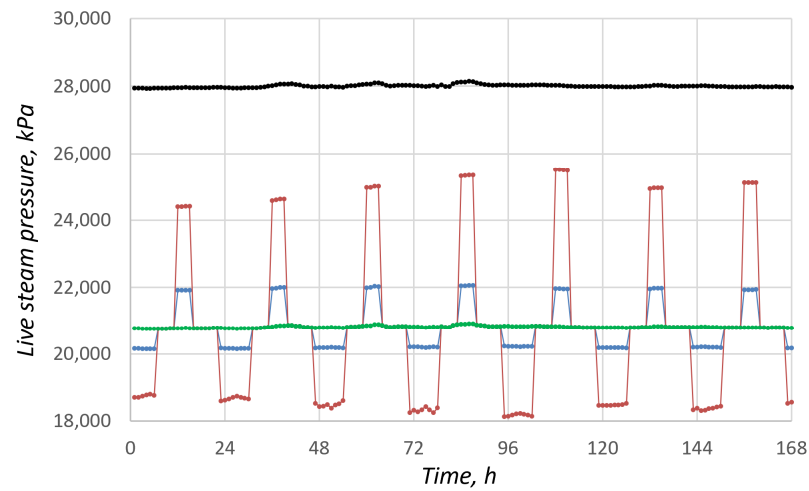


Figure 7. Live steam pressure as a function of time for first week of reference year (black—REF_3NR, green—REF_2NR, blue—TES25 (200 MWh), and red—TES150 (1200 MWh)).

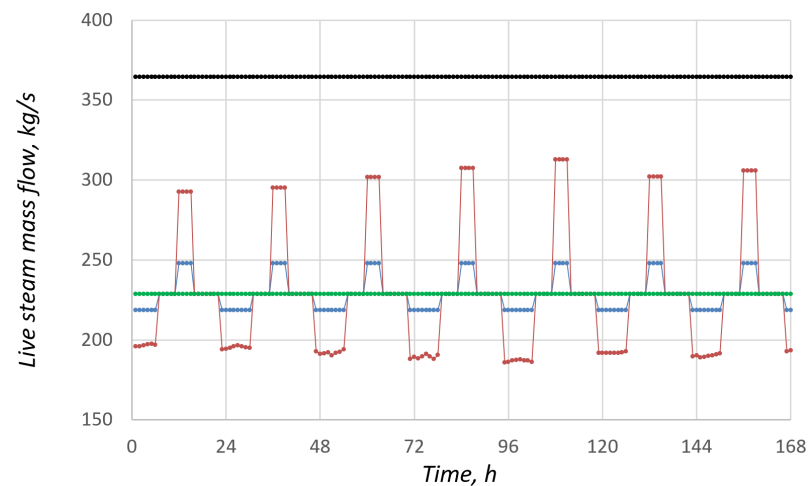


Figure 8. Live steam mass flow as a function of time for first week of reference year (black—REF_3NR, green—REF_2NR, blue—TES25 (200 MWh), and red—TES150 (1200 MWh)).

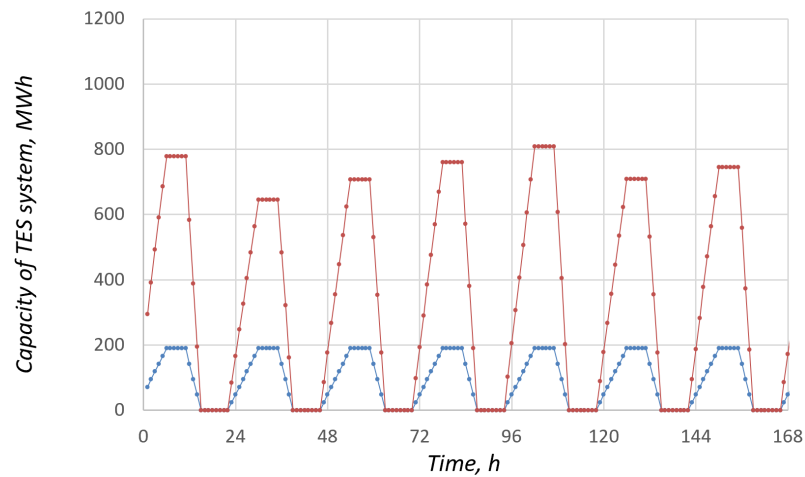


Figure 9. Capacity of TES system as a function of time for first week of reference year (blue—TES25 (200 MWh), and red—TES150 (1200 MWh)).

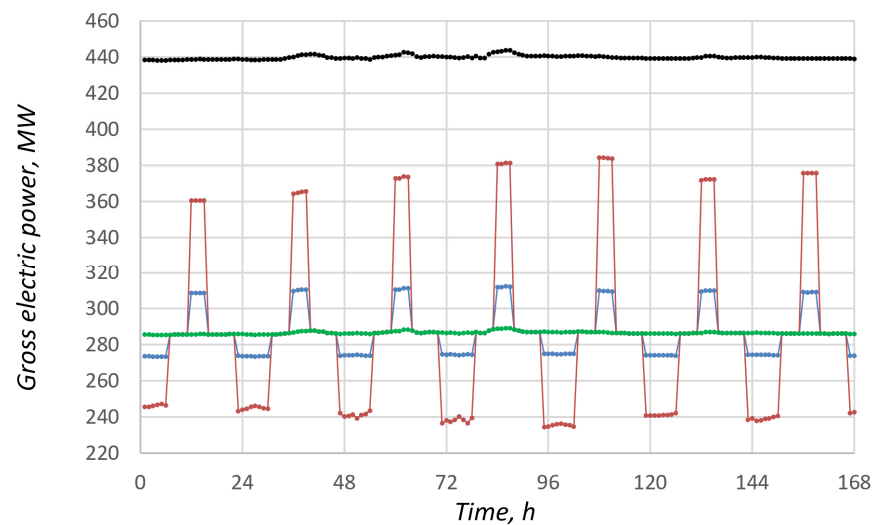


Figure 10. Gross electric power as a function of time for first week of reference year (black—REF_3NR, green—REF_2NR, blue—TES25 (200 MWh), and red—TES150 (1200 MWh)).

Figure 11 summarizes the characteristics of the TES charge state as a function of time for all cases of systems where molten salt heat storage is implemented. This time the characteristics are shown for a full reference year. For each variant, the maximum capacity to which the systems can be charged is marked. As can be observed, the TES system with the lowest volume is the system where the available storage capacity is fully utilized regardless of the block operating conditions. As the TES volume increases, the utilization rate decreases. If the available capacities are not fully utilized, this is mainly during the winter period. This is due to the fact that the heat available in the system is used not only for electricity production but also for district heat production. Figure 12 summarizes, in a similar way, the gross power characteristics of the nuclear units. In this case, the characteristics are also for the reference cases. The figure illustrates, in a useful way, the effect of the integration of the nuclear system with the TES system. While in the case of the reference systems, the slight fluctuation in the power generated by the steam turbine unit is due to the intake of a variable amount of steam supplying the heat exchangers (according to the heat demand characteristics shown in Figure 3), in the case of nuclear units equipped with TES systems, the amount of power returned to the power system on a daily basis can be significantly controlled. While the power generated by a reference system equipped with two nuclear reactors varies over the year in a small range, from 283.4 to 296.3 MW (which is in the range of the relative electrical load of the steam turbine unit from 61.6% to 64.4%), a unit equipped with even the smallest TES system under consideration can vary in electrical power from 271.5 to 319.8 MW (which is in the range of the relative electrical load of the steam turbine unit from 59.0% to 69.5%). Equipping the unit with a TES system of the largest volume under consideration results in the possibility to change the electric power from 217.1 to 436.9 MW (which is within the range of the relative electric load of the steam turbine unit from 47.2% to 95.0%). It would seem that increasing the storage capacity of the TES system beyond the maximum value considered in the analyses may have beneficial effects from the point of view of achieving even higher flexibility in changing the unit load (for a coal-fired unit, load modulation in the range from 41.0% to 100.0% is currently realized). On the other hand, further capacity expansion implies the need for increased capital expenditure, with a corresponding reduction in the average annual utilization rate of installed TES storage capacity, which is defined as follows:

$$\delta = \frac{Q_{\text{TES}}}{(Q_{\text{TES}})_{\text{max}}}, \quad (18)$$

where Q_{TES} is annual amount of thermal energy stored in the TES system, and Q_{TES} is maximum annual amount of thermal energy that can be stored in the TES system.

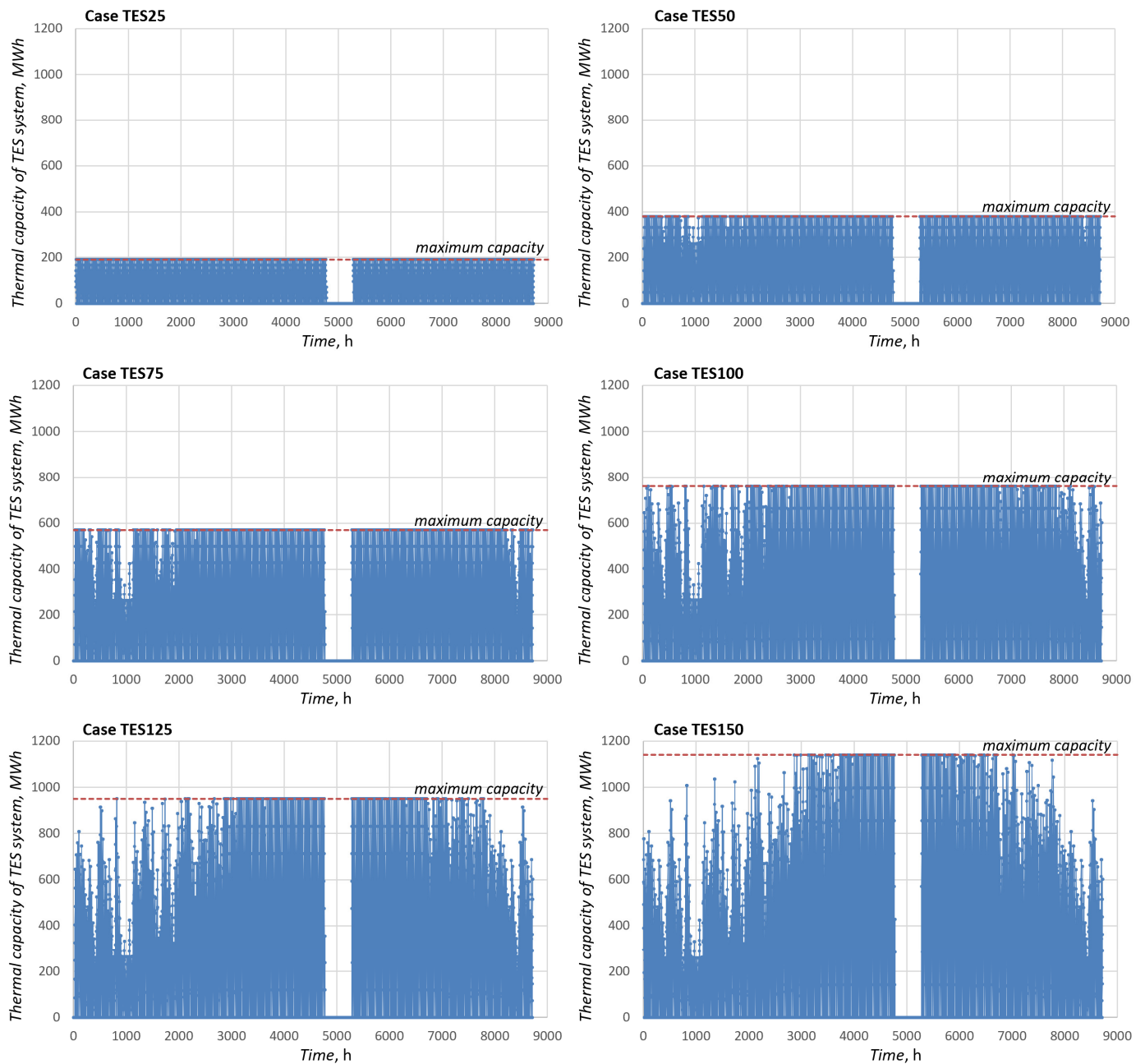


Figure 11. Thermal capacity of TES system as a function of time for reference year for all analyzed cases where TES is used.

The appropriate selection of the system capacity should be determined primarily by an economic analysis.

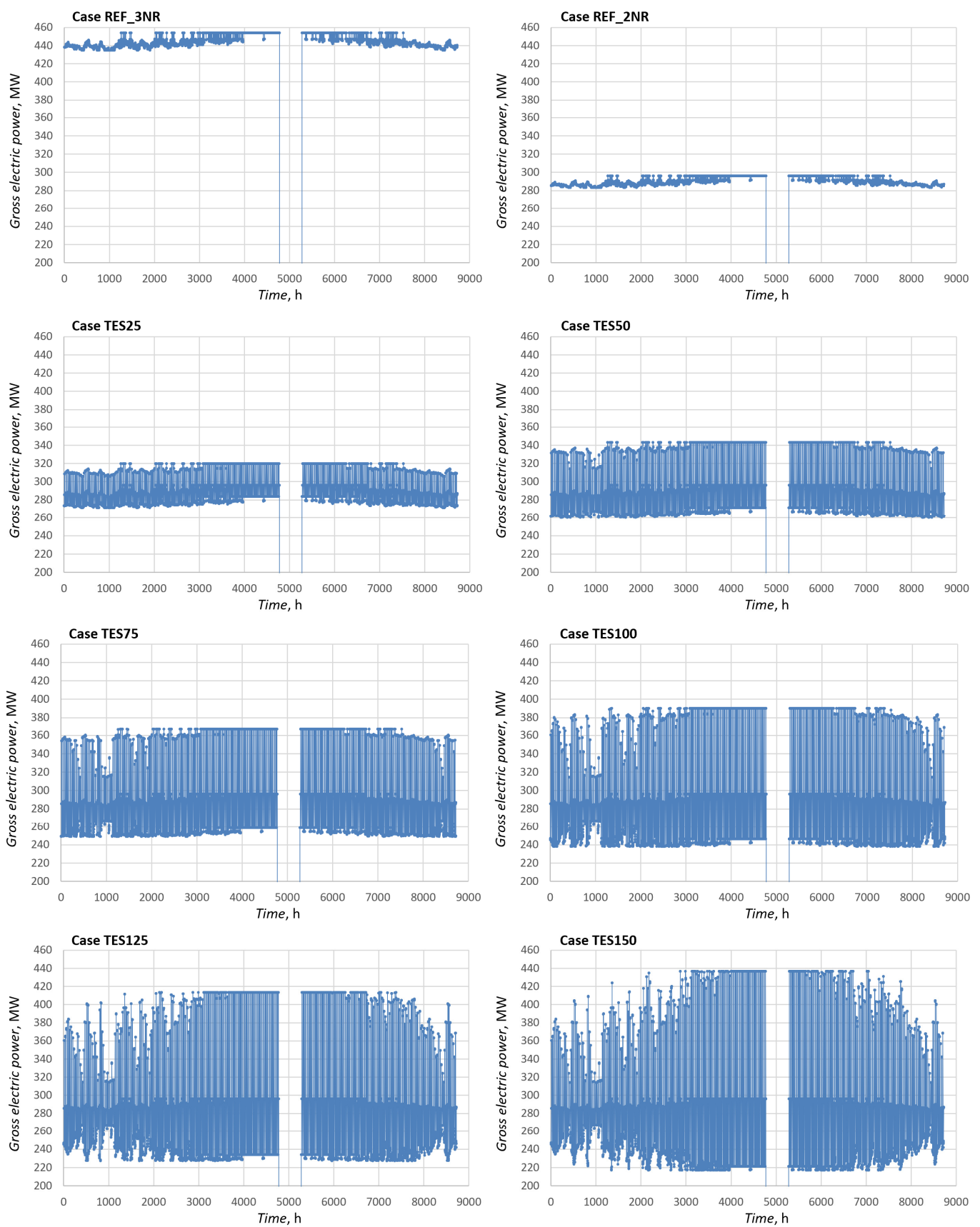


Figure 12. Gross electric power as a function of time for reference year for all analyzed cases.

The results obtained from the simulations of the nuclear units made it possible to determine technical-performance-evaluation indicators. The results of the analyses are presented in Table 3. As may be seen, the effect of applying TES can significantly shift the production of a high volume of electricity away from generation in the energy valley period, which is characterized by lower electricity prices. Energy production can be moved to the period of peak demand, where it is possible to sell this volume at a higher electricity price. The flexible operation of the unit will, itself, reduce the power price differences between peak and valley periods, particularly if this is performed on a large scale at multiple units; however, this feedback effect has not been included in this analysis. Table 3 also presents the values of the annual utilization rate of installed TES storage capacity, which was defined by Equation (18). While in the case of TES25 the capacity of the TES system is used 100% annually, the value of the indicator for the TES150 variant falls to 82.16%. The consequence of operating the steam turbine unit at a capacity lower than the nominal, as is the case in all variants with two nuclear reactors, is obtaining a lower thermal efficiency for the nuclear unit. Such efficiency is defined by the following relation:

$$\eta_t = \frac{E_{el,g}}{Q_{NRS}}, \quad (19)$$

where $E_{el,g}$ is the annual gross electricity production, and Q_{NRS} is the annual amount of thermal energy produced by the nuclear reactor system.

Table 3. Results of technical assessment of respective analyzed cases of nuclear retrofits.

	Case							
	REF_3NR	REF_2NR	TES25	TES50	TES75	TES100	TES125	TES150
TES capacity (w/o losses), MWh	0	0	200	400	600	800	1000	1200
Electricity peak-production, GWh	588.9	384.1	414.7	444.4	472.5	496.8	514.8	527.2
Electricity energy valley-production, GWh	1168.3	761.6	729.5	698.3	668.8	643.0	623.9	610.7
Other production, GWh	1760.9	1148.2	1148.2	1148.2	1148.2	1148.2	1148.2	1148.2
Total electricity production, GWh	3518.1	2293.9	2292.4	2290.9	2289.4	2288.0	2286.9	2286.1
Heat production, TJ	2026.4	2026.4	2026.4	2026.4	2026.4	2026.4	2026.4	2026.4
Utilization rate of installed TES storage capacity, -	-	-	1.0000	0.9867	0.9646	0.9226	0.8562	0.8216
Annual thermal efficiency, -	0.4645	0.4543	0.4540	0.4537	0.4534	0.4531	0.4529	0.4527

The highest average annual thermal efficiency was obtained for the reference case with three nuclear reactors used. This is primarily due to the favorable operating conditions of the steam turbine, which is close to its nominal load during the entire operating period. It indicates the high internal efficiency with which the steam turbine works (see Reference [4]) and, therefore, high operating efficiency. Reduction of the thermal load of the turbine significantly below its nominal load, which occurs in all variants with the system of two nuclear reactors applied, leads to the degradation of the steam turbine efficiency characteristics and, consequently, to a lower production of electricity per unit of heat supplied to the turbine cycle. The observed decrease in thermal efficiency associated with the increase in thermal capacity of the TES system is also due to the steam turbine internal efficiency obtained on an average annual basis. In this case, the lower thermal efficiency is also a result of heat losses identified within the TES system.

3.2. Results of Economic Analyses

The results of the economic analyses performed for all cases for the nominal assumptions are summarized in Table 4. Considering the NPVs calculated, the results indicate a significant advantage of the reference system with three nuclear reactors over the systems with two reactors. It should be noted that the REF_3NR option has a significantly

higher production potential and investment expenditure than the other options. From the investor's perspective, such an investment should also achieve higher economic efficiency expressed in absolute terms, as indicated by the results of the performed analyses. While the amount of upfront investment for REF_3NR was EUR 1.217 billion, the amount of investment for REF_2NR was EUR 0.811 billion.

Table 4. Results of economic analyses for nominal assumptions.

	Case							
	REF_3NR	REF_2NR	TES25	TES50	TES75	TES100	TES125	TES150
NPV, MEUR	2810.27	1874.06	1880.83	1887.03	1892.23	1895.29	1894.86	1891.28
Δ NPV, MEUR	-	-	6.77	12.97	18.17	21.23	20.80	17.22
DPP, years	8	8	8	8	8	8	9	9
DPP*, years	-	-	19	20	21	22	24	29
NPVR, -	2.309	2.310	2.288	2.266	2.243	2.218	2.190	2.159

The investment worthiness of TES can be found by comparing the NPVs of units with two nuclear reactors. In this context, the investment prospects do not differ significantly. This is due to the fact that the part of the investment required for the installation of the TES system represents a small share of the total investment, practically independent of the heat capacity of the TES system used. The capital expenditure for the TES25 case was EUR 0.822 billion, and for the TES150 case, it was EUR 0.876 billion. The highest value of NPV for the cases with two nuclear reactors was achieved for the TES100 variant, thus indicating that it would be most beneficial to install an 800 MWh TES system alongside the two reactors. This value is higher than the value obtained for the REF_2NR case by MEUR21.23. Generally, the cases of nuclear units equipped with TES systems with higher capacities obtain an economic advantage over the reference system and the cases of units with TES systems with lower capacities for the nominal operating time, i.e., after 50 years of operation. This may not be so evident for shorter operating lifetimes. This is demonstrated by the values obtained for the discounted payback period. As it was presented in Table 4, the DPP index for variants TES125 and TES150 is higher by 1 year than for the other analyzed cases. The results of the analyses performed for nominal assumptions in terms of obtained values for the NPVR index indicate that the most advantageous option is the REF_2NR variant. With small relative deviations of the electricity prices ($-0.2/0.2$) for the individual operating periods from the perspective of the obtained values for the NPVR, the installation of TES is not recommended, regardless of its thermal capacity. The payback time of the TES part of the investment is long, ranging from 19 years (TES25) to 29 years (TES150) for the cases analyzed.

Figure 13 presents the characteristics of the NPV ratio as a function of the lifetime of the investment object. The three sets of characteristics show the case for three different values of relative deviations of electricity prices ($-0.2/0.2$, $-0.5/0.5$, and $-0.8/0.8$). Although higher values of deviations would not contribute to significant reductions in the value of discounted payback periods, certainly greater variation in the market price of energy over the day cycle would very significantly improve the economic efficiency of units equipped with TES systems with higher thermal capacities. This is shown in Figure 14, where the characteristics of the Δ NPV index as a function of the thermal capacity of the TES system for different values of the price deviation index were compared. For example, an investment in a TES system with the highest heat capacity analyzed (1200 MWh), with deviation values of -0.8 and 0.8 , will allow for a profit that is higher by about 15.0% (MEUR281). As shown in Figure 15, where the characteristics of the Δ NPV indicator are compared as a function of the lifetime of the object of investment, extending the operational lifetime to 60 years would allow the profit level resulting from the TES system to exceed MEUR300. However, in this situation, the relative increase is lower and results in being 14.8%. As Figure 16 demonstrates, from the point of view of NPV to be acceptable to investors, TES within a nuclear unit requires a market situation in which the deviation ratios are at least -0.2

and 0.2. A higher deviation than the nominal deviation assumed in the analyses creates conditions in which it is worthwhile to use TES systems with the highest capacity. Slightly different conclusions are achieved by taking maximization of the value for the *NPVR* as the evaluation criterion. This is clearly illustrated in Figure 16, where the values of this index are presented as a function of the capacity of the TES system for different values of the deviation index. From the point of view of *NPVR* increment, the application of TES is reasonable for values of deviation ratios lower than -0.5 and higher than 0.5 , respectively, but in each case of the analyzed values of deviation ratios, it is not reasonable to apply TES with the highest capacity. This implies that there is an adverse effect of over-sizing the TES systems. This problem occurs even for the highest energy price differential considered ($-1.0/1.0$). Figure 17 shows the characteristics of the *NPVR* as a function of the lifetime of the investment subject for all the cases analyzed. The comparisons concern, as shown in Figures 13 and 15, three pairs of values of energy price deviation ratios, i.e., $-0.2/0.2$, $-0.5/0.5$, and $-0.8/0.8$. For the value $-0.5/0.5$, the individual cases of nuclear units with two nuclear reactors are characterized by similar values of *NPVR*. For values of deviation ratios $-0.2/0.2$, on the other hand, we observe the adverse effect of increasing the thermal capacity of the TES system. In contrast, for the value of deviation ratios $-0.8/0.8$, the trend is the opposite—the greater the capacity, the greater the value of *NPVR* index becomes.

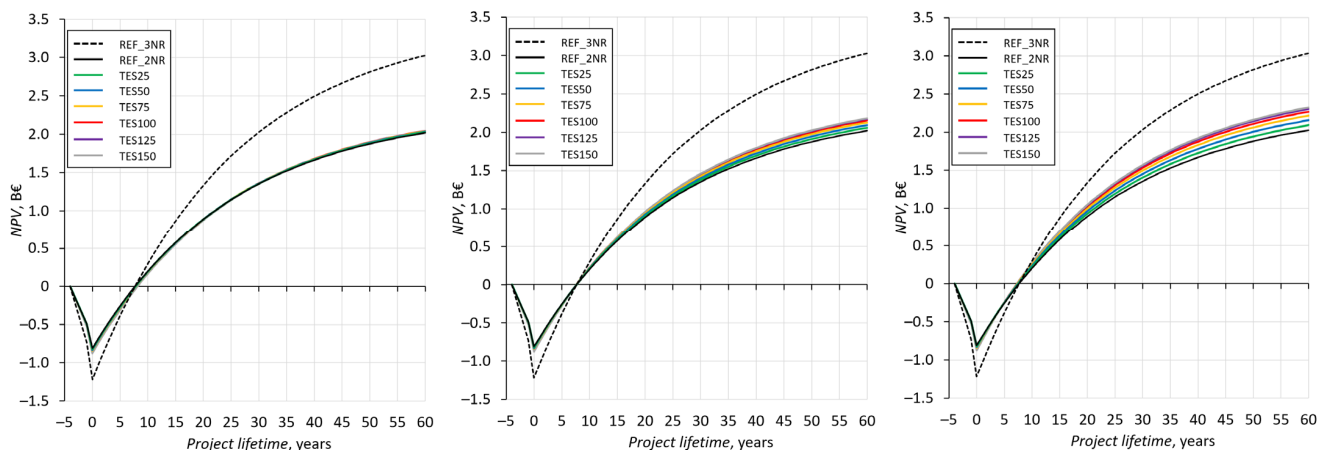


Figure 13. NPV as a function of project lifetime for the three values of deviation index (left = $-0.2/0.2$, central = $-0.5/0.5$, and right = $-0.8/0.8$).

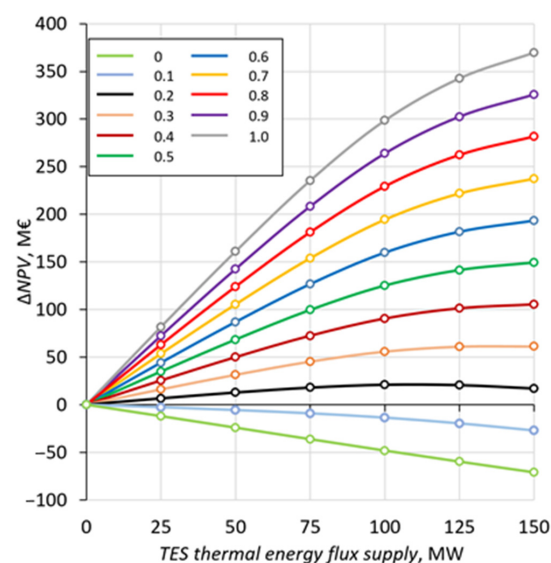


Figure 14. Δ NPV as a function of TES thermal energy flux supply for the eleven values of deviation index (from 0 to 1, with step 0.1).

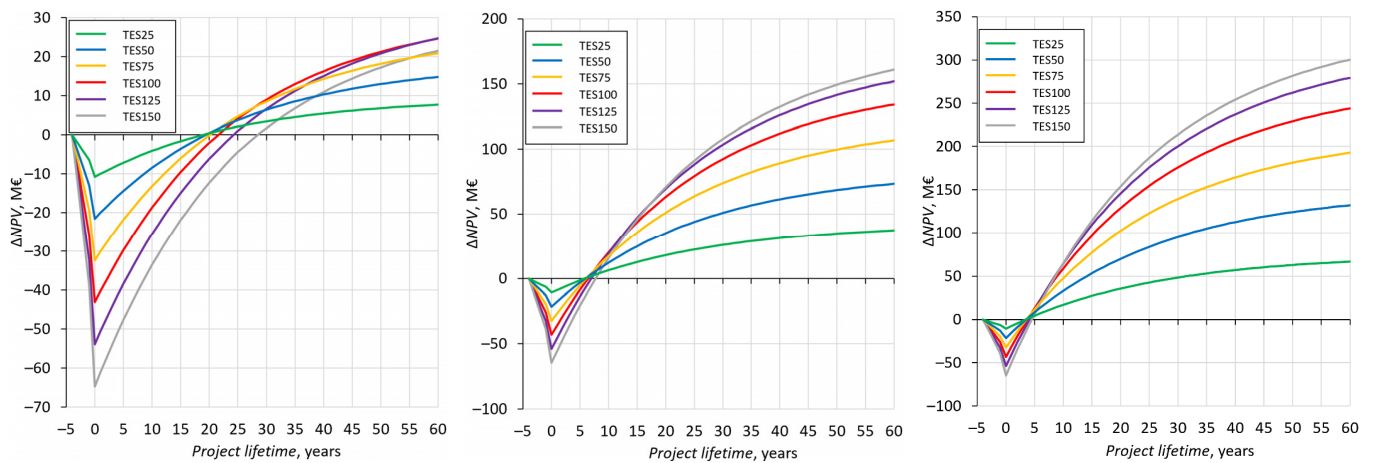


Figure 15. ΔNPV as a function of project lifetime for the three values of deviation index (left = $-0.2/0.2$, central = $-0.5/0.5$, and right = $-0.8/0.8$).

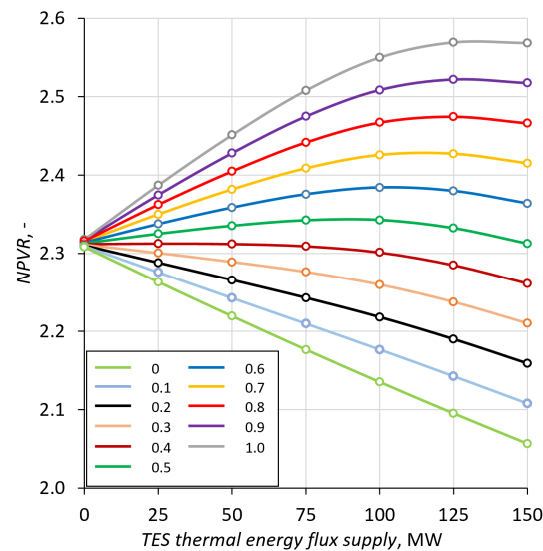


Figure 16. $NPVR$ as a function of TES thermal energy flux supply for the eleven values of deviation index (from 0 to 1, with step 0.1).

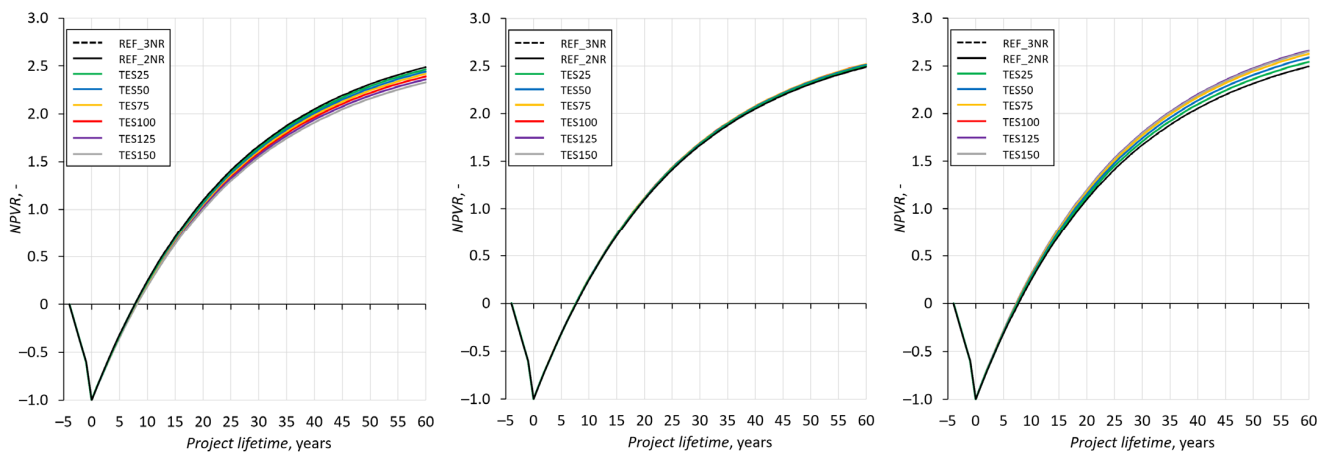


Figure 17. $NPVR$ as a function of project lifetime for the three values of deviation index (left = $-0.2/0.2$; central = $-0.5/0.5$, and right = $-0.8/0.8$).

4. Discussion

In light of the analysis results presented in this paper, it seems that nuclear units integrated with TES systems will become increasingly interesting over time, and this should be associated with the expected intensification of problems related to power system balancing. This is related to the expected increase in the installed capacity of intermittent renewable sources in Europe, including Poland, and the new higher cost level for gas. In this situation, the driving force for integrating nuclear units with TES systems will be the increasing differentiation of electricity prices in periods of energy valleys and peak demand, which may, in the future, be driven more by whether it is sunny or windy rather than whether it is day or night. During current market conditions, among the analyzed cases, the most attractive investment is the one with two nuclear reactors and a TES system with a capacity of 800 MWh. The results of the analysis indicate, however, that with the expected increase in price volatility, it will be reasonable to use larger systems with capacities ranging from 1000 to 1200 MWh. The results indicate that oversizing the TES system above these capacity values will lead to unfavorable economic effects for the investor unless price volatility increases further. The use of the TES system with the highest analyzed thermal capacity, however, allows the power of the steam turbine to approach the nominal value of 460 MW, and thus also to the possibility of periodic use of the turbine's full production potential.

The results of the conducted analysis show that the integration of nuclear units with TES systems may allow for a significant increase in the flexibility of electricity production with the simultaneous full use of the production potential of nuclear reactors, and this is desirable due to the significant share of purchase costs of reactors in the total investment costs. Higher flexibility is an attractive feature for a dispatchable power unit operating in a market with increases shares of intermittent renewable generation. From the economic point of view, the high effectiveness of the integration of nuclear units with TES systems is determined by the relatively low investment costs required for the construction of the TES system. According to the estimates made, the investment outlay for the TES system with the highest capacity is only 7.4% of the total investment outlay for the power unit. Subsequent analyses for the systems discussed in this publication should focus particularly on the issue of operational safety. In future work, the authors intend to perform optimization of TES systems in different market scenarios in a more realistic way, by modeling their operation as dictated by the electricity price in the market changing with different dynamics.

5. Conclusions

The coal-fired power units currently operating in Poland are crucial for the country's energy security. They are especially important due to their ability to provide regulation and balancing in the power market. Thanks to these regulating units, the system still maintains satisfactory flexibility to adapt the current production to the actual demand, even with the growing installed capacity of intermittent sources such as photovoltaic installations and wind turbines. In the upcoming two decades, Poland is expected to launch offshore wind farms (11 GW by 2040) and remove obstacles to investments in onshore wind facilities. It is also planning to expand the development of solar installations. Currently, from 2033 onward, Poland intends to commission nuclear power plants, whose final installed capacity in 2043 is expected to be between 6 and 9 GW. Considering the dynamic turn toward green energy, replacing coal-fired sources with other dispatchable and flexible low-carbon sources will be a key challenge. So far, in Europe, in regions lacking abundant reservoir hydroelectric capacity, flexibility is provided by gas-fired power plants. However, Russia's invasion of the Ukraine has forced a review of energy policies. Europe has accelerated the plans for becoming independent of fossil-fuel supplies from the east. This process poses a risk for investments in the gas power industry, both due to the lack of guaranteed supply and higher expected prices. The current situation forces the need to find ecological solutions that are cheap in operation and capable of responding flexibly to

the demands of power system operators. Potentially, nuclear units integrated with molten salt heat storage systems can provide such a capability.

Many coal-fired units in Poland will be decommissioned not only due to the need to meet decarbonization demands but also due to their technical condition. Potentially, the newest supercritical coal-fired units operating in Poland that were commissioned in recent years could decarbonize along the Coal-to-Nuclear pathway in the early 2030s. The integration of such systems with TES systems, as demonstrated in this paper, could enable decarbonization while maintaining high flexibility to change turbine island loads. The results of the analysis presented in this study show that TES systems intended for integration with nuclear systems should be analyzed by decision-makers in parallel with other popular large-scale energy storage systems. This is due to their favorable technical characteristics, as well as their high economic effectiveness. The analysis indicates that equipping nuclear power units with TES systems may help facilitate energy mixes based almost entirely on nuclear and intermittent renewable sources, without the need for high shares of gas energy in the mix.

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Appendix A

Table A1. Results of validation of steam island model.

Measurement Number		1	2	3	4	5	6	7	8	9	10	11	12	13	14
District Heating Network Heat Demand, MW		0	0	0	0	0	30	30	30	30	50	50	50	50	130
Live steam mass flow, kg/s	Report	358.69	331.32	268.01	213.73	142.2	363.71	329.08	255.75	184.55	360.22	328.81	256.96	186.19	362.14
	Model	358.47	331.53	268.1	213.44	142.04	364.62	329.17	256.05	184.76	360.31	328.71	257.05	186.36	362.13
Relative error, %		−0.06%	0.06%	0.03%	−0.13%	−0.12%	0.25%	0.03%	0.12%	0.12%	0.03%	−0.03%	0.04%	0.09%	0.00%
Live steam pressure, kPa	Report	28,127	26,846	23,381	20,269	15,640	27,954	26,673	22,568	18,183	27,942	26,743	22,650	18,180	27,758
	Model	28,113.2	26,819.7	23,478	20,213.8	15,294.2	28,326	26,626.9	22,712.7	18,263.8	28,060.1	26,538.2	22,706.7	18,314.2	27,752.7
Relative error, %		−0.05%	−0.10%	0.41%	−0.27%	−2.21%	1.33%	−0.17%	0.64%	0.44%	0.42%	−0.77%	0.25%	0.74%	−0.02%
Reheated steam mass flow, kg/s	Report	306.78	284.24	233.89	189.56	128.93	310.92	283.08	222.96	163.6	307.04	282.6	224.46	164.21	307.27
	Model	306.14	284.97	234.03	188.71	127.1	310.77	282.91	223.94	164.11	307.21	282.36	224.58	165.29	307.27
Relative error, %		−0.21%	0.26%	0.06%	−0.45%	−1.42%	−0.05%	−0.06%	0.44%	0.31%	0.06%	−0.09%	0.05%	0.66%	0.00%
Reheated steam pressure, kPa	Report	4907	4518	3761	3030	2041	4959	4524	3586	2601	4865	4511	3598	2624	4891
	Model	4879.8	4555.7	3760.3	3032.6	2010.4	4933.9	4508.6	3586.3	2617.7	4874.4	4494.6	3591.3	2632.7	4893.8
Relative error, %		−0.55%	0.83%	−0.02%	0.09%	−1.50%	−0.51%	−0.34%	0.01%	0.64%	0.19%	−0.36%	−0.19%	0.33%	0.06%
Feedwater mass flow, kg/s	Report	350.23	316.07	243.77	199	128.8	360.21	313.97	232.38	166.88	359.33	322.7	241.77	169.85	356.28
	Model	348.23	317.26	247.79	192.38	127.65	362.31	320.77	240.02	168.9	359.54	322.41	242.84	171.79	354.9
Relative error, %		−0.57%	0.38%	1.65%	−3.32%	−0.90%	0.58%	2.17%	3.29%	1.21%	0.06%	−0.09%	0.44%	1.14%	−0.39%
Feedwater temperature, °C	Report	310.2	308.1	309.3	310.6	312.8	311	309.7	309.8	311.1	308.9	309.4	309.8	311.2	309.4
	Model	309.33	309.25	309.56	310.46	312.72	309.16	309.09	309.59	311.12	309.09	309.04	309.57	311.08	309.41
Relative error, %		−0.28%	0.37%	0.09%	−0.04%	−0.03%	−0.59%	−0.20%	−0.07%	0.01%	0.06%	−0.12%	−0.08%	−0.04%	0.00%
Gross power, MW	Report	452.34	419.73	350.32	281.17	189.65	452.58	413.01	329.81	238.98	444.48	407.78	326.47	236.67	434.02
	Model	451.53	421.48	347.76	280.38	185.8	452.14	413.08	328.45	239.65	443.8	409.15	326.79	239.47	434.16
Relative error, %		0.18%	−0.42%	0.73%	0.28%	2.03%	0.10%	−0.02%	0.41%	−0.28%	0.15%	−0.34%	−0.10%	−1.18%	−0.03%
Thermal power of SB, MW	Report	948.98	884.11	738.27	603.35	417.25	960.48	881.11	706.57	526.75	950.19	879.44	710.31	531.13	954.8
	Model	949.13	883.88	738.24	602.84	416.23	962.04	881.39	707.39	527.07	950.25	879.4	710.55	531.82	954.82
Relative error, %		−0.02%	0.03%	0.00%	0.08%	0.24%	−0.16%	−0.03%	−0.12%	−0.06%	−0.01%	0.00%	−0.03%	−0.13%	0.00%
Thermal efficiency of STU, %	Report	47.67	47.47	47.45	46.6	45.45	47.12	46.87	46.68	45.37	46.78	46.37	45.96	44.56	45.46
	Model	47.57	47.68	47.11	46.51	44.64	47	46.87	46.43	45.47	46.7	46.53	45.99	45.03	45.47
Relative error, %		0.20%	−0.44%	0.73%	0.20%	1.79%	0.26%	0.01%	0.53%	−0.22%	0.16%	−0.34%	−0.06%	−1.05%	−0.03%

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