energies

Review

Evaluation of Coal Repowering Option with Small Modular Reactor in South Korea

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Abstract: The Paris Agreement emphasizes the need to reduce greenhouse gas emissions, particularly from coal power. One suggested approach is repowering coal-fired power plants (CPPs) with small modular reactors (SMRs). South Korea plans to retire CPPs in the coming decades and requires alternative options for coal-fired energy. This study presents a scoping analysis comparing variable renewable energy (VRE) sources with SMRs for repowering CPPs in the Korean context. The analysis indicates that SMRs may be a more favorable option than VRE sources, particularly due to their load-following capabilities. In this study, two types of SMRs were investigated: high-temperature gas reactors (HTGRs) and pressurized water reactors (PWRs). HTGRs are suitable to fit the high-temperature operating conditions of steam turbines but require multiple units due to their low volumetric flow rates. PWRs, while matching the volumetric flow rate of existing CPP turbines, require additional thermal energy sources to meet the high-temperature operating conditions of steam turbines. Lastly, an analysis of necessary regulatory and legislative changes in South Korea's nuclear framework is presented, identifying several key regulatory issues for repowering coal with nuclear energy.

Keywords: small modular reactor; coal repowering; renewable energy; regulatory system of nuclear power plant

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1. Introduction

The Paris Agreement is an international treaty adopted by 195 countries to address climate change adaptation and mitigation. The primary aim of the agreement is to limit the global average temperature increase to well below 2 °C above pre-industrial levels while pursuing efforts to restrict the rise to 1.5 °C. All participating countries are required to set nationally determined contributions (NDCs) every five years, outlining the actions they will take to meet the treaty's objectives. In 2018, South Korea suggested a 40% reduction in greenhouse gas emissions by 2030 as part of its NDC under the Paris Agreement.

Coal-fired energy is one of the most dominant energy sources globally and accounts for 32% of South Korea's total electricity demand [1]. Given the high greenhouse gas emissions associated with coal-fired energy, 820 g of CO_2 per kWh of electricity produced, it is clear that coal power generation plays a significant role in the greenhouse gas emissions of South Korea's power generation sector (Figure 1) [2].

Despite the significant contribution of coal-fired energy to greenhouse gas emissions, the decommissioning of currently operating coal-fired power plants (CPPs) is an unrealistic option, given the increasing electricity demand of modern society. Therefore, methods to reduce the proportion of coal-fired energy in total electricity production, without reducing overall generation capacity, are necessary. One such approach is "coal repowering," which means replacing the energy sources of CPPs with low-carbon alternatives.

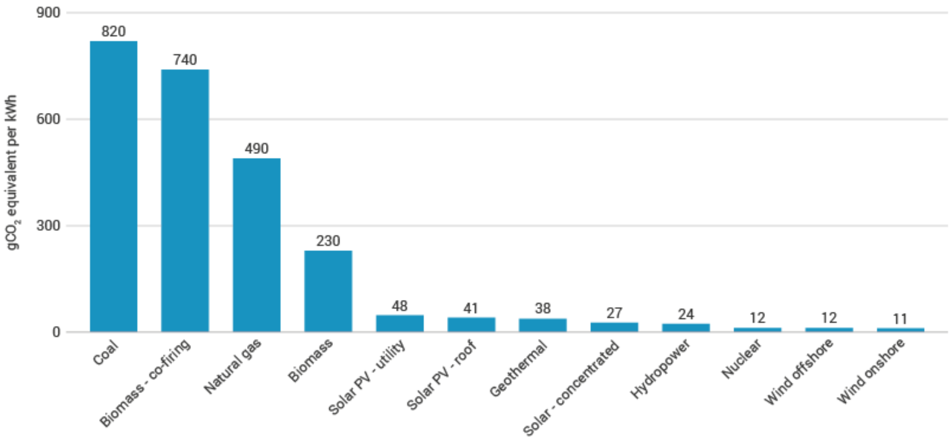


Figure 1. Average life cycle CO_2 equivalent emissions (source: IPCC) [2].

Among various alternative sources, repowering CPPs with nuclear energy has emerged as a promising solution to reduce greenhouse gas emissions while utilizing existing infrastructure. Due to the significantly low CO_2 emissions of nuclear power plants, nuclear energy can play a key role in decarbonizing the energy system. L. Duan et al. (2020) explored the role of nuclear energy in deeply decarbonized electricity systems dominated by wind and solar resources [3]. They provided a stylized least-cost analysis that highlights the importance of flexibility in nuclear operations. The study found that integrating flexible nuclear power enhances the stability of grids with high renewable penetration, reducing overall system costs and improving reliability. These findings emphasize the complementary role of nuclear energy alongside intermittent renewables in achieving decarbonization goals.

Among various coal-to-nuclear options, many studies have focused on scenarios involving repowering with small modular reactors (SMRs). SMRs are a class of advanced nuclear reactors with an electricity generation capacity of up to 300 MWe per unit. Compared to conventional large-scale commercial nuclear reactors currently in operation, SMRs offer advantages such as smaller physical size and modular construction enabled by factory-based assembly. Given these characteristics, SMRs can serve as an alternative energy source for repowering CPPs. Łukowicz et al. (2023) analyzed the repowering of CPPs using modular light-water reactor technology, focusing on retrofitting existing steam cycles [4]. Their findings highlight that repowering with SMRs, particularly with modifications tailored to optimize turbine compatibility, offers a cost-effective and technically feasible pathway for decarbonizing relatively modern coal plants. In China, a study by S. Wu et al. (2022) outlined a strategic framework for replacing coal boilers with high-temperature gas-cooled reactor-pebble-bed modules (HTR-PM) [5]. The proposed implementation stages focused on leveraging existing coastal coal power infrastructure to achieve cost-effective decarbonization while addressing stranded assets. This research highlights the feasibility of nuclear retrofitting as a scalable approach to transition toward a low-carbon power sector. L. Bartela et al. conducted a study on the techno-economic feasibility of retrofitting CPPs with Kairos Power fluoride-salt-cooled high-temperature reactor (KP-FHR) [6]. This analysis emphasized the dual benefits of substantial carbon emissions reduction and improved operational efficiency. This study underscores the role of advanced nuclear technologies in enhancing the economic competitiveness of decarbonized energy systems. This study shows that retrofitting existing coal plants with Kairos Power SMRs can reduce costs by up to 35% compared to greenfield investments, offering a viable economic and technical solution. The analysis highlights a 460 MW retrofit scenario with a favorable NPV advantage of €556.9 million and a 10-year payback period, demonstrating the retrofit's feasibility. Similarly, a comprehensive economic assessment conducted by B. Luo et al. (2021) evaluated the economic viability of retrofitting CPPs with high-temperature gas-cooled reactors (HTGRs) [7]. Their results showed that the coal-to-nuclear total capitalized costs (USD 5297.6/kW) are 19.4% lower than the greenfield project (USD 6576.5/kW).

The potential of coal-to-nuclear transitions has been analyzed in various countries worldwide, and its technical and economic feasibility has been positively evaluated. However, a comprehensive analysis comparing repowering possibilities with nuclear and other energy sources has not yet been conducted specifically for South Korea. With this background, this study aims to comprehensively examine various repowering options for Korea. Instead of focusing on the economic feasibility of a specific nuclear reactor type, the study evaluates how nuclear power compares to other energy sources in terms of installation capacity. Additionally, it explores which SMR designs align with the thermodynamic conditions of Korea's CPPs and identifies the groundwork needed from a regulatory perspective.

The paper is organized as follows: Section 2 calculates the installed capacity required to replace thermal power plants with either variable renewable energy (VRE) or SMRs, demonstrating that SMRs can achieve comparable power output with significantly smaller installed capacity when compared to VRE. Section 3 identifies potential CPP candidates for repowering and outlines conditions based on their steam cycle characteristics. Section 4 explores suitable SMR types for repowering under these conditions, conducting thermodynamic analyses on selected pressurized water reactors (PWRs) and high-temperature gas reactors (HTGRs). Section 5 examines the potential regulatory challenges associated with repowering using SMRs. Finally, Section 6 provides a summary and review of the study. This research is expected to offer valuable insights for stakeholders and policymakers interested in coal repowering in environments similar to South Korea.

2. Required Capacity of Variable Renewable and Nuclear for Coal Repowering

2.1. Challenges in Replacing Coal-Fired Energy with Renewable Energy

In selecting a low-carbon energy source for repowering of CPPs, several aspects in power generation have to be considered, which include cost, installed capacity, grid connectivity, and carbon emissions. Undoubtedly, replacing coal with renewables or nuclear power at these sites would result in a substantial reduction in carbon emissions [8]. To reduce carbon emissions, South Korea has been relying more on renewable energy in electricity generation. Solar photovoltaic (PV) and wind energy, collectively referred to as VRE, have gained the spotlight over the past decade [9].

In the electricity market, it is crucial that the supply and demand of electricity be balanced at all times. When it comes to VRE, however, it is difficult to balance the supply and demand of electricity due to their inherent intermittency. Thus, satisfying the electricity demand with VREs instead of CPPs becomes a challenging task. Tang et al. have shown in their work that the increased installation of distributed VRE and storage may decrease the robustness of the transmission system [10]. This highlights the fact that the current grid control strategy may need to be revised to prepare for the deep penetration of VRE systems. Although this can be partially handled by installing battery-based energy storage systems, today's commercially available batteries are challenged to operate economically when supplying electricity to the large grid [11]. Thus, the integration of VREs into the current power grid system leaves undesirable vulnerabilities that need to be solved.

When installing new power plants, it is important to optimize the installed capacity (or nameplate capacity) of the alternative energy source to meet the supply and demand of electricity. If the required installed capacity is larger than the original CPP's installed capacity, the power transmission system should be increased in parallel. In fact, expanding the transmission infrastructure requires significant financial investment and faces grave public acceptance issues. Also, securing rights-of-way for new transmission lines can be challenging, particularly in densely populated areas or areas with competing land uses such as agriculture or conservation, as in South Korea.

Figure 2 depicts the power grid of South Korea. It shows concentrated transmission facilities in the densely populated northwest and in the southeast, where thermal and nuclear power plants are prevalent. If renewable energy installations are evenly distributed in areas lacking large power plants, it would enable decentralized electricity supply. However, the required addition of transmission facilities will inevitably increase costs. According to the "10th Long-Term Transmission and Substation Facility Plan" announced by the Korean government, expanding transmission facilities to accommodate renewable energy will cost about USD 41 billion [12]. Table 1 summarizes the number of transmission lines and substations required for this expansion, along with the associated costs. Therefore, the increment in costs due to the expansion of transmission facilities is likely to impact consumer electricity prices. Hence, it is desirable to minimize the increase in the installed capacity when replacing CPPs with alternative energy sources.

Figure 2. Power grid system of South Korea (cited from International Energy Agency, available at https://www.iea.org/articles/korea-electricity-security-policy (accessed on 28 April 2024).

Table 1. Rough budget for the transmission/distribution facility expansion project.

	765 kV	345 kV	154 kV	HVDC	Total
Total investment [billion USD]	0.13	15.41	13.89	11.51	40.94
Transmission lines [C-km]	8	7744	12,153	2586	22,491
Substations	1	48	266	21	336
Substation capacity [MVA]	12,000	58,500	36,620	61,800	168,920

In this light, the objective of this study is to evaluate alternative energy sources for CPP replacement, focusing on minimizing the increase in installed capacity while producing the same amount of energy to alleviate potential strains on the power transmission system. The candidates for the low-carbon energy sources will be limited to solar PV, wind, and SMRs in this study. It should be noted that the cost analysis of each power source is not in the scope of this study. The analysis is done in South Korea only, using the latest data for the year 2023.

This section is organized as follows: First, the installed capacity required to replace CPPs with VRE or SMRs is calculated. Since the electricity production from VRE cannot be manually controlled, the energy storage system (ESS) can be introduced to match the electricity supply and demand. In a scenario where CPPs are replaced by VRE, the required capacity of ESS is calculated. From this analysis, the competitiveness of VRE and SMRs in replacing the electricity production of CPPs is evaluated.

2.2. Background and Assumptions

In determining the installed capacity of a power plant, the key is to find the optimum capacity that meets the electricity demand of that country or region. As this study is focused on repowering CPPs, the amount of electricity generation from CPPs will be the target, not the actual electricity demand.

Although there are various fuel types used for fossil fuel plants, this paper will focus on CPPs burning bituminous coal. Figure 3 shows the portion of fuel types for fossil fuel plants in South Korea. The installed capacity of bituminous coal and liquid nitrogen gas (LNG) is 40,290 and 43,953 MW, respectively, together taking up more than 97% of the total installed capacity of fossil fuel in power generation sector [13]. Other fuel types, such as diesel, hard coal, and bio-heavy oil, will not be considered in this analysis, as their contributions are less substantial.

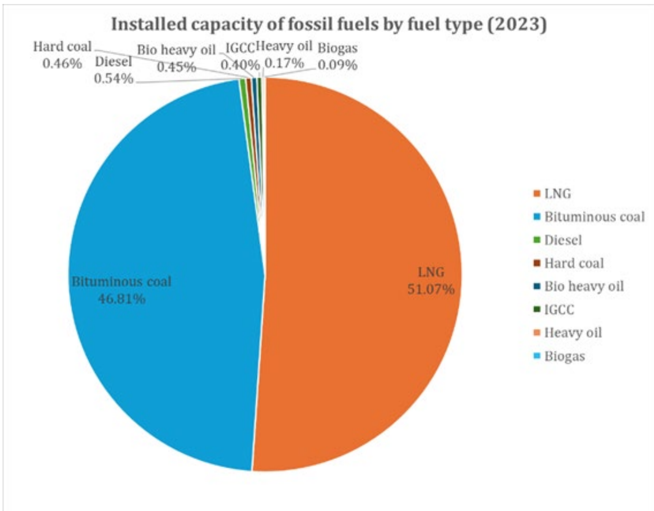


Figure 3. Installed capacity of fossil fuels by fuel type (2023).

The data for electricity generation from bituminous coal CPPs is obtained for the evaluation. The time resolution of the electricity generation profile varies from annual to monthly, daily, and hourly basis. Increasing the time resolution of the profile is important, as this study addresses hypothetical scenarios in which CPPs are replaced with VRE, of which electricity generation profile is highly time-variant due to its intermittency. The hourly electricity generation from CPPs in 2023 was obtained from Korea Power Exchange (KPX). The installed capacity of CPPs in that period is given in Table 2, ranging from 39 to 40 GW.

Table 2. Actual installed capacity of CPPs in South Korea, 2023.

Date	Actual Installed Capacity [MW]
~August 2	39,181
August 3~9	40,231
August 10~	40,290

2.3. Calculation of Installed Capacity of Alternative Power Source

When replacing CPPs with different power sources, the required installed capacities vary due to each source's different capacity factors. The capacity factor indicates how efficiently each power source can operate throughout the year (see Equation (1)). From this definition, the equation for estimating the average installed capacity (IC_s) required to substitute CPPs with a different power source, s, can be derived (see Equation (2)). The annual electricity generation from CPPs is divided by the capacity factor of the alternative source (cf_s) and the total hours in a year (=8760 h). The annual CPP generation is obtained by summing up the 2023 coal-fired power generation profiles.

$$\text{capacity factor} = \frac{\text{Annual generation}[\text{MWh}]}{\text{installed capacity } [\text{MW}] \times 8760 \text{ h}} \quad (1)$$

$$\text{IC}_\text{s} \ [\text{MW}] = \frac{\text{Annual electricity generation from CPP } [\text{MWh}]}{cf_s \times 8760 \text{ h}} \quad (2)$$

For the capacity factor of VRE, the average capacity factor measured in South Korea from 2013 to 2022 was used. Figure 4 shows the capacity factors of solar PV and wind power generation by year. On average, solar PV operated at a 0.13 capacity factor, while wind power operated at a 0.2 capacity factor. SMRs, on the other hand, the actual capacity factor, is not known since it is under development stage. As South Korea does not have the experience of operating SMRs, it is challenging to determine an accurate capacity factor. Instead, it is possible to refer to large-scale nuclear power plants capable of load-following operations. France is a representative country operating large nuclear power plants for load-following. This study assumes that the capacity factor of French nuclear plants is equivalent to that of SMRs. As of 2023, France's nuclear power plants had a capacity factor of approximately 67.3%, which is lower than the 80.2% observed for South Korea's baseload nuclear plants [14]. This capacity factor value was used to calculate the installed capacity for SMRs.

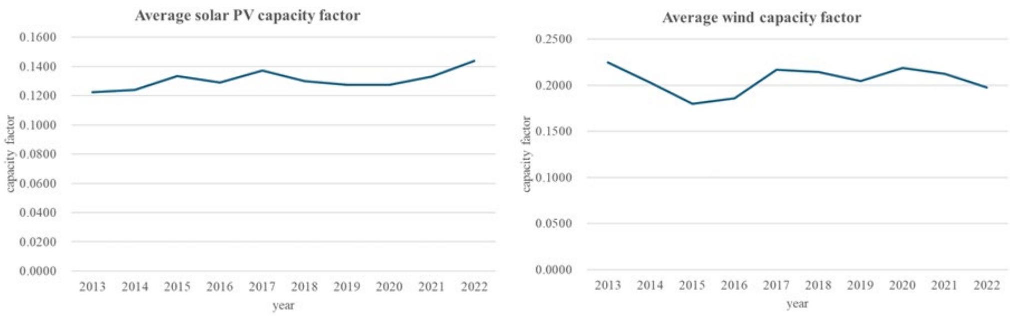


Figure 4. Average capacity factor of solar PV and wind, 2013–2022.

Before directly applying Equation (2) to the replacement scenario with SMRs, the load-following capability of SMRs should be investigated. SMRs are relatively easier to control the power, as they are not constrained to external environments, such as weather or geographic conditions. Due to this characteristic, a baseload operation like CPPs is possible.

CPPs are known for a flexible operation, as the power can be controlled by simply adjusting the amount of coal being supplied to the combustion chamber. Although the CPPs serve as baseload energy source in a large time frame, their power generation varies on an hourly basis to satisfy the energy demand. Thus, it should be investigated whether the degree of load-following of CPPs is manageable with SMRs. To do so, the maximum ramp rate from the CPP generation profile and the ramp rate limit of SMRs should be compared.

The ramp rate limit of a nuclear power plant varies depending on the reactor type, load-following scheme, safety limits, and technical specifications. Among various SMR types, the PWR-type SMR is being most actively developed worldwide. Therefore, this study aims to analyze based on the ramp rate of PWR-type SMRs. According to the IAEA SMR booklet [15], the maximum ramp rate of PWR-type SMRs is expected to be 2–5% per minute.

Using the hourly coal power generation profile, the power ramp rate can be estimated. Since there is no power generation profile with sub-hourly time resolution, the hourly profile is used at best. Using Equation (3), the hourly ramp rate(t) of CPP-generated electricity can be calculated for the year 2023. The ramp rate detailed in Equation (3) was derived from the cumulative power generation of all thermal power plants in South Korea. If the ramp rate had been calculated based on the power generation of individual units, it is probable that the ramp rate would have been higher.

$$\text{ramp rate}(t)[\%/h] = \frac{\text{coal generation}(t+1) - \text{coal generation}(t)}{1h} \tag{3}$$

From Figure 5, it is observed that the maximum ramp rate of South Korea's electricity generation from CPPs was 7.32% per hour. This is converted into 0.12% per min on average, which is significantly lower than the ramp rate limit of SMRs. Thus, it is inferred that SMRs can follow the load-following profile of CPPs in South Korea and that it is possible to directly apply Equation (2) for estimating the installed capacity of SMRs for replacing CPPs.

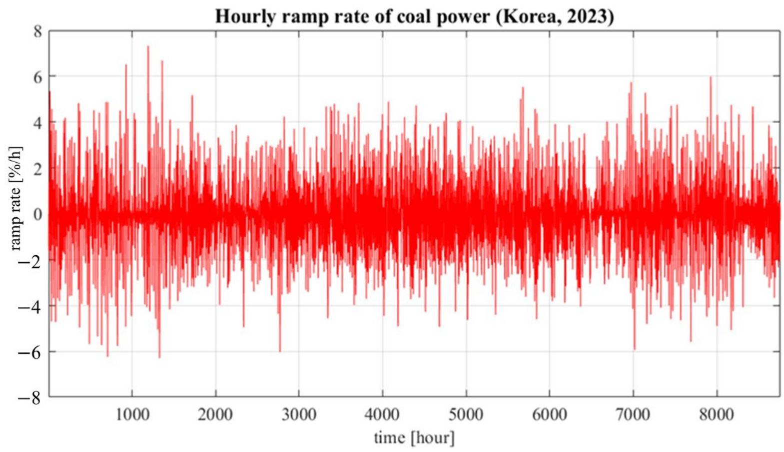


Figure 5. Hourly ramp rate of coal power in South Korea, 2023.

Using the capacity factors outlined above, the required amount of installed capacity for replacing CPPs with each energy source is calculated and summarized in Figure 6. It is observed that solar PV and wind energy require more than triple and twice the installed capacity of CPPs, respectively. This is due to the low capacity factors of VREs. On the other hand, SMRs require an installation of 29.23 GW, a scale smaller than CPPs. This value is comparable to the actual installed capacity of large commercial nuclear power plants in South Korea, which amounts to 26.1 GW in 2023. It implies that a similar amount of SMR capacity as that of current large nuclear power plants is required to completely replace the CPPs in South Korea. In conclusion, it has been quantitatively proven that substantially larger installed capacity of solar PV and wind is required to replace coal compared to SMRs. This indicates that utilizing solar PV and wind power will further provide pressure to increase the capacity of the transmission line in South Korea, which will be another salient issue to deal with for the expansion of VRE sources under the South Korean-like energy environment.

In addition to the installed capacity, a simple comparison of settlement prices of various electricity sources in South Korea is also possible. Figure 7 illustrates the unit price of electricity for different energy sources in South Korea as of 2023. Compared to coal-fired power and renewable energy sources, large-scale nuclear power plants have comparably low settlement prices. Since SMRs have not yet been built in South Korea, it is challenging to evaluate their settlement price. Therefore, the comparison will be based on expected LCOE values. SMRs are anticipated to have higher costs than large nuclear power plants due to the lack of economies of scale. For instance, while the LCOE of large-scale nuclear power plants in South Korea is approximately USD 53.5 per MWh, the target LCOE for the i-SMR, a PWR-type SMR under development in South Korea, is USD 65 per MWh. This indicates that the LCOE for the SMR is expected to be about 1.2 times higher than that of large nuclear power plants. Although the LCOE and unit prices are different concepts, for energy sources like nuclear power—where upfront construction costs dominate the cost—the two values can be similar. Assuming the unit price for SMRs is approximately 1.2 times that of large nuclear power plants, it would still be much more economical compared to renewable energy sources. This demonstrates that nuclear energy not only requires smaller installed capacity when replacing CPPs but also offers the advantage of lower unit electricity prices.

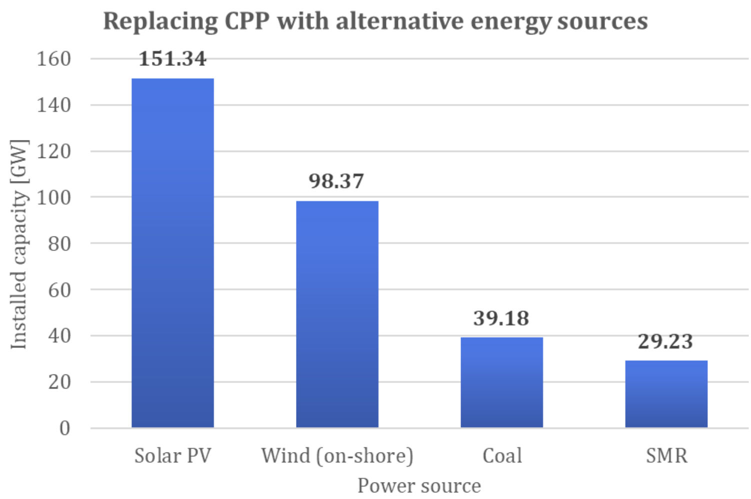


Figure 6. Comparison of installed capacities of solar PV, wind, and SMRs for replacing CPPs. The installed capacity of CPPs is the actual value in 2023.

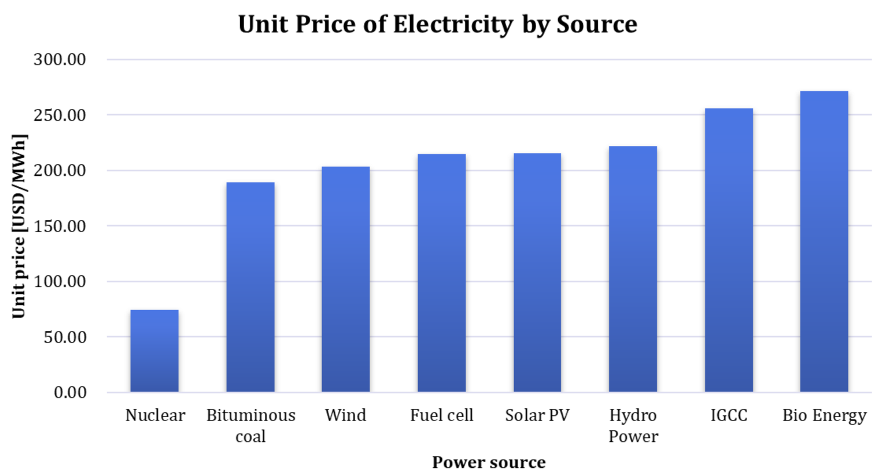


Figure 7. Comparison of unit price of electricity by source in South Korea, 2023 [16].

2.4. Required Capacity of Energy Storage System for VRE

Up to the previous section, the amount of installed capacity required to replace CPPs with VRE was calculated without having an ESS. This brought up an issue of expanding the transmission line substantially in South Korea. However, for VREs, simply installing the calculated amount of installed capacity does not suffice to match the power generation of CPPs due to their inherent variability. If an ESS is connected to VRE, it can operate closer to the current CPP generation profile. In cases of excess production, the VRE can store energy in the ESS, and during times of insufficient generation, it can draw energy from the ESS. This section aims to determine how much ESS is required when replacing CPPs with VREs, as the additional costs of installing ESS can be an important consideration for policymakers and stakeholders.

2.4.1. Data Sources

Before examining the calculation methods and results, the data acquisition method is discussed. In this section, the capacity factor profiles of solar and wind power plants are analyzed to accurately calculate the annual ESS charging/discharging profiles. The time resolution for the capacity factor profiles is set on an hourly basis. This data was obtained from the work by Lei Duan et al. [3]. In their work, a stylized electricity system was modeled under a least-cost optimization framework, considering electricity demand and renewable potential in 42 countries, including South Korea. The study used the Modern-Era Retrospective Analysis for Research and Application, Version-2 (MERRA-2) reanalysis product to model profiles, segmenting the world into 207,936 cells. Wind capacity factors were calculated assuming a turbine hub height of 100 m, with specific cut-in and cut-out wind speeds. Solar PV capacity factors were determined based on location and time, using the zenith angle. For individual countries, the capacity factor was calculated by averaging the top 25% of grid cells within each country.

2.4.2. ESS Modeling

The main objective of this calculation is to minimize the rate of deficiency occurrences, i.e., the situations where the combined generation of VRE + ESS falls short of the CPP output throughout the year. The goal is to determine the minimum ESS capacity that meets the targeted deficiency ratio.

The deficiency ratio is defined as the proportion of time during which deficiencies occur throughout the year. It serves as an indicator of the frequency of energy deficiencies rather than the magnitude of the energy deficiency.

To achieve a targeted deficiency ratio, it involves fitting a charging/discharging profile for the ESS using the previously calculated installed capacity of VRE, its capacity factor profile, and the CPP generation profile. This process must satisfy key constraints such as ESS efficiency, storage limits, and charging/discharging power limits. From the completed charging/discharging profile, the rate of deficiency occurrences can be calculated.

There are various types of ESS, such as the battery energy storage systems (BESS), pumped hydro energy storage (PHES), hydrogen, and compressed air energy storage (CAES). For this study, lithium-ion batteries, which are well-commercialized and have a high round-trip efficiency, were chosen as the ESS. The specifications for the ESS are assumed from the reference [17], which was developed for utility-scale battery applications connected to VRE, matching with the purpose of this research. The specifications are outlined in Table 3.

Table 3. Assumed BESS specifications [17].

Battery Type	Lithium-Iron Phosphate (LiFePO)
Round trip efficiency [%]	82.59
Power limit [kW]	1000
Storage limit [kWh]	2500
Cycling life [cycles]	7300

Based on the BESS specifications, scenarios for replacing South Korea's 2023 coal-fired power generation with solar PV + ESS and wind + ESS were analyzed. To optimize the total capacity of ESS, an objective function must be determined. As stated before, this study aims to reduce the deficiency portion. Various target deficiency portions have been set (0.1, 1, 5, and 10% of the year), and the minimum number of ESS units needed to satisfy each deficiency portion has been searched for. It should be noted that the cost of storage was not considered in the objective function to be minimized. The algorithm to search for the minimum BESS is as follows.

First, the number of ESS units is assumed. Then, the process (processes i–iv) of matching the BESS charging/discharging profile with the VRE generation is carried out. After the processes i–iv are done, the deficiency portion (defined as the number of hourly deficiency occurrences divided by 8760 h) is obtained. If the deficiency portion is higher than the target value, the number of ESS is increased, and the process is repeated until the target value is achieved. Once the minimum number of ESS to meet the deficiency is obtained, the total storage capacity can be estimated (see Table 4). Moreover, the annual electricity generation profile, monthly ESS charging/discharging history, and the distribution of deficiency occurrence can be obtained (Figures 8–11).

Table 4. Optimal number of ESS, total storage, and power capacity according to the target deficiency portion. Replacement with solar PV and wind energy has been analyzed separately.

Target Deficiency Portion [%]	Replacement with Solar PV			Replacement with Wind		
	Number of ESS	Total Storage Capacity [TWh]	Total Power Capacity [TW]	Number of ESS	Total Storage Capacity [TWh]	Total Power Capacity [TW]
0.1	8,833,225	22.08	8.83	13,500,450	33.75	13.50
1	8,155,165	20.39	8.15	12,928,235	32.32	12.93
5	5,227,295	13.07	5.23	11,119,575	27.80	11.12
10	2,815,060	7.04	2.82	8,735,465	21.84	8.74

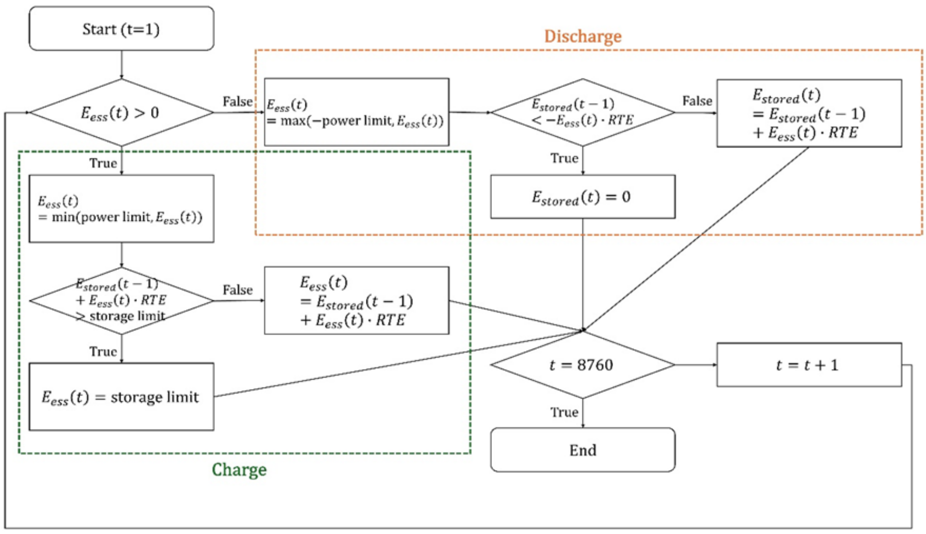


Figure 8. Calculation process of ESS charging and discharging history.

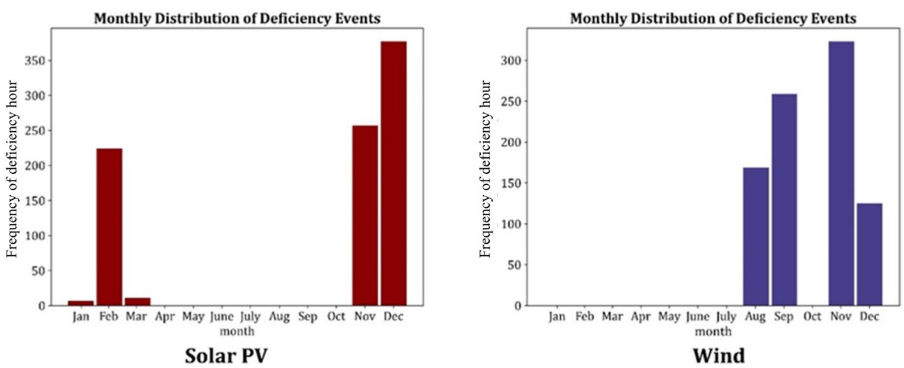
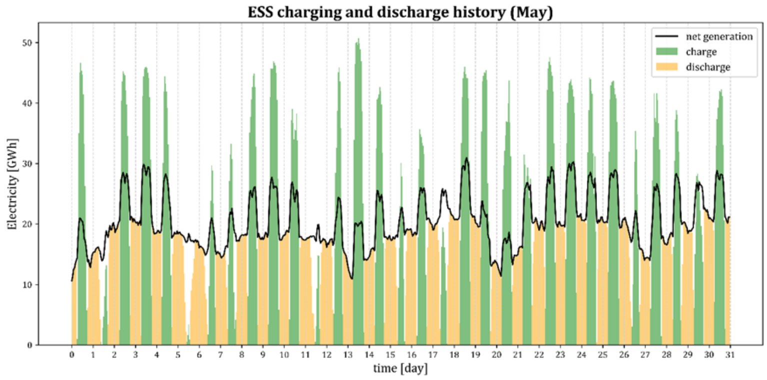


Figure 9. Monthly distribution of deficiency events when deficiency portion is 10%.



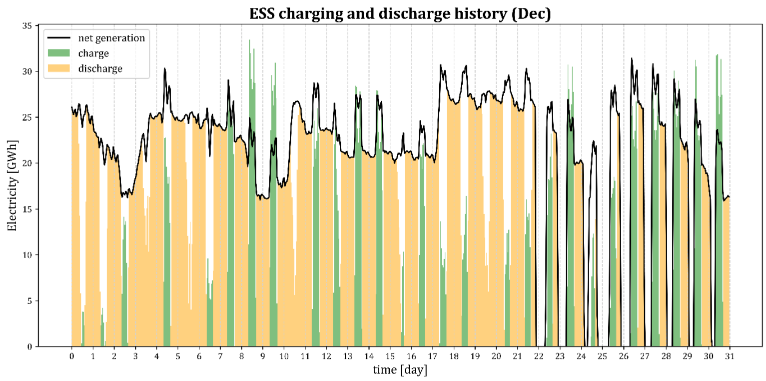
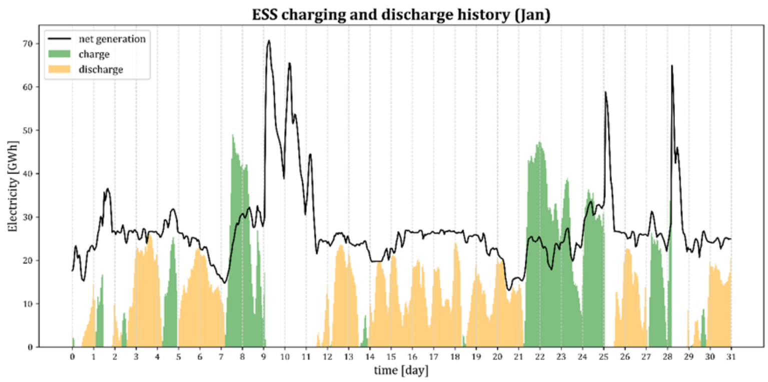


Figure 10. ESS charging and discharge history on May (**top**) and December (**bottom**) when replacing CPPs with solar PV.



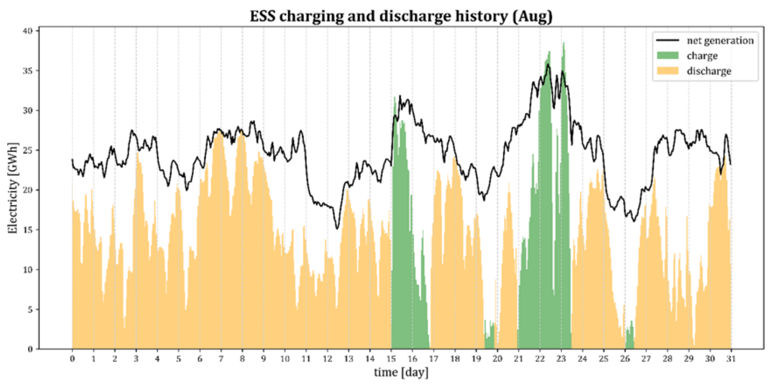


Figure 11. ESS charging and discharge history on January (**top**) and August (**bottom**) when replacing CPPs with wind energy.

i. Define the hourly demand (E_{demand}) as the hourly electricity production from CPPs (E_{CPP}) in 2023 (Equation (4)).
ii. Obtain the electricity production from VRE ($E_{VRE}(t)$) by multiplying the hourly capacity factor (cf_{VRE}(t)) to the installed capacity (IC_{VRE}) that was calculated in Section 2.3. (Equation (5)).
iii. Define the energy to be charged/discharged as the difference between the hourly demand and the electricity production from VRE (Equation (6)).

$$E_{demand}(t) = E_{CPP}(t) \tag{4}$$

$$E_{VRE}(t) = IC_{VRE} \times cf_{VRE}(t) \tag{5}$$

$$E_{ess}(t) = E_{VRE}(t) - E_{demand}(t) \tag{6}$$

iv. For t = 0 to t = 8760 h, iterate the process depicted in the diagram of Figure 8. If E_{ess} (t) at time t is positive, it means that the VRE is producing excess energy compared to the demand. Thus, $E_{ess}(t)$ shall be charged to the ESS considering the charging efficiency. However, there are several conditions to be considered during the charging, such as the maximum power limit or the storage capacity limit. For instance, if the storage is full but the VRE is producing excess energy, the situation is defined as "surplus".

When $E_{ess}(t)$ at time t is negative, it means that the grid is requiring more electricity than the electricity produced from VRE; thus, energy shall be discharged from the ESS and vice versa. Several conditions shall be considered, such as the energy available for discharge and the maximum power limit. If the amount of energy to be discharged is larger than the amount of energy currently stored in the ESS (E_{stored}), it means that the demand cannot be matched; thus, it is defined as "deficiency". The history of deficiency occurrence is tracked for the whole iteration process.

2.4.3. ESS Modeling Results

From Table 4, it is observed that both solar PV and wind energy require a great number of ESS units as the deficiency portion decreases. The wind energy generally requires a greater amount of ESS compared to solar PV due to the greater variability and randomness of the wind generation profile.

Solar PV and wind energy require storage capacities of up to 22.08 and 33.75 TWh, respectively. This means that replacing CPPs with VRE + ESS would require a tremendous amount of ESS capacity. As of 2023, the size of the BESS market in Korea is about 185 GWh, and it is projected to grow to about 618 GWh by 2035 [18]. This projected scale is still significantly smaller compared to the required ESS capacity calculated in this study. To meet the supply of CPPs with VRE, the ESS market would need to grow at least 182 times beyond its 2023 level.

Figure 9 displays a histogram showing the monthly distribution of deficiency events when the target deficiency portion is set as 10%. The left side represents the case of replacing with solar PV and the right side with wind. For solar PV, it was observed that most deficiencies occur during the months with less sunlight (November to December and January to March), particularly with a high frequency in December. Conversely, for wind, most deficiencies occurred between August and December. While wind power generation generally decreases in summer and increases in winter, its strong variability can lead to a lack of clear seasonality.

Furthermore, it was confirmed that deficiencies for both solar PV and wind energy are concentrated in December. The reasons for this can be found not only in seasonal/climatic factors but also from the perspective of the amount of charge in the ESS. At the start of the year, i.e., t = 1, it is assumed that all ESS are fully charged. However, as the days progress, the amount of stored energy in the ESS gradually decreases, leading to frequent deficiencies. Various factors may contribute to this, such as the efficiency of charging/discharging and the significant variability of VRE. In summary, the analysis results infer that even when combining VRE with ESS, deficiencies may be concentrated during certain periods due to the seasonal/climatic factors of the South Korean environment and the limitations of ESS capacity.

Next, the monthly ESS charging and discharging history, as well as the combined generation of VRE + ESS (net generation, E_{net}), are examined. E_{net} refers to the value obtained by subtracting the ESS charging amount (E_{charge}) and adding the discharging amount ($E_{discharge}$) to the electrical production of VRE. To compare the seasonal charging/discharging history, the history of solar PV is plotted for May and December (Figure 10), while wind energy is plotted for January and August (Figure 11). The target deficiency portion is fixed at 1%.

$$E_{net}(t) = E_{VRE}(t) - E_{charge}(t) + E_{discharge}(t) \quad (7)$$

For solar PV, in May, there was sufficient sunlight resulting in a pattern of consistent charging and discharging, and it was observed that net generation remained close to baseload operation. However, in December, there was insufficient sunlight leading to more discharging than charging, and toward the end of December, a phenomenon of ESS storage depletion causing net generation to drop to 0 was observed.

Figure 11 depicts the charging/discharging history in January and August when CPPs are replaced with wind. While wind power generation is abundant from January to March, it tends to be insufficient during the summer. Examining the period from the 9th to the 12th of January in the history, there are even instances where wind power generation exceeds the ESS storage capacity. Conversely, in December, it appears that electricity was mainly supplied by discharging the energy stored in the ESS throughout most time periods. Furthermore, the charging/discharging patterns exhibit irregular and random tendencies compared to solar PV. It can be inferred that due to these tendencies, a larger amount of ESS capacity is required for wind compared to solar PV.

Lastly, Figure 12 shows the annual net generation along with the existing coal-fired power generation, i.e., demand, for each target deficiency portion. The left side represents the scenario where solar PV + ESS is substituted, while the right side represents the scenario where wind + ESS is substituted. For solar PV + ESS, it appears to closely follow the coal-fired power generation (depicted as the orange plot labeled "as demand") relatively well. However, as the deficiency portion increases, points of generation inadequacy become more pronounced during the winter season. On the other hand, for wind + ESS, there were frequent occurrences where the net generation profile deviated from the demand. Particularly, there were frequent cases of excess production occurring between January and April, which may lead to curtailment of the wind-generated power.

In conclusion, Table 5 shows the specifications for each optimal VRE system. The optimal system refers to the VRE + ESS system that satisfies a deficiency portion of 0.1%. The specifications include the installed capacity of the VRE, battery charging and discharging capacity, annual energy generation, curtailment, and the capacity factor of the storage. The capacity factor of storage was particularly low, as the amount of discharged energy was small compared to the total capacity of the ESS. During periods when the VRE generation is low compared to the energy demand, the ESS capacity inevitably increases to meet the demand during those times. In future research, it is necessary to explore energy management methods or hybrid systems that can meet the energy demand with realistic ESS capacity during low-generation periods.

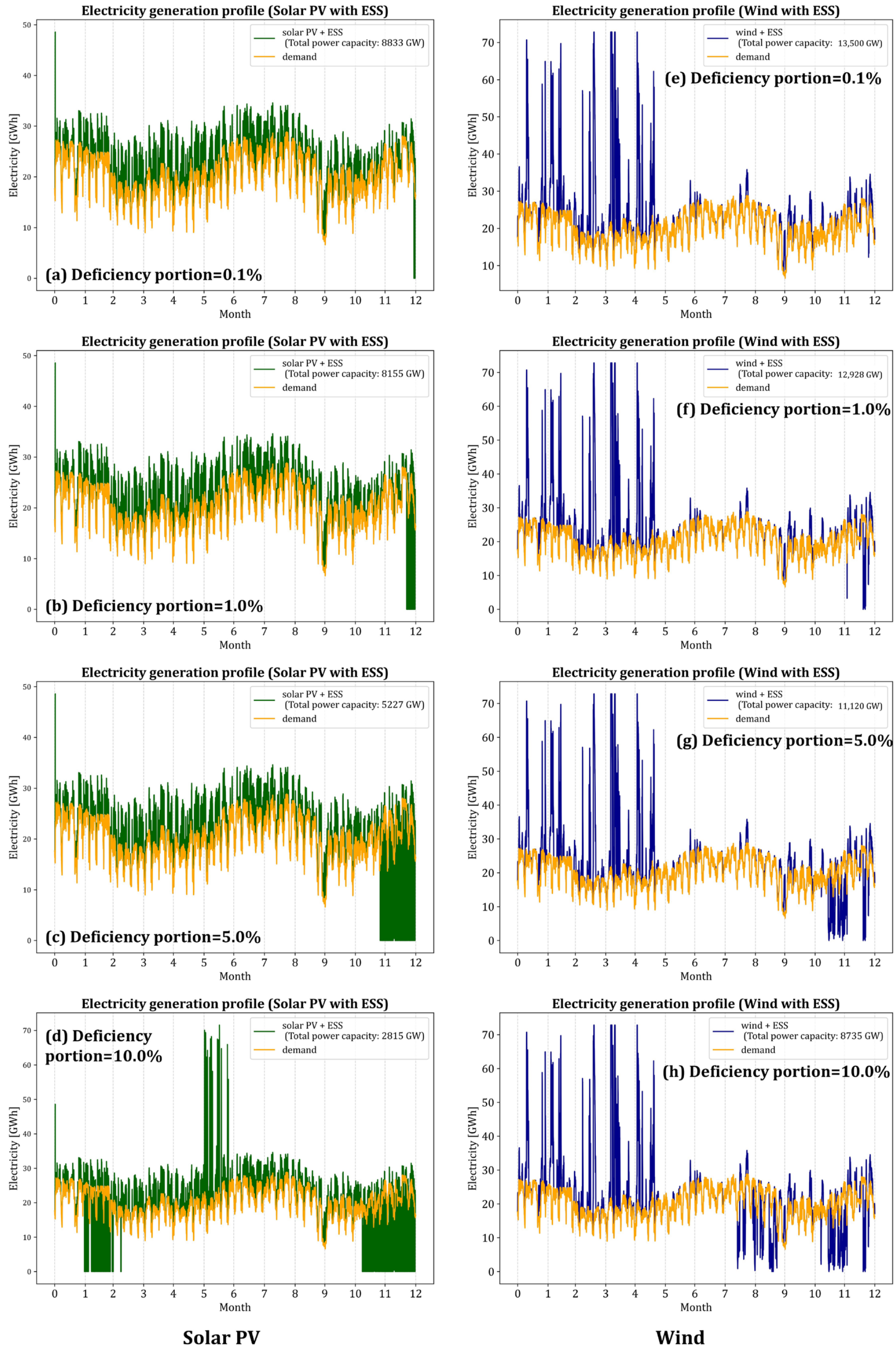


Figure 12. Comparison between electricity generation profile of VRE + ESS and the electricity demand.

Table 5. Summary of the optimal VRE + ESS system specification.

	Solar PV + ESS	Wind + ESS
Installed capacity of VRE [GW]	151.34	98.37
Battery charging and discharging capacity [TW]	8.83	13.50
Annual generation [TWh]	194.32	204.08
Curtailment [TWh]	17.22	26.89
Capacity factor of storage [%]	0.13	0.06

3. CPPs for Repowering in South Korea

3.1. Reference CPPs for Repowering

In identifying target CPPs to be repowered in South Korea, various factors, including planned retirement day of CPPs and their electricity generation capacity, should be considered. To efficiently repower thermal power plants with various operating conditions and layouts based on their capacity, it is essential to first select the type of CPP to be repowered. In order to maximize the carbon emission decrement from such repowering, it is more efficient to replace aging CPPs with newer ones that emit relatively less carbon [19]. Therefore, in this study, thermal power plants in South Korea are classified based on their planned retirement day, and the reference plant is selected by observing the potential of being replaced with SMRs.

This research utilized publicly accessible data from the Korea Electricity Exchange [20], Electric Power Statistics Information System [21], and Repowerscore [22]. Ninety-one thermal and combined heat and power (CHP) plants with capacities of 30 MWe or greater located on the mainland of South Korea are examined. The analysis assessed the number and capacities of these plants on an individual unit basis.

Figure 13 shows the distribution of retirement dates for the 77 thermal plants scheduled to retire after 2023. The majority of thermal power plants scheduled for retirement beyond 2040 began operation in the 2010s or later. Including these plants does not align with the purpose of repowering, which reduces carbon emissions from replacing aging thermal plants. Therefore, the focus was shifted to the 40 plants retiring before 2040, and these were redistributed based on the operating capacity.

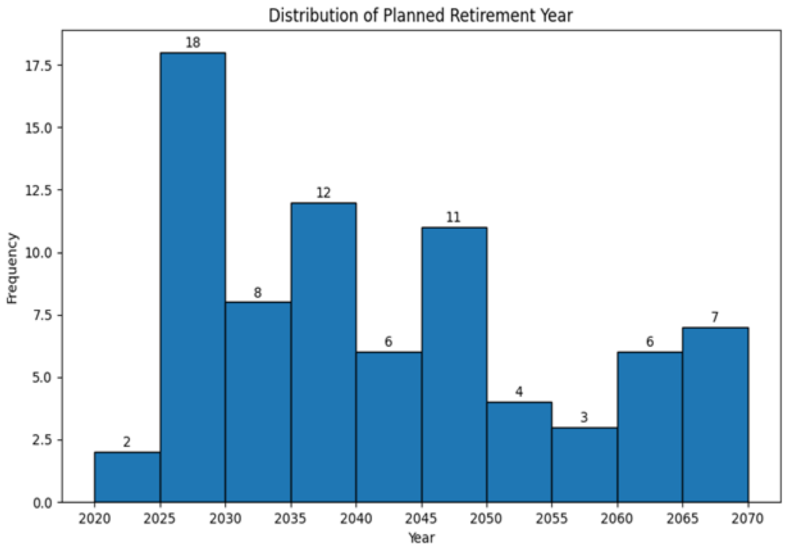


Figure 13. Distribution of planned retirement day.

As shown in Figure 14, the largest number of these plants falls within the 500 MW class, with 30 units. This suggests there is a significant demand for decarbonization and repowering for 500 MW coal power plants, which will be the prime candidate in this study.

3.2. Steam Cycle Characteristics of 500 MW CPP

Since there is a potential to repower CPPs while reusing the steam turbine and its associated equipment by switching the fuel to provide the heat, the steam cycle information of the selected reference 500 MW CPP is summarized. This information will be utilized in the following section to discuss the issue of using SMRs to replace the coal boiler while utilizing the steam turbine of the existing CPP.

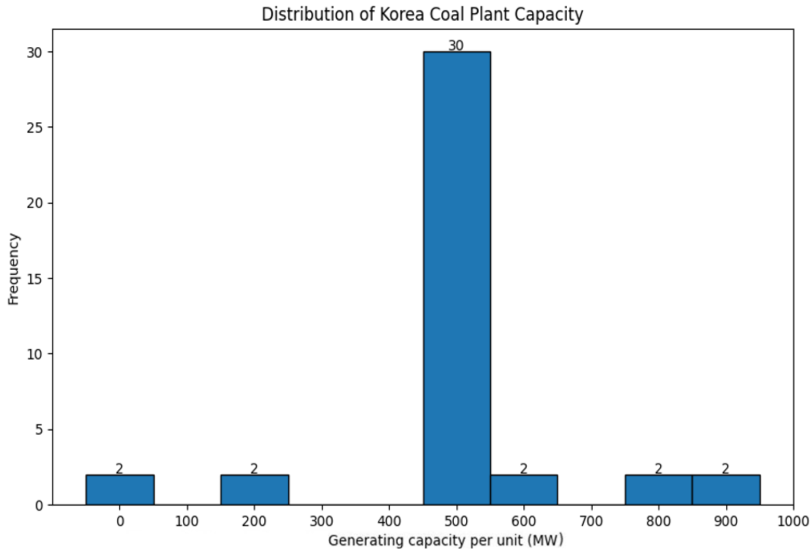


Figure 14. Distribution of operation capacity retired until 2040s.

Figure 15 illustrates a T-S diagram depicting the conditions from the inlet of the HP turbine to the outlet of the LP turbine in the reference 500 MW thermal power plant [23]. The exact temperature and pressure at each point are detailed in Table 6. As shown in Figure 15, the inlet of the HP turbine is in a supercritical region with high pressure and temperature. The inlet condition of the IP turbine maintains the same temperature as the HP turbine inlet but has a significantly lower pressure, approximately 3.601 MPa. Lastly, the inlet condition of the LP turbine has the lowest temperature and pressure among the three turbines, with 0.841 MPa and 334.80 degrees Celsius.

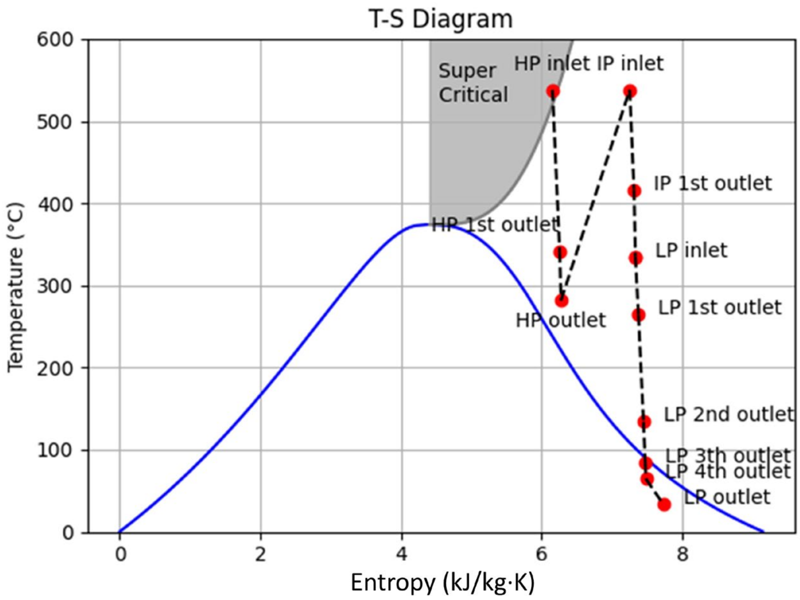


Figure 15. T-S diagram of 500 MW thermal power plant.

Table 6. Operation condition of 500 MW CPP [23].

Location	Pressure (MPa)	Temperature (°C)
HP Inlet	24.233	537.80
HP 1st Stage Outlet	6.314	341.06

Table 6. *Cont.*

Location	Pressure (MPa)	Temperature (°C)
HP Outlet	3.958	281.66
IP Inlet	3.601	537.80
IP 1st Stage Outlet	1.528	416.67
IP Outlet	0.841	334.80
LP Inlet	0.841	334.80
LP 1st Stage Outlet	4.50×10^{-1}	264.07
LP 2nd Stage Outlet	1.20×10^{-1}	133.88
LP 3rd Stage Outlet	5.64×10^{-2}	84.40
LP 4th Stage Outlet	2.46×10^{-2}	64.62
LP Outlet	5.40×10^{-3}	33.18

4. Using SMRs for Coal Repowering

4.1. Options of Coal Repowering

This study compared three options to determine how to convert selected thermal power plants to nuclear power generation with SMRs. A summary of the proposed coal repowering options is shown in Table 7. These options were part of a comprehensive analysis that examined the feasibility and implications of converting aging CPPs to SMR power plants in the United States. The study explored the feasibility of such conversions, the economic and technical factors influencing investor decisions, and the impacts on local communities [24]. In the report, overnight construction costs (OCC) were estimated by leveraging data from the Advanced Fuel Cycle Cost Basis [25]. This report provides a detailed methodology for calculating OCC for various nuclear fuel cycle options. The analysis incorporates data from the EEDB Program (1979) to identify shared components between CPPs and nuclear power plants (NPPs) [26]. By evaluating the reuse potential of components such as power transmission infrastructure, cooling systems, and civil structures, the study estimated the cost savings achievable through repurposing existing CPP infrastructure. The resulting OCC values reflect Nth-of-a-kind (NOAK) conditions and exclude financing costs, offering a baseline for understanding the potential economic benefits of repowering projects. Thus, it should be noted that the OCC values may represent underestimated figures compared to real cases.

Table 7. Typical Coal Repowering Option from [24].

Options	Site	Electrical Components	Heat Sink Components	Steam-Cycle Components	Total Overnight Capital Cost of PWR ($/kW)	Total Overnight Capital Cost of HTGR ($/kW)
#1	Not reused	Not reused	Not reused	Not reused	4572	5859
#2	reused	reused	reused	Not reused	3598	-
#3	reused	reused	reused	reused	-	3951

For example, the construction cost of NuScale, a PWR-type SMR in the United States, was initially estimated at $5.3 billion but surged to $9.3 billion by 2023 [27]. This increase was attributed to factors such as high interest rates and rising raw material costs. This demonstrates that first-of-a-kind SMRs with financial costs integrated can have significantly higher OCC values than those summarized in Table 7. However, the purpose of presenting this table in our study is not to assert that repowering is economically feasible. Instead, it aims to explore various infrastructural options for repowering, assess the extent to which infrastructure can be reused, and provide an approximation of the associated cost savings.

Option 1 involves building a new nuclear power plant without any relation to the existing CPP. This approach offers a clean slate, allowing for modern design implementation without constraints from existing infrastructure. However, it fails to capitalize on potential cost savings and faces the full burden of CPP decommissioning costs.

Option 2 proposes reusing the site, electrical, and heat-sink components from the CPPs for the new nuclear power plant. This strategy leverages existing infrastructure, potentially reducing construction costs and timelines. It also maintains continuity in terms of location and some workforce. However, it still incurs significant CPP decommissioning costs and limits the design flexibility of the new nuclear power plant.

Option 3 goes beyond the others by reusing not only the site, electrical, and heat sink components but also the steam cycle components of the CPP. This is a very useful way to maximize the utilization of existing infrastructure and potentially achieve more effective carbon savings. The cost savings from such extensive reuse is not only economically sound but also environmentally attractive in that it reduces waste and makes the best use of available resources. As shown in Table 7, Option 3 is more economical than Option 1 for HTGR-type reactors. For PWR-type reactors, the estimated price for Option 3 is not available due to the lack of projects using this option [24].

However, this study proposes an initial repowering method based on Option 3 for both PWR and HTGR reactors. This is to further explore the possibility of using PWR-based SMRs for repowering coal and identify the technical issues for this option. The characteristics of both PWR and HTGR-based SMRs and the specific features of the target thermal power plant will be next considered for evaluating Option 3 for repowering coal with SMRs.

4.2. Evaluation Methodology

When considering the replacement of a CPP with an SMR based on Option 3, it is crucial to maintain the volumetric flow rate to ensure compatibility with the existing steam turbine system. This approach not only leverages the established infrastructure but also minimizes the need for extensive modifications, which can be both cost-effective and time-efficient for SMRs.

To efficiently reuse the currently operating thermal power plant equipment during the process of replacing the heat source of CPPs with SMRs, an integration is proposed, beginning from the inlets of the three turbines mentioned above. The work, mass, and volumetric flows for the three candidate turbines are detailed in Table 8. To maximize the work produced by conventional turbines, this study focuses on initial research on integration starting from the IP turbine inlet, excluding steam in supercritical regions that are not realistically achievable by SMRs, as in the inlet conditions of HP turbines of CPP.

Table 8. Steam condition of merge point candidates.

	Temperature (°C)	Pressure (MPa)	Mass Flow Rate (kg/s)	Density (kg/m^3)	Volume Flow Rate (m^3/s)	Work (MW)
HP inlet	537.8	24.23	420.21	77.83	5.40	164.30
IP inlet	537.8	3.60	338.02	9.84	34.33	135.43
LP inlet	334.8	0.84	295.40	3.05	96.89	200.27

In this paper, the published conditions of currently accessible HTGR and PWR-type SMRs were used as examples to determine the number of SMR units required when repowering the selected reference CPP while utilizing the existing steam turbine. The steam conditions at the exit of the steam generator were utilized for the analysis. The list of investigated SMRs contains two HTGR references and two PWR references. The steam generator conditions were determined as follows since the publicly available information does not provide all the necessary information for the analysis.

For HTGRs, only the core information is publicly available. This core data was used to calculate the conditions for the steam that could be generated by the steam generator. To simplify the analysis, it was assumed that the product of the flow rate inside the core and the enthalpy change at the inlet and outlet is equal to the product of the flow rate and enthalpy change at the secondary side of the steam generator. To determine the enthalpy at the inlet of the steam generator, a conservative assumption was made that the quality at that point is 0 and the pinch temperature inside the steam generator is assumed to be 15 K. The pressure at the inlet and outlet of the steam generator is determined by the pressure corresponding to the saturation temperature at the specified pinch temperature.

Additionally, the conditions at the outlet of the steam generator were considered to be the same as the conditions at the coupling with the thermal power plant. This approach enabled the determination of the mass flow rate on the steam generator side (Equation (9)).

$$\dot{m}_{core}\left(H_{core_{out}} - H_{core_{in}}\right) = \dot{m}_{2nd}\left(H_{SG_{out}} - H_{SG_{in}}\right) \tag{8}$$

$$\frac{\dot{\mathrm{m}}_{core}\left(H_{core_{out}} - H_{core_{in}}\right)}{H_{SG_{out}} - H_{SG_{in}}\left(T_{pinch}, Q = 0\right)} = \dot{\mathrm{m}}_{\mathrm{SG}} \tag{9}$$

$$\dot{\mathrm{m}}_{core} : \ Mass\ flow\ rate\ of\ core \quad \dot{\mathrm{m}}_{2nd} : \ Mass\ flow\ rate\ of\ steam\ generator\ secondary\ side$$

$$H_{core_{in}} : \ Enthalpy\ of\ core\ inlet \quad H_{core_{out}} : \ Enthalpy\ of\ core\ outlet$$

$$H_{SG_{in}} : \ Enthalpy\ of\ steam\ generator\ inlet \quad H_{SG_{out}} : \ Enthalpy\ of\ steam\ generator\ inlet$$

After determining the mass flow rate using the aforementioned method, it is then throttled to achieve a pressure condition suitable for coupling with the secondary side of the thermal power plant. In this process, the inlet conditions of the intermediate pressure (IP) turbine of the thermal power plant are utilized. This is because the reference power plant utilizes steam from the supercritical region in the high-pressure (HP) turbine. The high pressure and high temperature impose a significant load on the steam generator. Therefore, to facilitate the integration of SMRs and thermal power plants, it is preferable to avoid operating conditions in the supercritical region as much as possible. With the inlet pressure condition of the IP turbine met through throttling, the density at that specific pressure and temperature determines the volumetric flow rate per unit of the SMR. This process was utilized to calculate the number of SMR units required to produce steam equal to the volumetric flow rate of the IP turbine of the thermal power plant.

Since SMRs of the PWR type cannot reach the inlet temperature of a conventional thermal power plant in most cases, additional thermal energy is assumed to be utilized to arrive to the target temperature. As illustrated in Figure 16, steam is heated by an external fuel and then throttled to enter the IP turbine. In this process, the steam condition prior to heating begins at the steam generator condition of each SMR and is heated to a temperature region with the same enthalpy as the inlet condition of the IP turbine before being throttled. During this process, the number of SMR units and the amount of external heat sources required to match the volumetric flow rate of a conventional IP turbine will be evaluated.

4.3. Evaluation Results

HTGR uses helium as a coolant, and its specific operating conditions of HTGR reference #1 are detailed in Table 9 [28]. A temperature profile that satisfies the previously mentioned conservative pinch temperature of 15 K under these conditions is shown in Figure 17. A pinch has formed between the core inlet (steam generator primary side outlet) and the steam generator secondary side inlet. This profile results from maximizing the flow on the secondary side while maintaining a pinch temperature of 15 K for all temperatures between the inlet and outlet of the steam generator's primary side. Under these conditions, the mass flow rate of the steam generator's secondary side is 53.56 kg/s.

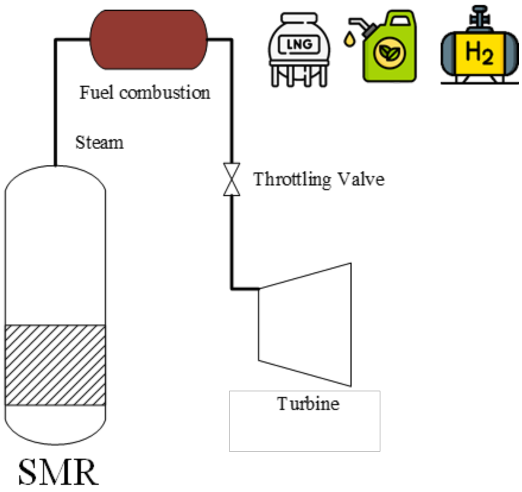


Figure 16. Conceptual layout of PWR SMR—CPP integration.

Table 9. Core condition of HTGR reference #1 [28].

Core Inlet T (°C)	Core Outlet T (°C)	Pressure (MPa)	Mass Flow Rate (kg/s)
300	630	6	71.1

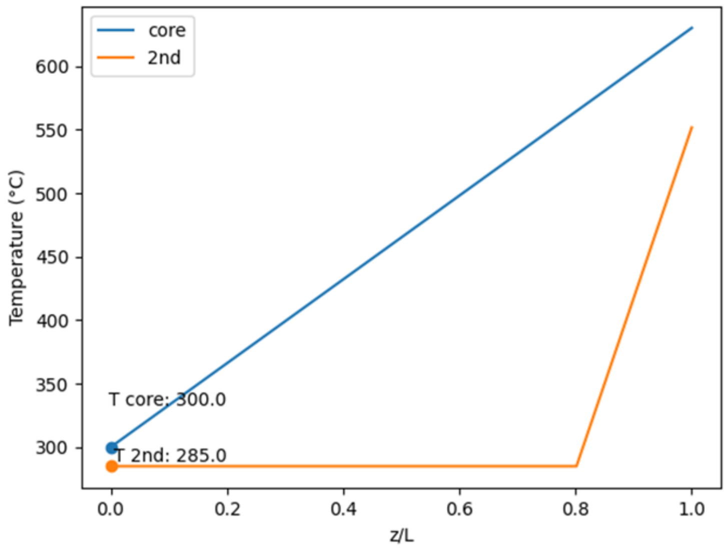


Figure 17. Temperature profile of HTGR reference #1 core and steam generator.

Since the steam outlet has the same enthalpy as the IP turbine inlet condition of the reference thermal power plant, throttling will adjust the steam to match the target condition. This process is illustrated in Figure 18, and the conditions at each point are detailed in Table 9. Considering the density of the steam at the IP turbine inlet condition after throttling, a single unit of HTGR reference #1 can produce a volumetric flow rate of 5.44 m^3/s. Therefore, approximately 6.30 units would be required to match the volumetric flow rate at the IP turbine inlet, as indicated in Table 10.

The same analysis was conducted on HTGR reference #2. The core operating conditions for HTGR reference #2 are provided in Table 11 [29]. Compared to HTGR reference #1, HTGR reference #2 shows a lower core inlet temperature, a higher core outlet temperature, and the same mass flow rate. In the case of the HTGR reference #2, the temperature profile of the primary and secondary steam generators was calculated with the condition of maximizing the mass flow rate of the steam generator. A 15K pinch was formed at the outlet of the steam generator primary and the inlet of the secondary, similar to the HTGR reference #1 case.

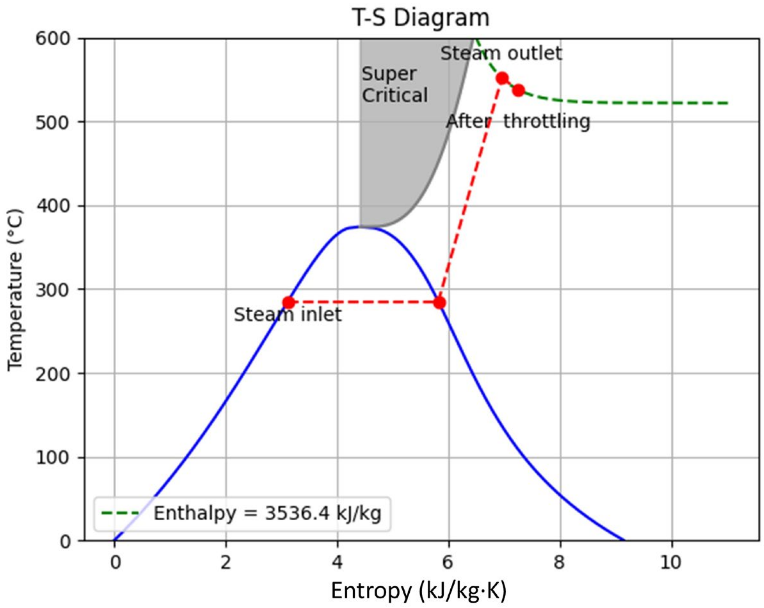


Figure 18. T-S diagram of HTGR reference #1-thermal power plant merge.

Table 10. Steam condition of HTGR reference #1-thermal power plant merge.

	Steam Inlet	Steam Outlet	After Throttling
Temperature (°C)	285	551.63	537.80
Pressure (MPa)	6.91	6.91	3.601
Entropy (kJ/kg-K)	3.11	6.96	7.25

Table 11. Core condition of HTGR reference #2 [29].

Core Inlet T (°C)	Core Outlet T (°C)	Pressure (MPa)	Mass Flow Rate (kg/s)
260	750	6	71.1

As shown in Figure 19, the temperature at the inlet of the steam generator secondary is 245 °C, which is 15 K lower than the core inlet temperature of 260 °C. For HTGR reference #2, the larger temperature difference between the inlet and outlet of the core compared to HTGR reference #1 allows it to generate a higher mass flow rate of 55.17 kg/s. However, despite the relatively large temperature change, the mass flow rate did not increase significantly because helium, the coolant in the core, exists in the gas phase in this temperature range. The increased enthalpy from the higher temperature range is small compared to the latent heat of steam. The effect is minimal.

Figure 20 illustrates the T-S diagram for steam from the secondary steam generator inlet to throttling for merging with the IP turbine. The conditions at each point are detailed in Table 12. Since the secondary inlet temperature is lower compared to the HTGR reference #1 case, the corresponding pressure in the secondary is also relatively low. After calculating the steam density post-throttling and using the previously obtained mass flow rate, the volumetric flow rate generated per HTGR reference #2 unit is 5.60 m^3/s. Therefore, approximately 6.12 units are required to meet the IP turbine's inlet conditions.

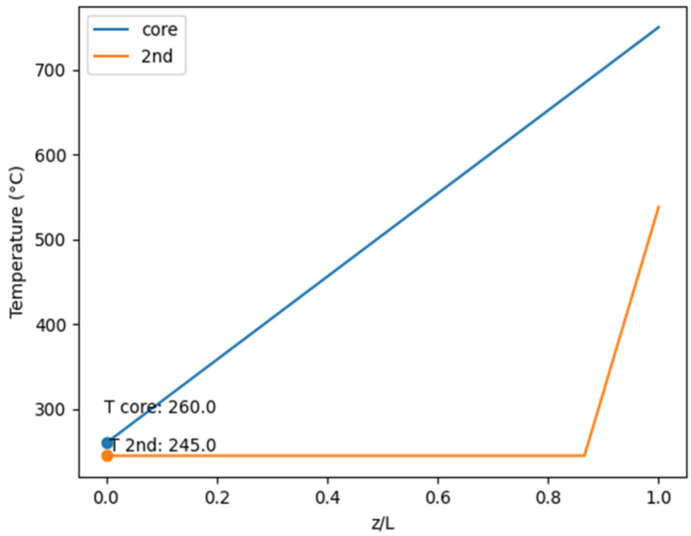


Figure 19. Temperature profile of HTGR reference #2 core and steam generator.

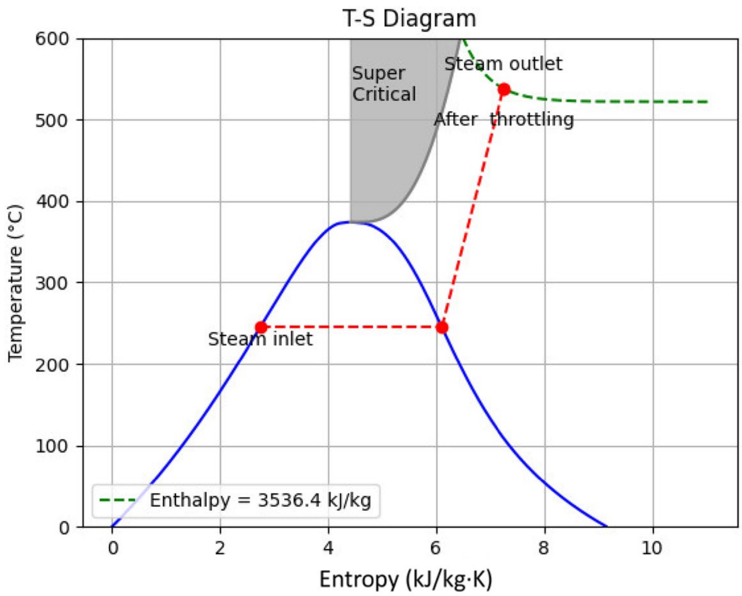


Figure 20. T-S diagram of HTGR reference #2 thermal power plant merge.

Table 12. Steam condition of HTGR reference #2-thermal power plant merge.

	Steam Inlet	Steam Outlet	After Throttling
Temperature (°C)	245.0	538.01	537.8
P (MPa)	3.650	3.650	3.601
S (kJ/kg-K)	2.75	7.24	7.25

In case of PWR reference #1, it is capable of producing steam that meets the outlet conditions specified in Table 13. The challenge with integrating a PWR-type SMR with the power conversion system of a thermal power plant is arriving at the required high temperatures. Therefore, the steam inlet conditions are achieved by using other energy source to make the steam enthalpy as the same value of the operating IP turbine inlet. This process is depicted in Figure 21, with the conditions at each point detailed in Table 13. Using this process, a single unit, which has 160.8 kg/s [30] of mass flow rate, can supply 16.33 m^3/s of steam. To match the operating conditions of a conventional thermal power plant, 2.10 units are required. Additionally, an external heat source providing 101.54 MW per unit is necessary to heat the steam from the steam generator outlet to the inlet conditions of the IP turbine.

Table 13. Steam condition of PWR reference #1-thermal power plant merge.

	Steam Outlet [30]	After Combustion	After Throttling
Temperature (°C)	296	544.58	537.8
Pressure (MPa)	5.2	5.2	3.601
Entropy (kJ/kg-K)	6.16	6.16	7.25

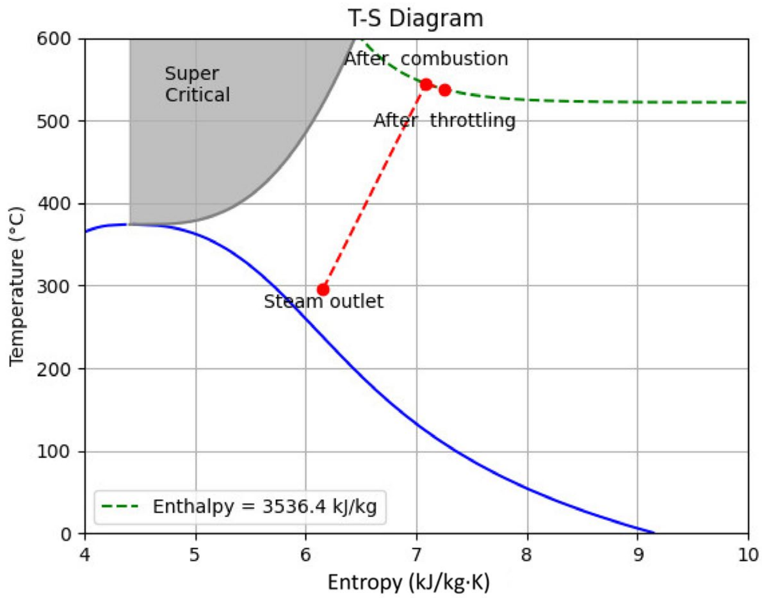


Figure 21. T-S diagram of PWR reference #1-thermal power plant merge.

PWR reference #2 has a relatively high steam generator outlet temperature and pressure compared to PWR reference #1, as shown in Table 14. The same process ensures the steam meets the inlet conditions of the IP turbine, as illustrated in Figure 22. With the mass flow rate of 70 kg/s per unit [31], PWR reference #2 can deliver volumetric flow rate of 7.19 m^3/s. Therefore, 4.77 units are required to meet the IP turbine's inlet conditions. Additionally, PWR reference #2 requires an external heat source of 54.13 MW per unit to achieve this.

Table 15 presents a summary of thermodynamic analysis for different reactor types in the context of repowering CPPs while reusing the part of operating steam turbines. The table compares HTGRs and PWRs, focusing on their volumetric flow rates, required units, and external thermal power needs.

Table 14. Steam condition of PWR reference #2-thermal power plant merge.

	Steam Outlet [31]	After Combustion	After Throttling
Temperature (°C)	321	564.95	537.8
Pressure (MPa)	10.3	10.3	3.601
Entropy (kJ/kg-K)	5.68	6.78	7.25

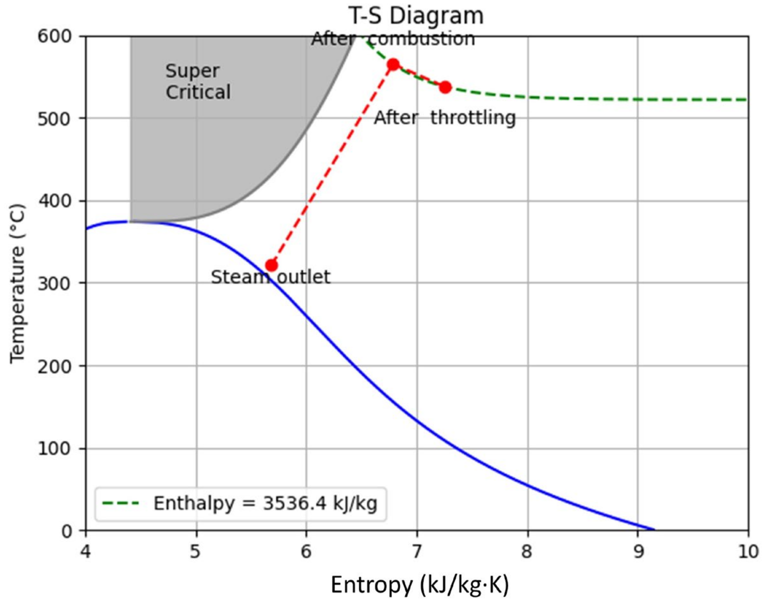


Figure 22. T-S diagram of PWR reference #2-thermal power plant merge.

Table 15. Summary of thermodynamic analysis.

Reactor	Volumetric Flow Rate (m^3/s)	Required Volume Flow Rate (m^3/s)	Required Units of SMR	External Thermal Power (MW)
HTGR reference #1	5.44	34.33	6.30	-
HTGR reference #2	5.60		6.12	-
PWR reference #1	16.33		2.10	185.10
PWR reference #2	7.19		4.77	258.45

HTGRs, represented by references #1 and #2, show volumetric flow rates of 5.44 m^3/s and 5.60 m^3/s, respectively. To meet the required volume flow rate of 34.33 m^3/s, multiple HTGR units are necessary, specifically 6.30 units of reference #1 or 6.12 units of reference #2. The key advantage of HTGRs lies in their high-temperature output, eliminating the need for additional external thermal power in repowering applications. This makes HTGRs thermally efficient, despite the requirement for multiple units.

In contrast, PWRs exhibit different characteristics. PWR reference #1 has a higher volumetric flow rate of 16.33 m^3/s, while reference #2 flows at 7.19 m^3/s. These higher rates mean fewer reactor units are needed to achieve the 34.33 m^3/s target—only 2.10 units for reference #1 or 4.77 units for reference #2. However, PWRs operate at lower temperatures than HTGRs, necessitating additional external thermal power. This is evidenced by the external thermal power requirements: 185.10 MW for reference #1 and 258.45 MW for reference #2. Fewer required number of units and the required external thermal energy are crucial when considering PWRs for repowering CPPs while reusing steam turbines.

The analysis aims to maintain the inlet conditions (temperature, pressure, and volume flow) of the IP turbine, thereby preserving its efficiency. This approach ensures seamless integration of the repowered system with existing turbine infrastructure, minimizing modifications and maintaining operational efficiency. The required volumetric flow rate of 34.33 m^3/s serves as a benchmark for comparing reactor options and determining the number of units needed for each type.

The varying mass flow rates between reactor types highlight the need for careful consideration of optimal extrapolation and branching flows. Further analysis is required to determine the most effective distribution and management of steam flow throughout the system, especially when dealing with multiple reactor units or incorporating external thermal power sources. This optimization is critical for maximizing overall system efficiency and ensuring smooth integration with existing turbine systems in repowering CPPs.

5. Regulatory Issues for Repowering CPPs with SMRs

5.1. Nuclear Safety Regulation System of South Korea

Due to the risk of severe accidents in nuclear power plants, a strict regulatory framework governs the entire life cycle of nuclear plant operations, including licensing, construction, operation, and decommissioning. In South Korea, nuclear safety regulations are managed by two major regulatory bodies: Nuclear Safety and Security Commission (NSSC) and Korea Institute of Nuclear Safety (KINS) (Figure 23).

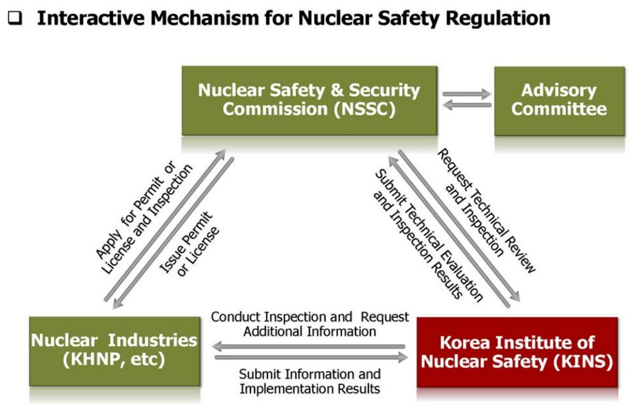


Figure 23. Relationship between nuclear regulatory bodies in South Korea [32].

NSSC is a vice minister-level central administrative agency established to manage South Korea's nuclear safety regulatory system. NSSC oversees all tasks related to nuclear safety regulations, including the licensing and permitting of nuclear industries. Its responsibilities include regulating and inspecting nuclear reactor facilities and radioactive materials and managing nuclear security in the event of domestic or international nuclear accidents. KINS operates under NSSC as a governmental administrative agency providing technical advisory support. Since NSSC does not directly perform supervisory duties, KINS is responsible for supervising nuclear industries and conducting technical regulatory work. NSSC's role focuses on gathering input from affiliated organizations responsible for nuclear safety and communicating it to policymakers and the public, while KINS handles the technical aspects of regulatory enforcement.

South Korea's nuclear legislation structure consists of multiple layers of acts established by NSSC and technical guidelines developed by KINS (Figure 24). Foundational acts, such as the Nuclear Safety Act and the Act on Physical Protection and Radiological Emergency, form the basis of the legal framework. The regulatory requirements set out by these acts are further defined by technical standards established by NSSC and regulatory guidelines developed by KINS.

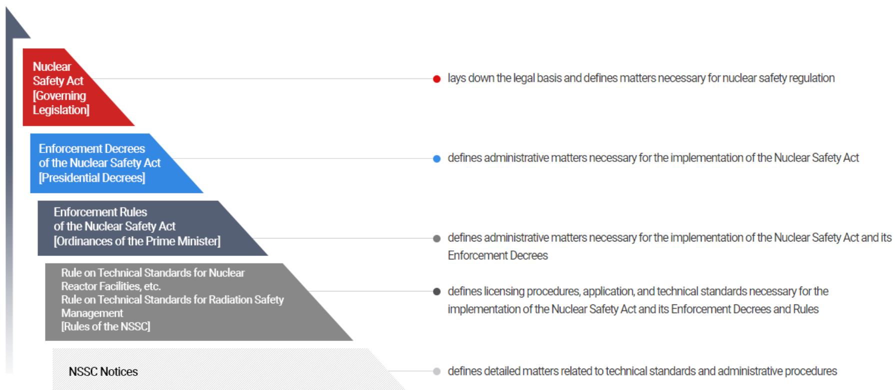


Figure 24. Structure of the Korean nuclear legislation system [33].

5.2. Expected Regulatory Issues on Repowering CPPs with SMRs

Since nuclear power plants require a high level of safety and security, their regulatory requirements are far more complex and specific compared to those of CPPs. Due to these differences in regulatory and legislative systems (Figure 25), repowering CPPs with nuclear power plants may lead to regulatory challenges.

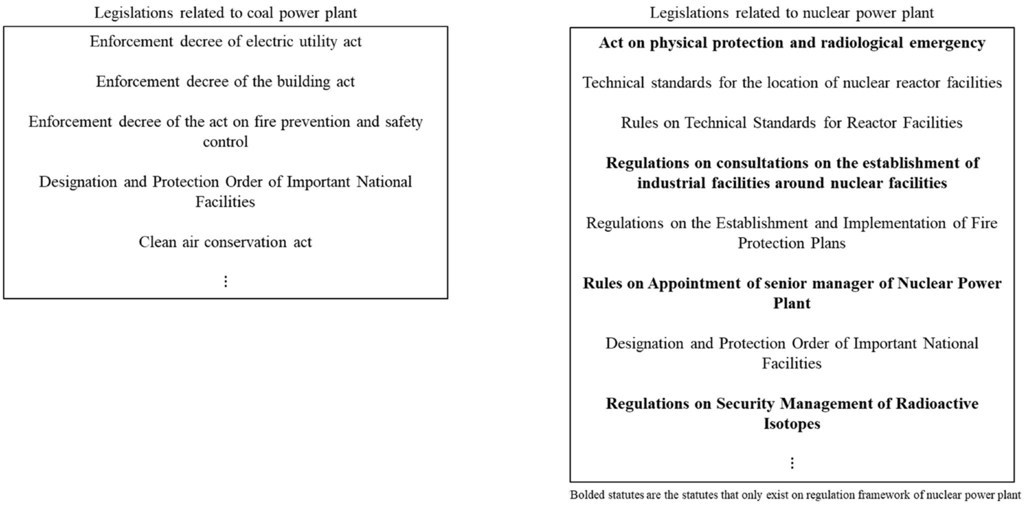


Figure 25. Comparison between legislation of CPPs and nuclear power plants [34].

5.2.1. Radiological Emergency Planning Zone [35]

Emergency Planning Zone (EPZ) is an area designated to prepare for uncontrolled releases of radioactive material by evacuating residents or distributing radiation protection drugs (Figure 26). Generally, EPZ is divided into two sections: Precautionary Action Zone (PAZ) and Urgent Protective Action Planning Zone (UPZ). PAZ is an area designated for preventive measures in radiation emergency situations, such as resident evacuation. UPZ is an area set aside for emergency protection measures, which are implemented based on radiological impact assessments and environmental monitoring.

EPZ requirements vary slightly across countries, as seen in Table 16, but certain similarities are observed. Most countries designate the evacuation area (corresponding to the EPZ) as being within 2 to 5 km of a nuclear power plant, while the post-accident protection area (corresponding to the UPZ) is set within 5 to 30 km. According to the Act on Physical Protection and Radiological Emergency, South Korea's nuclear safety guidelines define the EPZ as an area within 3 to 5 km of a nuclear power plant and the UPZ as an area within 20 to 30 km.

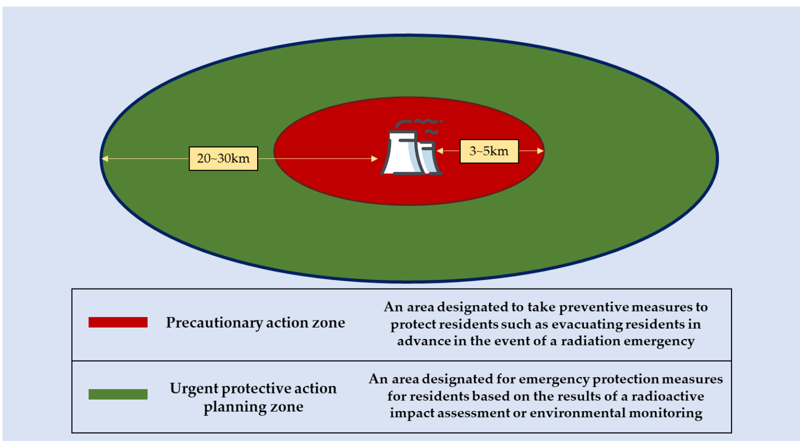


Figure 26. Concept of EPZ.

Table 16. Application of radiological EPZ in major countries in the world.

	Contents
IAEA	– Emergency Planning Zone: 3~5 km – Urgent protective action planning zone: 5~30 km
South Korea	– Emergency Planning Zone: 3~5 km – Urgent protective action planning zone: 20~30 km
U.S.	– Emergency Planning Zone: 3.2~8 km – Urgent protective action planning zone: 16 km
Hungary	– Emergency Planning Zone: 3 km – Urgent protective action planning zone: 30 km
Japan	– Emergency Planning Zone: 5 km – Urgent protective action planning zone: 30 km
Romania	– Emergency Planning Zone: 3 km – Urgent protective action planning zone: 10 km ※ Set Food Restriction Zone at 50 km separately
France	– 5 km: Evacuation area – 10 km: Indoor evacuation and thyroid protection drug preparation area
Germany	– 2 km: Pre-evacuation and preventive protection measures – 10 km: Evacuation and thyroid protection drug preparation – 25 km: Thyroid protection drug preparation
Netherland	– 5 km: Pre-evacuation and preventive protection measures – 10 km: Thyroid protection drug preparation – 20 km: Indoor evacuation preparation

Under South Korea's current regulatory and legislative framework, the EPZ is determined without considering the type or generation capacity of the reactor, which puts SMRs at a disadvantage for repowering CPPs. This can pose issues for coal repowering, as the current EPZ regulations do not account for the site locations of CPPs. For the commercialization of SMRs and the repowering of CPPs with SMRs, regulatory and legislative modifications are necessary, including adjusting EPZ boundaries based on a technical evaluation of the radiological source term specific to SMRs.

5.2.2. Restricted Facilities near Nuclear Power Plants

Several facilities can influence the stable operation of nuclear power plants and may also affect their safety. The Regulations on Consultations Regarding the Establishment of Industrial Facilities Around Nuclear Facilities define specific facilities that cannot be located within an 8 km radius of a nuclear power plant without the agreement of the relevant administrative agency (Table 17) [36]. To obtain such an agreement, an analysis of the impact of potential accidents at these facilities on the safety of the nuclear power plant is required.

In the context of repowering CPPs with SMRs, it is important to note that CPPs are generally located near ports, expressways, or railways to facilitate coal transportation. These facilities are included in the list of restricted facilities for nuclear power plants. Since the location of CPPs does not take into account the proximity of restricted industrial facilities required for nuclear power plants, problems may arise when repowering CPPs with SMRs due to the presence of these existing restricted facilities near CPP sites.

Table 17. Restricted industrial facilities near nuclear power plants.

Reason for Restriction	Types of Restricted Facilities
Facilities that causes explosion and vibration	– Facilities for manufacture, sale, storage, and transportation of gunpowder – Facilities for filling, supply, and sale of liquefied petroleum gas – Facilities for manufacture, supply, and storage of gas under control of "Urban Gas Business Act" – Manufacturing, sales, or storage place of high-pressure gas – Basic plan for railway construction under Article 7 of the "Railroad Construction Act" – Road routes under Article 2 and 22 of the "Road Act" – Establishment of the right to collect that requires permission under Article 15 of the "Seabed Mineral Resources Development Act"
Toxic substances discharging facilities	– Facilities that are likely to seriously disrupt the safety of nuclear facilities due to the discharge of toxic substances shall be as follows: ① Toxic substances subject to registration or permission under Article 20 (1) and Article 34 (1) of the Hazardous Chemical Substances Control Act. ② Substances that are required to obtain permission under Article 38 of the Occupation Safety and Health Act.
Other facilities that require consultation	– Oil storage facilities under Article 15 of the "Oil and Oil Alternative Fuel Business Act" – Final disposal facilities of wastes that must obtain permission under Article 25 and 29 (2) of the "Waste Management Act" – Hot spring development plan that requires the designation of the hot spring air protection area under Article 5 and 10 of the "Oncheon Act" – Underground waste development and utilization facilities – Master plan for ports under Article 5 of the "Port Act" – Pipeline construction plan that requires approval under Article 3 of the "Pipeline Safety Management Act"

5.2.3. Required Security Grade of Nuclear Power Plants

In South Korea, power plants are classified as facilities requiring national-level security, with security levels determined by the type and scale of the power plant. The Designation and Protection Order of Important National Facilities outlines the security levels for facilities that require military protection during emergencies, as well as the criteria for classifying such facilities (Table 18) [37].

Table 18. Definition of security levels for power plants in South Korea.

	Definition	Criteria for Classification
"A" class	Facilities that require the performance of integrated defense operations in a wide area to protect from destruction by enemy or paralysis of function	– Nuclear power plant
"B" class	Facilities that require the performance of integrated defense operations in some area to protect from destruction by enemy or paralysis of function	– Power plants with power generation capacity of 1 million kW or more – Substation that connects at least four banks among substations of 345 kV or higher

Table 18. *Cont.*

	Definition	Criteria for Classification
"C" class	Facilities that require short-term integrated defense operations to be carried out in limited areas from destruction by enemy or paralysis of function	– Power plants with power generation capacity of 500,000 kW or more – Major power plants on the Han River water system – Substation that connects at least three banks among substations of 345 kV or higher – Other power facilities requiring special protection

CPPs are classified into categories ranging from "A" to "C," depending on their electricity generation capacity and their importance to the national grid. In contrast, all nuclear power plants are designated as "A" class under the Designation and Protection Order of Important National Facilities. Given the higher security requirements for nuclear power plants compared to CPPs, repowering CPPs with SMRs must account for the increased security requirements as well.

6. Summary and Conclusions

To successfully reduce carbon emissions in South Korea's electricity generation sector, it is essential to retire operating CPPs promptly and replace coal-fired energy with low-carbon alternatives. However, since different low-carbon energy sources have varying capacity factors, the required installed capacity to replace coal will differ across these energy sources.

The required installed capacity of renewable and nuclear energy to replace coal-fired energy is first examined. The analysis indicates that integrating ESS with VRE can replicate the generation profile of coal-fired power, but the scale required is substantial, potentially leading to economic and societal challenges. For example, it was found that the ESS capacity needed for this transition would have to be over 182 times larger than the current market size, suggesting a significant increase in electricity prices. Additionally, the amount of energy stored in the ESS tends to be lower toward the end of the year compared to the beginning. This suggests that although the generation profile can be matched within a given year, storage deficiencies may increase in subsequent years due to insufficient storage levels. To balance energy storage levels at the start and end of the year, a larger ESS capacity would be required.

It is important to note that all analyses are based on 2023 generation and demand levels. Given the increasing trend in electricity demand, additional generation capacity will be necessary. Compared to VRE, SMRs can operate with load-following capabilities, eliminating the need for ESS. Thus, if SMRs are used to repower CPPs, the costs associated with transmission network construction and ESS installation required for VRE integration could be avoided.

This study also explored the thermodynamic feasibility of repowering CPP models that are currently under operation in South Korea using SMRs. Among the existing thermal power plants, 500 MW class plants were identified as the most promising targets for repowering, considering their remaining lifetime and capacity distribution. The repowering options selected involve reusing site infrastructure, electrical systems, heat sinks, and steam-cycle components due to its high economic potential. To avoid operating in the supercritical region, the IP turbine inlet of the thermal plant was chosen as the integration point for the SMRs. To maintain the efficiency of the IP turbine, a thermodynamic analysis was performed to ensure that the inlet conditions (temperature, pressure, and volumetric flow) were preserved. This analysis underscored the importance of carefully considering the thermodynamic implications of repowering to optimize the overall system performance.

A preliminary thermodynamic analysis was conducted for two PWR types and two HTGR types for the potential to replace coal boilers with nuclear reactors and reuse steam cycle components. The analysis revealed that HTGRs, due to their high-temperature operating conditions, do not require additional thermal energy for repowering. However, multiple HTGR units are necessary to compensate for the low volumetric flow rate. Conversely, PWRs require fewer units due to their high-volumetric flow rates but necessitate external thermal energy due to the low steam generator outlet temperature conditions.

Lastly, the study investigated issues in South Korea's current regulatory system if SMRs are used to repower CPPs. Several challenges are anticipated in repowering CPPs with SMRs, primarily due to the stricter safety and security requirements for nuclear power plants compared to CPPs. To enable the commercial realization of repowering CPPs with SMRs, substantial modifications to the existing regulatory framework will be required to fully utilize the advantages of SMRs.

While this study provides valuable insights into repowering CPPs with SMRs, further research is needed to address potential challenges and optimize the overall system design. A comprehensive analysis should be conducted to determine the optimal configuration for extrapolating and branching flows, considering factors such as pressure drops, heat transfer characteristics, and overall system efficiency. Moreover, ongoing discussions regarding the modification of nuclear safety regulations are essential to account for the technical differences between SMRs and large nuclear power plants in South Korea. Given that the current regulatory and legislative frameworks may not fully recognize the enhanced safety features of SMRs, modifications will be necessary to enable the effective and economical repowering of CPPs with SMRs, thereby reducing greenhouse gas emissions.

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