Original Article

Examination of excess electricity generation patterns in South Korea under the renewable initiative for 2030

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A B S T R A C T

According to the Renewable Energy 3020 Implementation Plan announced in 2017 by the South Korean government, the electricity share of renewable energy will be expanded to 20% of the total electricity generation by 2030. Given the intermittency of electricity generation from renewable energy, realization of such a plan presents challenges to managing South Korea’s isolated national electric grid and implies potentially large excess electricity generation in certain situations. The purpose of this study is: 1) to develop a model to accurately simulate the effects of excess electricity generation from renewables which would arise during the transition, and 2) to propose strategies to manage excess electricity generation through effective utilization of domestic electricity generating capabilities. Our results show that in periods of greater PV and wind power, namely the spring and fall seasons, the frequency of excess electricity generation increases, while electricity demand decreases. This being the case, flexible operation of coal and nuclear power plants along with LNG and pumped-storage hydroelectricity can be used to counterbalance the excess electricity generation from renewables. In addition, nuclear energy plays an important role in reducing CO2 emissions and electricity costs unlike the fossil fuel-based generation sources outlined in the 8th Basic Plan.

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1. Introduction

1.1. Background and literature review

Achieving deep decarbonization primarily with variable renewable energy (VRE), such as wind and solar generation, requires significant efforts in grid management [1]. The growing uncertainties from non-dispatchable VRE generation have demanded the existing low-CO2 baseload generators to pursue flexible load management options. South Korea is presently accelerating deployment of VRE under its Renewable Energy 3020 Implementation Plan, announced in 2017 [2], and its 8th Basic Plan for Long-term Electricity Supply and Demand (the 8th Basic Plan) of the same year [3,4]. Per these initiatives, 20% of national electricity demand is expected to be met through 58.5 GW2 of renewable energy from wind and solar plants by 2030, with reliance on nuclear generation decreasing to 23.9% (cf. 30.3% in 2016) [5].

Despite the anticipated benefits of VRE in terms of reducing greenhouse gas (GHG) emissions, the 8th Basic Plan has repercussions for the whole grid system of South Korea which is an isolated one without connections to neighboring countries. Whether the flexible operation of LNG along with energy storage outlined in the 8th Basic Plan, will be able to handle both daily and seasonal changes in net load (i.e., the total electric demand in the system minus VRE generation) requires further examination. The scale of the role of flexible operation of coal and perhaps also nuclear power plants in handling net load variations in South Korea also merits evaluation. Under the current decarbonization scheme, increasing reliance on coal-fired power plants would be undesirable. In light of the problem of excess electricity generation, a reexamination of the traditional role of nuclear power as baseload units casts doubt on the wisdom of the current nuclear phase-out policy. Continued use of nuclear units in baseload mode would result in overgeneration hours during which renewable plants’ power generation temporarily exceeds demand; at the same time, operating large-scale light water reactors in load-following mode...
would underutilize the capital invested in these nuclear plants.

South Korea's current nuclear phase-out policy contrasts sharply with its Intended Nationally Determined Contribution (INDC), published in 2016 [6]. In this document, the government had committed to a 37% reduction in GHG emissions [7], which was reduced to 26.4% in 2017. However, South Korea’s energy-intensive infrastructure presents major challenges to meeting this goal.

In 2019, industry accounted for over 60% of national final energy consumption, making it the largest contributor (55%) to South Korea’s GHG emissions [8]. As the country’s largest provider of emissions-free energy, nuclear energy with an excess electricity management strategy can better satisfy the government’s stringent emissions reduction requirements, providing the backbone of electricity supply at all hours of the day and in all seasonal conditions. Today, the country runs 24 nuclear reactors with a total capacity of over 23 GW [9], accounting for 26% of the electricity generated in 2019. This share comprises 80% of non-carbon emitting electricity in the nation with a fleet-wide capacity factor of 71% [3], serving as reliable baseload power [10]. The benefits of nuclear energy in deep decarbonization has also been examined in Petti et al. [11]. This study indicates that the cost of achieving major GHG emissions reductions increases significantly without the contribution of investment. Therefore, the least cost portfolio identified in the study all include a meaningful share for nuclear energy.

The Korea Electric Power Corporation’s (KEPCO’s) position grants VRE plants unlimited access to power grids with a capacity of 1 MW or below. Then, a higher penetration of VRE could bring up the overgeneration issue [12]. The 8th Basic Plan has set out to address this issue by introducing low levels of curtailment for large scale VRE plants or fossil-fueled power plants with flexible ramping capabilities (e.g., LNG plants). This approach is pursued as an alternative to investing in expensive transmission upgrades or storage technologies [13]. However, the solutions suggested in the plan have their respective constraints. For example, curtailment decreases the capacity factor of VRE projects and discourages VRE investments [14]. Also, the increasing use of fossil-fueled dispatchable resources could impede the government’s GHG reduction goal. A still controversial discussion is whether eliminating surplus generation inevitably leads to a preferable outcome of cost-effective power system operation [15–18]. Some of these studies assume that excess electricity is curtailed and not assigned any economic value, as handling the excess electricity would require additional technologies with additional costs (e.g., storage technologies) [15,16]. Others have recognized that the value of excess VRE can also be created by reducing the need for energy storage. For example, through a multi-energy carrier approach (e.g., district heating and hydrogen production) [17,18], grid configurations with excess electricity managing capability can become cost-optimum.

Recently, a study examined the effective utilization of industrial load as a means of transferring energy during a period of excess to displace or offset the use of fossil fuel generation [19]. In the context of South Korea’s evolving electric grid, the study focused on the short-run value of demand side flexibility from industrial load scheduling to incentivize a scheme to absorb surplus VRE generation. In fact, demand response (DR) has proven its potential as a cost-effective resource for balancing the grid system, providing grid operators with added benefits of contingency reserves (rapid response to a loss in supply), congestion management in transmission and distribution (T&D) networks, and deferral of peaking plants investment [20–22]. Another study investigated the capabilities of a wide range of DR resources (i.e., industrial loads and industrial processes) in the United States [23] by evaluating their performance for specific regional cases addressing overall economics and DR requirements.

South Korea has continued to promote the DR program as part of its efforts to maintain reserve margin (available capacity minus peak demand) at a certain level [24]. The Korea Power Exchange (KPX), South Korea’s wholesale electricity market operator, is in charge of day-ahead and 1-h ahead DR bidding markets. As of 2020, there were 4607 participants and the total registered capacity of DR resources at the market was more than 4.28 GW [25]. This capacity has grown rapidly since the start of the DR program in 2014. As the country looks to a hydrogen-based economy with a goal of decarbonizing the transportation sector, it is expected that massive electrolysis plants for hydrogen production would replace conventional steam methane reforming processes, leading to strong capacity growth in the DR market [26].

Since 2016, there has been a proposal to connect the electricity grids of Korea, China, Japan and possibly Russia through a cross-border power grid system, the Northeast Asia super grid [27]. However, the working groups of those countries have made only limited progress due to the lack of a cohesive political framework, such as the European Union, that could facilitate multilateral geopolitical cooperation to overcome market barriers [28]. This highlights the need for South Korea to seek a domestic approach that combines domestic industrial DR resources to manage the issue of excess electricity generation with high VRE penetration.

1.2. Motivation and contribution of this study

Motivated by the challenges and opportunities in South Korea's changing energy landscape, this paper presents a comprehensive assessment of the excess electricity generation profiles in South Korea. The work of Cho and Yim [19] investigated the short-run (i.e., one day) impact of the nation’s overgeneration issue using a Mixed-Integer Linear Programming method (MILP). Other references which have also modeled the electricity supply dispatch patterns of the 8th Basic Plan employed novel statistical approaches (e.g., Long-Short-Term Memory, Gated Recurrent Unit, System Advisor Model, and Facebook Prophet) [29,30]. The study of Lim et al. [29] has highlighted the seasonality of renewable generation patterns with respect to months and investigated the feasibility of the nationwide deployment of hybrid renewable energy systems in South Korea. Although, they factor in Korea’s future grid system, they do not incorporate an energy mix which is detailed in the 8th Basic Plan. Another study concerns how the transition from 7th Basic Plan to 8th Basic Plan would impact the VRE penetration level, and the total costs and emissions associated with South Korea’s electricity generation [30]. However, the literature only considers the monthly electricity load variation from the demand side and does not accounts for the monthly excess electricity generation from the supply side in terms of economic impact. Thus, this study attempts to address these gaps by using a one-year historical dataset from the KPX and by focusing on the monthly assessment of surplus VRE generation based on the 8th Basic Plan. We analyze the variation of VRE generation throughout the year and seek to leverage the economic benefits of excess electricity via nationwide DR. We then provide a path forward for a quick-ramping power plant investment (i.e., coal and LNG plants) to reach the pressing GHG emissions reduction goal.

VRE expansion has led to incremental shifts in the energy system, namely the adoption of batteries [31], implementation of Power-to-X production (e.g., hydrogen) [32–33], and changes in market structures [34]. The next step is factor in all these gradual changes and aggregate their net effects to examine the long-term impacts they will bring into the energy system. Due to the fact that Korea has four distinct seasons, this is of utmost importance to comprehend Korea’s seasonally varying demand curve and to investigate its monthly fluctuating supply from VRE assets. To
capture these effects, this work expands the existing literature by paying close attention to the monthly variations of excess electricity and the resulting changes in dispatch of coal, LNG and nuclear power sources in South Korea's 2030 power mix. In this setting, our model incorporates hourly dispatch scheduling, the contribution of DR to total grid flexibility, and the resulting impact on costs and GHG emissions. This paper also provides insight into the on-going transition to low-carbon energy while the country phases out nuclear power. We compare the performance of the nuclear renaissance plan (similar with 7th Basic Plan) and the 8th Basic Plan (ongoing nuclear phase-out plan) with respect to GHG emissions, total generation costs, and the amount of excess electricity generation. The novel analytical framework employed in this research will be directly applicable to countries with isolated national electric grids that need to reduce carbon emissions through affordable clean energy integration. European countries have a long history of policymaking when it comes to promoting renewables. Key areas covered by the block include reducing fossil fuel reliance, addressing global climate change, or supporting domestic technology development to increase their market competitiveness. However, as EU countries’ national grids are linked with each other, articulation of those goals in an isolated national grid system leaves open the question of whether accelerating renewable deployment is always a sensible and affordable approach to reach those goals. In this context, this paper aims to provide a review of the excess electricity generation issue in South Korea by using comprehensive historical generation data collected in 2017, based on the outlook of VRE capacities from the 8th Basic Plan. The results from each month illustrate changes in demand and supply of electricity along with weather conditions in South Korea. We choose the monthly-mean VRE penetration data for the base case. The ramp-rate of baseload generation sources, nuclear and coal, are set to zero, while only LNG plants are to have ramping capabilities in this scenario along with pumped-storage hydro (PSH) serving as an energy storage system (ESS).

The excess electricity generation pattern simulated in the base scenario is then modified to create four alternative scenarios. These modifications included varying the levels of VRE penetration, the operational mode of coal and nuclear power generation, and the installed capacity of nuclear power.

2.1.2. Scenario 2 — The high and low renewable penetration case

We introduce the second scenario to capture the possible ranges of excess electricity generation on a monthly basis by recognizing South Korea’s distinct weather conditions throughout all four seasons. While planning renewable plants, major consideration must be given to the large degree of variability driven by climate factors including air temperature, wind velocity, and solar radiation. Thus, this scenario a complementary perspective to understand the variations of the excess electricity generation pattern. To this end, the monthly-maximum and minimum VRE penetration data is used as part of the scenario. Finally, we conduct a comparison of excess electricity generation between Scenarios 1 and 2.

2.1.3. Scenario 3 — The case of semi flexible operation of coal fired power plants with LNG flexibility

Increased variability from VRE would substantially change the dispatch scheduling and the cost of supplying electricity. In South Korea, a minimum turn-down ratio of coal power plants (the ratio of the maximum capacity to the minimum capacity) is set to 50%, when they are operated in a load-following mode to meet seasonal electricity demand variations [37]. Thus, we investigate the capability of existing coal power plants in managing surplus generation along with the capability of the comparatively more flexible LNG plants. Subsequently, the results from this semi flexible operation is compared to Scenario 1.

2.1.4. Scenario 4 — The case of nuclear resurgence with load following of coal and LNG power plants

Increasing nuclear generating capacity along with higher VRE penetration could decrease GHG emissions by reducing dependence on fossil fuels [5]. This may also decrease the overall electricity generation costs due to the low cost of nuclear power in South Korea. To appraise this opportunity, we investigate the role of nuclear power in South Korea’s grid operation focusing on the value of reducing GHG emissions and electricity costs. The imposition of a carbon constraint on emissions emanating from the industrial sector could discourage their reliance on fossil fuels in favor of the excess electricity generation from low-carbon energy sources.

In this setting, we start with the assumption that the planned nuclear capacity (38.3 GW) in the 7th Basic Plan is retained in the 8th Basic Plan. We then examine how South Korea might reduce fossil fuel usage and GHG emissions from the industrial sector through increased use of nuclear power. Under the fixed total dispatchable power generation capacity (114.5 GW), the capacity of coal and LNG is proportionally reduced to 31.8 GW and 37.8 GW to accommodate the increase in nuclear capacity. Thus, the ratio of LNG to coal (i.e., 39.9 GW – 47.5 GW) is maintained as planned in the 8th Basic Plan. This nuclear resurgence scenario with semi flexible operation of coal power plants is compared with Scenario 3 to the

1.3. Organization of the paper

The remainder of this paper is organized as follows. Section 2 describes the data and lays out assumptions for the analysis. Section 3 mainly describes the results of the analysis. Section 4 discusses the simulation results and relevant policy implications for South Korea. Finally, Section 5 presents conclusions.

2. Methodology

This study proposes a model to simulate the possible excess electricity generation behavior in South Korea’s declared electricity supply plan, where renewables will see significant growth by 2030, accounting for 33.7% of total installed capacity. To compare possible paths for managing excess electricity generation, we define five scenarios (Section 2.1), resulting in varying quantities and time distributions of the surplus generation. Each of the scenarios provides a way to incorporate the entire solar and wind capacity declared in by 2030, but use different operation strategies to get there. Then, we develop an array of data and assumptions to conduct the scenario simulation (Section 2.2). The model for examining potential techno-economic issues in the 8th Basic Plan was defined (Section 2.3) to quantify total generation costs, GHG emissions, and the amount of surplus generation.

2.1. Definition of five simulation scenarios

2.1.1. Scenario 1 — The base case

The base case serves as a reference for the major changes expected to occur in South Korea’s evolving electric grid by 2030. The purpose of examining this scenario is to evaluate seasonal variations in the excess electricity generation pattern on a monthly basis under the 8th Basic Plan.

We construct the monthly-mean generation profiles by scaling historical generation data collected in 2017, based on the outlook of VRE capacities from the 8th Basic Plan. The results from each month illustrate changes in demand and supply of electricity along with weather conditions in South Korea. We choose the monthly-mean VRE penetration data for the base case. The ramp-rate of baseload generation sources, nuclear and coal, are set to zero, while only LNG plants are to have ramping capabilities in this scenario along with pumped-storage hydro (PSH) serving as an energy storage system (ESS).

The excess electricity generation pattern simulated in the base scenario is then modified to create four alternative scenarios. These modifications included varying the levels of VRE penetration, the operational mode of coal and nuclear power generation, and the installed capacity of nuclear power.

2.1.2. Scenario 2 — The high and low renewable penetration case

We introduce the second scenario to capture the possible ranges of excess electricity generation on a monthly basis by recognizing South Korea’s distinct weather conditions throughout all four seasons. While planning renewable plants, major consideration must be given to the large degree of variability driven by climate factors including air temperature, wind velocity, and solar radiation. Thus, this scenario a complementary perspective to understand the variations of the excess electricity generation pattern. To this end, the monthly-maximum and minimum VRE penetration data is used as part of the scenario. Finally, we conduct a comparison of excess electricity generation between Scenarios 1 and 2.

2.1.3. Scenario 3 — The case of semi flexible operation of coal fired power plants with LNG flexibility

Increased variability from VRE would substantially change the dispatch scheduling and the cost of supplying electricity. In South Korea, a minimum turn-down ratio of coal power plants (the ratio of the maximum capacity to the minimum capacity) is set to 50%, when they are operated in a load-following mode to meet seasonal electricity demand variations [37]. Thus, we investigate the capability of existing coal power plants in managing surplus generation along with the capability of the comparatively more flexible LNG plants. Subsequently, the results from this semi flexible operation is compared to Scenario 1.

2.1.4. Scenario 4 — The case of nuclear resurgence with load following of coal and LNG power plants

Increasing nuclear generating capacity along with higher VRE penetration could decrease GHG emissions by reducing dependence on fossil fuels [5]. This may also decrease the overall electricity generation costs due to the low cost of nuclear power in South Korea. To appraise this opportunity, we investigate the role of nuclear power in South Korea’s grid operation focusing on the value of reducing GHG emissions and electricity costs. The imposition of a carbon constraint on emissions emanating from the industrial sector could discourage their reliance on fossil fuels in favor of the excess electricity generation from low-carbon energy sources.

In this setting, we start with the assumption that the planned nuclear capacity (38.3 GW) in the 7th Basic Plan is retained in the 8th Basic Plan. We then examine how South Korea might reduce fossil fuel usage and GHG emissions from the industrial sector through increased use of nuclear power. Under the fixed total dispatchable power generation capacity (114.5 GW), the capacity of coal and LNG is proportionally reduced to 31.8 GW and 37.8 GW to accommodate the increase in nuclear capacity. Thus, the ratio of LNG to coal (i.e., 39.9 GW – 47.5 GW) is maintained as planned in the 8th Basic Plan. This nuclear resurgence scenario with semi flexible operation of coal power plants is compared with Scenario 3 to the
difference in electricity cost, excess electricity generation and GHG emissions.

2.1.5. Scenario 5 — The case of nuclear resurgence with load-following capability of NPPs

The benefits of nuclear flexibility are highlighted, which, in comparison to the other four scenarios, allows nuclear power plants to carry out load-following operations (i.e., 3 MW/hour-unit) for the same generation mix as in Scenario 4. We examine how moderate load-following operations of nuclear power plants impact the system results in terms of electricity cost, excess electricity generation and GHG emissions. To this end, the result is juxtaposed with those derived from Scenario 3 and 4 to assess the feasibility of increasing utilization of nuclear energy, the nation’s most cost-effective low-CO₂ resource, in a high VRE mix.

2.2. Data and layout assumptions

In order to implement the five different scenarios outlined in Section 2.1, variables (i.e., hourly wind and solar generation profile, coal ramp rate, and installed nuclear capacity) are assigned different values for each scenario. The following subsections cover the main features of each scenario, including the role of photovoltaic (PV), wind, nuclear, LNG, coal, and PSH, and excess electricity generation consumer (industrial loads).

Table 1 summarizes key assumptions used in the simulations and Fig. 1 depicts the diagram of the data collection and analysis procedure. To support a viable excess electricity balancing and its near-term implementation, we consider commercially available ESS technologies (i.e., PSH) in South Korea to the exclusion of other grid-scale storage technologies.

2.2.1. Renewable (non-dispatchable generation)

The target values for PV and wind in the 8th Basic Plan are used in the study while contributions from other renewable sources such as hydro (2.1 GW), biomass (1.7 GW), and waste heat (1.4 GW) are disregarded as they only garner a 3% share of South Korea’s 2030 generation capacity (dispatchable energy source). For the hourly PV generation profile, we select the Hadong PV station, which has achieved one of the highest solar cell efficiencies in South Korea. The target year considered is 2017 (See Fig. 2 (a)). The simulated PV generation pattern is created by scaling the Hadong PV station’s hourly profile from 3.5 MW [38] to the declared PV capacity goal for 2030, 33.5 GW. The Seongsan Windfarm with a 20 MW capacity serves as the reference for wind generation and its hourly generation profile in 2017 (See Fig. 2 (b)) [39] is scaled up to 17.7 GW to represent Korea’s planned hourly wind production for 2030. Though the wind farm generation performance varies throughout the year as a result of highly seasonal wind speeds, the higher installed PV capacity makes a greater contribution to overall variability in the averaged total renewable generation profile. Under the unlimited access assumption, solar and wind curtailment on the national grid is not considered for the purposes of this study.

2.2.2. Dispatchable generation

In the 8th Basic Plan, LNG generation is listed as the backup generation source for renewables due to its capability to quickly respond to fluctuations in energy supply. Thus, LNG generators are

Table 1
Summary of the simulation components and key assumptions.

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<th>Simulation components</th>
<th>Description of assumptions</th>
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| **Renewable sources (Non-Dispatchable)** | • The target values of PV and wind power in the 8th Basic Plan are used, while other renewable sources are neglected.  
• The generation profile for 33.53 GW of PV is evaluated by scaling up the hourly generation profile of the 3.5 MW Hadong PV station in South Korea [38].  
• The generation profile for 17.7 GW of Wind is evaluated by scaling up the hourly generation profile of the 20 MW Seongsan Wind Unit in Jeju, South Korea [39].  
• All PV and Wind generators receive guaranteed access and priority dispatch on the dispatch order. |
| **Dispatchable energy sources** | • In Scenario 1, 2, and 3, the total capacity of generation units is set to 20.4 GW (18 units), 39.9 GW (57 units), and 44.3 GW (230 units) for nuclear, coal and LNG units, respectively.  
• In Scenario 4 and 5, the total capacity of generation units is adjusted to 38.3 GW (35 units), 31.7 GW (45 units), and 37.8 GW (189 units), for nuclear, coal, and LNG respectively.  
• Unlike nuclear power, the exact number of planned coal and LNG generation units for 2030 has not been fixed, so we estimate the number of units by dividing the target capacity values by typical generation capacity of a unit (i.e., 700MW/coal generation unit and 200MW/LNG generation unit).  
• LNG power plants would be ramped at 20 MW/min.  
• PSH is able to instantly go from shutdown to full load and vice versa for charge and discharge.  
• The all charged electricity by PSH should be discharged by the end of the last time step.  
• There is no restriction on the PSH initial state of water stored in the upper reservoir. Thus, the PSH can either charge or discharge at the beginning of the 24-h period.  
• In Scenario 3 and 5, coal power plants would be ramped at 10 MW/min, reflecting the current operational practice of these generation technologies in South Korea [40].  
• In Scenario 5, ramp rate of nuclear power plants is also set to 3 MW/min, which is the mid-range value for the nuclear load-following in EU countries [41]. |
| **Electrical demand load** | • The electrical load pattern of South Korea in 2030 is defined by inflating the hourly average load profile in 2017 [43] by 30%, based on the annual electricity demand growth rate projected in the 8th Basic Plan. |
| **Electrical grid** | • Evaluation of the power grid is based on using the centralized dispatch approach, where full transmission of electricity is assumed without electricity loss during transmission and distribution.  
• The grid represents a system where all dispatchable and non-dispatchable units are electrically coupled, selling electricity to a single wholesale market. |
| **Excess electricity consumers (EEC)** | • To manage the time mismatch that can occur between fluctuating production and demand, Excess Electricity Consumers (EEC) are introduced.  
• EECs are end-users whose industrial loads are traditionally met by baseload energy sources.  
• EECs are compensated for the amount of excess electricity they can remove from the grid when needed.  
• There is no limit to the capacity of EECs available at each time interval, allowing us to assess the excess electricity that can be consumed in the simulation. |
| **Electricity cost** | • The fixed costs for power generation, PSH pumping mode (charge), and EEC compensation are considered for the simulation.  
• To represent the current cost of electricity generated by different sources in Korea, wholesale electricity price data is obtained from KPX [44].  
• The collected data are averaged over January 2017 to December 2019. |
the main source of grid flexibility to support the proposed increase in VRE generation in the nation's future electricity portfolio, while reducing the capacity factors (or capital utilization) of nuclear and coal power. For Scenarios 1, 2, and 3, the installed capacity and the number of generation units are set to 20.4 GW and 18 units, 39.9 GW and 57 units, and 44.3 GW and 230 units for nuclear, coal and LNG generators, respectively.

Since the exact number of planned coal and LNG generation units for 2030 has not been fixed, these numbers are estimated by dividing the target capacity values by the typical generation capacity of a unit (i.e., 700MW/coal generation unit and 200MW/LNG generation unit). To account for seasonal variations and annual maintenance cycles as a whole, each generation technology is set to have specified minimum and maximum generation levels, which in turn guarantee its minimum dispatched hours during the day (i.e., capacity factor). Each generation technology fleet is assigned an equal power level at each time interval in accordance with the same operating constraints. The ramp rate of LNG and coal power generating units are limited to 20 MW/min and 10 MW/min respectively, reflecting the current operational characteristics of

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**Fig. 1.** Diagram of the analysis procedure in this study.

**Fig. 2.** Hourly averaged renewable generation profile per month in 2017 for South Korea’s (a) Hadong PV station (3.5 MW capacity) and (b) Seongsan Wind farm (20 MW capacity).
these technologies in South Korea [40]. To represent the current operational characteristics, LNG power plants are set to perform load-following operations in all scenarios, while coal power plants were to perform load-following operations only under specific scenarios (see Scenarios 3, 4, and 5).

In Scenarios 4 and 5, the total capacity and its associated number of generation units considered are set to 38.3 GW and 35 units, 31.7 GW and 45 units, and 37.8 GW and 189 units, for nuclear, coal, and LNG, respectively. These are derived from the 7th Basic Plan, after consideration of the ratio of coal and LNG in the 8th Basic Plan. In Scenario 5, the ramp rate of nuclear power plants was set to 3 MW/min which is a conservative figure compared to the load-following operating mode of NPPs in EU countries [41].

PSH plants are currently seen as the most economically viable bulk electricity storage technology [1]. In the 8th Basic Plan, PSH is a key component to strengthening the nation’s grid stability against the adoption of large-size solar and wind VRE. Therefore, in all scenarios, PSH is used as ESS. The total installed capacity of PSH is anticipated to increase from 4.7 GW in 2020 and to 6.7 GW by 2030. Table 2 summarizes the status and future prospects of PSH in South Korea.

2.2.3. Electrical loads and the grid system

We simulate the power grid using a centralized dispatch approach, where full transmission of electricity is possible. Electricity loss during transmission and distribution are not considered in this study. The grid represents a system where all dispatchable and non-dispatchable units are electrically coupled, and the generated electricity is assumed to be sold to a single wholesale market. Under a centralized dispatch approach, all generation resources are scheduled as a whole, including excess electricity consumers, in order to find the least-cost combination. The average monthly South Korea electricity demand in 2017 is shown in Fig. 3. South Korea has developed its unique electricity demand patterns, showing annual peaks during the winter months. The relatively low electricity prices compared to residential heating fuel prices have accelerated South Korea’s transition from oil to gas to electricity in commercial and residential heating [42]. After showing a peak in winter, the electricity demand decreases until May. Then it begins to increase due to the increased demand from the use of cooling systems until August. The electricity demand then decreases during the autumn months and rises again in November and December. Therefore, South Korea is likely to experience overgeneration in the autumn months and rises again in November and December. To manage the time mismatch that can occur between fluctuating production and demand (i.e., excess electricity generation), excess electricity consumers (EECs) are introduced. EECs are end-users whose industrial loads are traditionally met by base-load energy sources (e.g., fossil fuels) [19]. Examples of EEC candidates whose electric demands are high enough to accommodate excess electricity generation on the grid include resistive heating (e.g., electric furnace) and electrolysis (e.g., for hydrogen production). However, it is assumed that there is no limit to the capacity of EECs available at each time interval, as this study aims to investigate the potential for large-scale excess electricity management.

2.2.4. Excess electricity consumers (industrial loads)

This study defines excess electricity at time $t$ as the hourly electricity generation exceeding demand (D), when considering the hourly generation from both non-dispatchable energy sources (NDG) and dispatchable generation sources (DG):

$$EEC(t) = D(t) - NDG(t) - DG(t)$$  \hspace{1cm} (1)

To manage the time mismatch that can occur between fluctuating production and demand, excess electricity consumers (EECs) are introduced. EECs are end-users whose industrial loads are traditionally met by base-load energy sources (e.g., fossil fuels) [19]. Examples of EEC candidates whose electric demands are high enough to accommodate excess electricity generation on the grid include resistive heating (e.g., electric furnace) and electrolysis (e.g., for hydrogen production). However, it is assumed that there is no limit to the capacity of EECs available at each time interval, as this study aims to investigate the potential for large-scale excess electricity management.

2.2.5. Electricity cost

In South Korea, the KPX compensates market participants (including PSH and DR) based on the hourly wholesale electricity price [24]. To represent the current cost of electricity generation by different sources in South Korea, we gather wholesale electricity price data from the KPX [44]. Considering the fall of natural gas and oil prices since shale gas development, the electric costs are taken from the target year of 2017, 2018, and 2019. The collected data are averaged over January 2017 to December 2019 (see Table 3). Table 3 shows that PSH’s wholesale price is the highest among all the energy sources, whereas nuclear’s wholesale price is the lowest. In our scheduling optimization model, the price parameters for solar and wind are not characterized based on the average as we assume solar and wind power having the full and

### Table 2

| Current PSH capacity and planned PSH projects in South Korea. |
|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|
| Cheongpyeong   | Samnangjin      | Muju            | Sancheong       | Yangyang        | Cheongsong      | Yecheon         | Project #1      | Project #2      | Project #3      |
| Units          | 2               | 2               | 2               | 2               | 2               | 2               | ND             | ND             | ND             |
| Capacity per unit (MW/unit) | 200             | 300             | 300             | 150             | 250             | 300             | 400            | 800            | 600            |
| Installed      | 400             | 600             | 600             | 700             | 1000            | 600             | 800            | 800            | 600            |
| Planned capacity |                |                 |                 |                 |                 |                 |                |                |                |
| Discharge duration (hour) | 6.5             | 6               | 6.9             | 7               | 8.3             | 9.5             | 8.3            | ND             | ND             |
| Charge duration (hour)  | 8.8             | 7               | 9.4             | 10.1            | 10.3            | 10.9            | 9              | ND             | ND             |

Note: ND stands for not determined.
The optimization model was developed to perform two tasks: (1) to reproduce and compute the balance of electricity (i.e., supply and demand of electricity) over each hour throughout one day’s time horizon, prioritizing the use of VRE up to their installed capacity, and (2) to determine the optimal operation of generation sources to minimize cost within operational constraints. The balance equation for the optimization model is as follows where \( X_{\text{load}} \) is the electrical demand and \( X_{\text{ren}} \) is the generation from solar and wind plants:

\[
X_{\text{Nuc}} + X_{\text{Coal}} + X_{\text{LNG}} + X_{\text{Ren}} + X_{\text{PSH,d}} = X_{\text{load}} + X_{\text{EEC}} + X_{\text{PSH,c}}
\]

(2)
PSH, $h_c$ and $h_d$ are the duration of PSH charging ($PSH_c$) and discharging ($PSH_d$) at rated power, respectively. The rated power of PSH generation ($PSH_d$) and PSH pumping ($PSH_c$) are set to 304.55 MW. Due to losses, $h_c$ and $h_d$ differ, even for equal rated pumping and generating power. Table 4 shows the variables and their values in each scenario.

### Table 4
Summary of the variables and their values in each scenario.

<table>
<thead>
<tr>
<th>Energy Source Index (s)</th>
<th>Variables</th>
<th>Scenario 1</th>
<th>Scenario 2</th>
<th>Scenario 3</th>
<th>Scenario 4</th>
<th>Scenario 5</th>
</tr>
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<tbody>
<tr>
<td>Coal</td>
<td>$T_C$ (GW)</td>
<td>39.9</td>
<td>39.9</td>
<td>39.9</td>
<td>31.7</td>
<td>31.7</td>
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<td></td>
<td>$N_c$</td>
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<td>57</td>
<td>57</td>
<td>45</td>
<td>45</td>
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<td></td>
<td>$t_c$ (MW/min)</td>
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<td>0</td>
<td>10</td>
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<tr>
<td></td>
<td>$L_c$ (%)</td>
<td>80</td>
<td>80</td>
<td>80</td>
<td>80</td>
<td>80</td>
</tr>
<tr>
<td></td>
<td>$h_c$ (hour)</td>
<td>9.35</td>
<td>9.35</td>
<td>9.35</td>
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<tr>
<td>LNG</td>
<td>$T_C$ (GW)</td>
<td>47.5</td>
<td>47.5</td>
<td>47.5</td>
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<td></td>
<td>$L_c$ (%)</td>
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<td>30</td>
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<tr>
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<td>$h_c$ (hour)</td>
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<td>100</td>
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<td>Nuclear</td>
<td>$T_C$ (GW)</td>
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<td>20.4</td>
<td>20.4</td>
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<td>PSH</td>
<td>$T_C$ (GW)</td>
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<td></td>
<td>$L_c$ (%)</td>
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<td>$h_c$ (hour)</td>
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<td>Statistical Data</td>
<td>Mean</td>
<td>Max and Min</td>
<td>Mean</td>
<td>Mean</td>
<td>Mean</td>
</tr>
</tbody>
</table>

3. Results

3.1. Scenario 1 - The base case

Fig. 5 shows the hourly variations in estimated electricity generation (MW) for 12 months from each energy source in Scenario 1:
(a) January, (b) February, (c) March, (d) April, (e) May, (f) June, (g) July, (h) August, (i) September, (j) October, (k) November, and (l) December. The figure reflects the results of the optimization calculation for each corresponding month as the estimated hourly electricity generation (MW) from each energy source for Scenario 1. The absolute value of each red bar (below zero MW) is the amount of excess electricity generated that should be consumed by EEC. VRE penetration and electrical demand variation lead to a monthly difference in excess electricity generation. Regarding the demand trend, the lowest electricity demand peak occurs in spring and fall at about 75 GW, and the highest electricity demand peak is in the summer and winter at over 90 GW. This, coupled with seasonal variations in wind power generation, results in PV generation being the most significant renewable contributor to the nation’s energy demand. With the focus on PVs, the highest share of VRE is between the hours of 11:00 and 15:00, when the highest PV generation occurs.

In the case of summer and winter, since electrical demand is relatively high and VRE penetration is not significant, no excess electricity is generated, in line with effective grid management. However, in spring or autumn, when electric demand is low and VRE penetration is relatively high, VRE results in excess electricity generation.

These results suggest that cost-effective grid management is imperative to the co-existence of a large generating capacity of VRE and affordable electricity. Results also show that relying only on the flexibility of the LNG and PSH fleets will be insufficient to address the intermittency of VRE and its related excess electricity generation.

3.2. Scenario 2 – The high and low renewable penetration case

Since energy generation by VRE is greatly influenced by weather, there is a limitation in analyzing excess electricity generation with only the average VRE penetration values. Therefore, the goal of this scenario was to present a range of excess electricity generation based on the minimum hourly generation and the maximum hourly generation of VRE for each month. The analysis is conducted in the same way as Scenario 1, but with the use of the maximum and minimum VRE generation values. Apart from these, the other variables needed for the analysis remain unchanged from Scenario 1.

Fig. 6 presents the excess electricity generation per day using three different VRE penetration levels (i.e., maximum, average, and minimum penetration) that occur during each month of the year. In South Korea, oversupply from PV is highly likely in the spring and fall seasons when weather conditions are favorable (e.g., fewer rain clouds and moderate temperature), thereby increasing excess electricity generation even when the combined renewable penetration (wind plus PV) is at its lowest level (see May and October in Fig. 6). When the penetration of VRE is at its maximum, excess electricity becomes dominant across the seasons.

All in all, the results imply that South Korea will face a mismatch between supply and demand in 2030 due to an oversupply from VRE. In the event of an unexpected situation involving a large increase in VRE output and an oversupply relative to demand, this might push the frequency of electricity to be outside the normal range, raising the possibility of a system-wide blackout.

3.3. Scenario 3 – The case of semi flexible operation of coal fired power plants with LNG flexibility

One of the assumptions in the base case (Scenario 1) is that coal power runs as base-load units and does not participate in load-following. The results from Scenario 1 showed that a large amount of excess electricity is generated in spring and fall. When the penetration of VRE is high due to good weather conditions (Scenario 2), our analysis also showed large quantities of excess electricity generation all year round.

As far as electrical grid system operations are concerned, coal-fired power plants are capable of scaling down to a minimum generation level of 50% at a rate of about 10 MW/min. By introducing this in the third scenario, we tried to ascertain the differences in excess electricity generation that could result from load-following of coal-fired power plants. Using the average VRE generation case from Scenario 1 and the methodology discussed above while implementing flexible operational capability of coal-fired power plants, we determine the amount of coal-fired powers’ manoeuvring capability needed to reduce the excess electricity supplied to the grid.

The results are given in Fig. 7. They indicated that excess electricity generation that should be consumed by EEC is eliminated through load-following of coal and LNG, along with the operation of PSH.

This manoeuvring approach for coal-fired power plants is a somewhat realistic proposal of how South Korea could manage its electric power system. However, it will be necessary to adjust generation levels at both coal and LNG power plants when low electrical demand or high VRE penetration occurs, according to the energy portfolio of the 8th Basic Plan. In addition, it is noteworthy that this scenario was based on the averaged VRE penetration data. Therefore, it implies that excess electricity generation can occur when VRE penetration reaches higher levels, despite load-following of coal-fired power plants and the operation of PSH as ESS. This also implies that expansion of VRE can cause a large shortfall of revenues from LNG and coal-fired power plants due to significant reduction in overall power generation.

Experience from historical cases shows that high penetration of VRE can induce substantial volatility in electricity price [47–51], thereby worsening the economics of energy generation due to decreases in system marginal price. Moreover, a high share of VRE demands high system integration costs, including profile cost, namely connection costs, balancing costs, and grid costs to accommodate steep power changes [49,52]. As such, it is necessary to identify additional industrial end-users that could take advantage of excess electricity generation so that the grid can accommodate variable energy generation and thus make successful implementation of the 8th Basic Plan a reality.

3.4. Scenario 4 - The case of nuclear resurgence with load following of coal and LNG power plants

The current South Korean administration is proposing a nuclear phase-out policy to reduce national reliance on nuclear power while increasing VRE penetration [6]. However, under the given energy-intensive industrial structure of South Korea, reducing GHG emissions while supporting continuous economic growth is a daunting task. In this sense, optimizing the utilization of existing low carbon energy sources is a necessary option deserving serious consideration. South Korea’s past heavy reliance on nuclear power means there is a low carbon energy source available during the transition to renewables to support the country’s economic growth.
In this section, using the energy mix proposed by South Korea’s 8th Basic Plan, we analyzed the impact of increasing the proportion of nuclear power generation and decreasing coal and LNG generation as part of the supply and demand scenario.

We compared the base case scenario (Nuclear: 20.4 GW, Coal: 39.9 GW, LNG: 47.5 GW) to the nuclear resurgence scenario (Nuclear: 38.3 GW, Coal: 31.7 GW, LNG: 37.8 GW) in terms of the purchase price of electricity (for KPX), GHG emissions, and excess electricity generation. In this nuclear resurgence scenario, we set the ramp rate of coal and LNG as 10 MW/min, and 20 MW/min, respectively [40]. The averaged GHG emission value for each energy source (see Table 5) was obtained from a report by the World Nuclear Association [53]. Fig. 8 compares the month-by-month results.

With the increase in the capacity of nuclear energy in the nuclear resurgence scenario, the price of electricity becomes lower (by about 6%) (See Fig. 8 (a)) while the GHG emissions (See Fig. 8 (b)) are significantly reduced (by almost 30% for most months). The results also show that excess electricity generation occurs in spring (April, May), and fall (October) (See Fig. 8 (c)). This demonstrates that nuclear energy, as a baseload solution, generates electricity with the twin benefits of low GHG emissions and low generation cost. In this regard, the South Korean government’s current nuclear phase-out policy works against the goal of reducing electricity generation cost and GHG emissions. Alternatively, an effective scheme for the utilization of the excess electricity can be developed including industrial use customers to take advantage of the surplus electricity for economically and environmentally competitive electric load management. This way, nuclear power could maintain its role as a cost-effective provider of low-carbon electricity without incurring techno-economic penalties for not operating in a load-following mode.3

3.5. Scenario 5 - The case of nuclear resurgence with load-following capability of NPPs

Analogous to nuclear resurgence case in Scenario 4, Scenario 5 is intended to clearly demonstrate the impact of excess electricity, economics, and GHG emissions according to the ramping approach of nuclear power. Therefore, we use the capacity of each energy source in Scenario 4, adding the ramp-rates of nuclear power plants (3 MW/min) [41]. We then compared the results with Scenario 3 (Nuclear: 20.4 GW, Coal: 39.9 GW, LNG: 44.3 GW) and Scenario 4 (Nuclear: 34.06 GW, Coal: 29.9 GW, LNG: 34.3 GW), in which only coal and LNG power plants participate in load-following (coal: 10 MW/min and LNG: 20 MW/min). The results are also summarized in Fig. 8.

The results show that the increased nuclear capacity with flexible operations of nuclear, LNG, and coal could significantly reduce excess electricity and GHG emissions. The price of electricity becomes 7% lower in Scenario 5 compared with Scenario 3 and is similar to the prices in Scenario 4. The GHG emissions show significant reductions in Scenario 5 by approximately 30% relative to Scenario 3, once again similar to Scenario 4. This is because Scenarios 4 and 5 basically use an identical nuclear capacity of 38.3 GW. Therefore, the electricity cost and GHG emissions in Scenarios 4 and 5 do not vary much since both simulations use nuclear energy as the top choice in views of its flexibility and affordability. Looking at the pattern of excess electricity generation for this Scenario, however, we see that the amount becomes significantly lower with load-following of NPPs (Scenario 5) relative to when NPPs were placed in baseload operation (Scenario 4).

To summarize, flexible operations of coal and nuclear power plants along with LNG and PSH have been found to minimize excess electricity generation while balancing renewable’s intermittency. Moreover, possessing a high capacity of nuclear energy under flexible operation has been shown to increase the overall cost-effectiveness of the energy system in South Korea while reducing GHG emissions. The results indicate the need of finding willing industrial end-users that can take advantage of excess electricity generation, thus accommodating a mismatch between supply and demand in electricity.

4. Discussion

4.1. Policy implications of the results

With the planned rapid increase in VRE generation, the issue of excess electricity generation deserves serious consideration in conceiving South Korea’s national energy plan. Excess electricity generation has implications not only for electricity costs but also for electric power quality and grid stability. Although building large-scale ESS to back-up the nationwide excess in electricity is feasible, this option currently is prohibitively expensive. Adding PSH, for its own right, would also suffer from the severe limitations due to country’s geography. Hence, this leads to the unavoidable conclusion that South Korea needs to devise country-specific alternatives for managing excess electricity in the grid. The results of this study illustrated that excess electricity generation is inevitable under the scenarios that are consistent with the nation’s commitment to GHG emissions reductions.

Excess electricity generation in South Korea is an opportunity to explore a symbiotic business relationship between traditional energy sources (e.g., a nuclear power plants) and an industrial DR (e.g., electrolysis-based hydrogen production). In a carbon-constrained world, the industrial DR at a nationwide scale is likely to considerably increase the demand for low-carbon energy (i.e., nuclear and renewable) to meet the industry-wide goal of GHG emissions reductions and economic competitiveness. In the case of South Korea, the current government initiative to transition to a hydrogen-based economy adds additional incentive to moving in this direction. To reduce electricity costs and GHG emissions.
simultaneously, forming a coalition between low carbon and cost-effective energy sources (nuclear and VRE) and effective DR management policy to utilize excess electricity would prove essential. Our analysis shows that unsynchronized generation patterns formed from baseload nuclear plants and non-dispatchable renewables (mostly PV) will make up a majority of surplus electricity generation in South Korea’s future grid. As such, it would be prudent to implement policies that trigger grid management technology innovations and regulatory arrangements that maximize excess electricity utilization for all suppliers and DR markets. This regulatory arrangement could include:

1. Forming a joint task force that retains authority over plant licensing, security, and emergency planning.
2. Allowing flexibility in the non-electric usage of nuclear energy.
3. Rearranging business ownership models for fast market expansion. Moreover, it will be critical to establish national standards for excess electricity production, transmission, and utilization.

4.1.1. Hydrogen production

First, South Korea should consider how to use the excess electricity in a way that could further reduce GHG. One possibility is the production of hydrogen which can be used for a variety of energy options. According to the Roadmap for Hydrogen Economy, the current South Korean administration aims to bolster the hydrogen economy by promoting hydrogen generation. The target hydrogen production cost in 2030 is 4,000 KRW/kg, and the target hydrogen production cost in 2040 is expected to go down to 3,000 KRW/kg. These production costs are based on a target hydrogen supply of 1.94 million tons/year by 2030, and 526 million tons/year by 2040 [26]. The primary option proposed by the Roadmap is importing hydrogen from overseas and/or producing hydrogen from existing fossil fuel sources. The problem with the latter approach is that relying on fossil fuels for hydrogen production defeats the purpose of clean energy promotion, as the practice chips away at any gains realized from expanding VRE sources. The former is also controversial, as increasing imports of any energy source would increase South Korea’s energy security vulnerability.

Applying the excess electricity from the expansion of VRE to the hydrogen production industry is a plausible option in support of the national goals to increase hydrogen production. That being said, it will be a challenge to induce hydrogen producers to rely solely on intermittent excess electricity produced from VRE. When the amount of VRE generation suddenly fluctuates during the hydrogen

---

**Table 5**

<table>
<thead>
<tr>
<th>Technology</th>
<th>Mean</th>
<th>Low</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>888</td>
<td>756</td>
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<td>Natural Gas</td>
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<tr>
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<tr>
<td>Hydroelectric</td>
<td>26</td>
<td>2</td>
<td>237</td>
</tr>
</tbody>
</table>
production process, the producers’ ability to provide a stable flow of hydrogen will be undermined. Likewise, if the excess electricity is insufficient at the time when hydrogen production is needed, there will be a disruption in hydrogen supply.

When factoring in the government’s commitment to GHG reduction and a hydrogen economy, identifying an economical, stable and low GHG option for hydrogen production is paramount. And herein lies where nuclear power can play a key role. Studies have indicated that hydrogen production using the fluid temperatures of conventional nuclear reactors results in a lower cost of hydrogen production and is at a higher technology readiness level compared to hydrogen production using VRE sources [54,55]. As South Korea’s nuclear power capacity factor currently remains at about 70% (which is quite low compared to South Korea’s average historical performance level of ~90%), further increasing the capacity factor of nuclear energy has the advantages of not only ensuring stable hydrogen production but also enhancing energy security by reducing the number of foreign energy imports.

In accordance with this analysis, we suggest linking hydrogen production to the intermittent excess electricity from VRE penetration and base-load energy by growing nationwide nuclear power capacity factor. Such a development would facilitate achieving large-scale hydrogen production based on the 8th Basic Plan for Long-term Electricity Supply and Demand. The approach would lower the volatility of electricity price while supporting the goal of reducing GHG. What is more, it will bring about long-term and resilient economic benefits, as South Korea will be more self-sufficient. It is essential for the South Korean government and the utility (i.e., Korea Hydro Nuclear Power) company to start engaging in meaningful planning and implementation strategy discussions to support such a framework for the future.

4.1.2. Other industrial load options for DR participation

Industrial use customers and general use customers account for a similar proportion of the total electricity customers participating in the demand response market in South Korea [56]. In the case of industrial uses, the manufacturing sector accounts for the majority of the customer base with chemical production and steel-making, each covering about half.

Unlike blast furnaces which rely on fossil fuel-based heat [57], electric arc furnaces are a more sustainable option, as they produce high quality steel from steel scraps by applying electric arc heat, which results in lower resource utilization and thus carbon emissions across the board. The main possible downside to this more sustainable alternative is the cost factor, as electric arc furnaces consume large amounts of electric energy which results in a higher bill for the operator [58].

Demand response could be an opportunity for these electric arc furnace plants to reduce their operational costs by switching the most energy-intensive industrial operation time to off-peak hours [58]. For instance, the large electric furnace operator can participate in the demand response market by adjusting their operating schedule by as little as about one to 2 h per day [59].

Our study showed that as VRE penetration increases, not only the requirements on flexible generation of electricity (such as frequent power load-following) increase but demand response expansion also becomes necessary. It is essential to establish an infrastructure that promotes DR market participation by
individual customers with various energy demand patterns along with increasing the role of those users currently participating in South Korea’s DR market (e.g., steel making and chemical production).

4.2. Limitations of this study

This study has been carried out using several simplifying assumptions as a first effort to assess the effects of monthly excess electricity generation. First among these assumptions is uniform renewable generation patterns throughout all of South Korea. By relying on data from the Hadong PV station and Seongsan Windfarm, which have the highest generation efficiency, in this study, this study facilitates planning for the worst-case scenario in terms of excess electricity generation management. Furthermore, we do not consider system integration costs (including profile cost, connection costs, balancing costs, and grid costs) of VRE in the total wholesale electricity price calculation, meaning this study does not present the increase in total electricity cost that would result from high penetration of VRE. Lastly, since small modular reactors (SMRs) are increasingly being considered as a potential means of managing the intermittency of VREs, future studies should further explore the dynamics of SMR deployment to balance electricity supply and demand.

5. Conclusion

This study predicts the patterns in potential excess electricity generation in South Korea based on the targets laid out in the 8th Basic Energy Plan, particularly the significant increase in VRE penetration by 2030, and suggests the optimum combination of nuclear, coal, and LNG resources to effectively manage possible excess electricity generation. A mixed-integer linear programming method is used to formulate an optimal dispatch schedule based on the capacities of available power generation sources. This optimization scheme includes matching the hourly supply of all generation sources to electricity demand in order to minimize the total cost of electricity. To identify a main contributor to variability in South Korea’s 2030 grid, the monthly variation patterns of excess electricity are estimated. We also assess the amount of monthly excess electricity generation, total costs and GHG emissions in five different cases (i.e., monthly variation analysis, the ramping approach of LNG and coal, and nuclear resurgence compared against the base case).

Based on the results obtained in the study, the following observations can be made. First, there is a high probability of generating excess electricity when PV and wind output remains high, especially in spring and fall. Solar power will be the main variability-causing factor under the VRE expansion policy. Second, despite its cost and GHG emissions, LNG generation capacity in South Korea will remain important to support the current VRE expansion policy. Our analysis, however, shows the flexibility of the LNG and PSH fleets will be insufficient to address intermittency of VRE sources and to handle the resulting excess electricity generation. Consequently, coal-fired power plants (or nuclear power plants) will have to stay online for load-following operation as a back-up energy source. Third, to achieve both GHG emissions reduction and to minimize electricity cost, it is crucial to recognize the value of reliable low-carbon generation technologies. Finally, South Korea should increase the use of nuclear power plants to catalyze the practical and effective use of excess electricity generation. Operating large-scale light water reactors in a very conservative load-following mode without underutilizing the capital cost of nuclear plants would be worthwhile. This approach would further South Korea’s twin goals of building a national hydrogen economy and reducing GHG all while fostering economic prowess.

Currently, South Korea is ranked 64th in the world in its energy security and its environmental sustainability index is at 84th. In this situation, the way forward to improve on both fronts would be to promote the use of domestic (or semi-domestic), low-carbon energy sources. Accordingly, a complementary use of nuclear power and VRE sources provides a sustainable foundation for an evolving energy system and capacitates better utilization of excess electricity by the industrial sector. Realizing the potential of these proposals depends on how the schemes can be implemented in the national energy grid system. Therefore, understanding the specific characteristics of the national grid and tailoring them to meet the changing energy inputs and outputs will be paramount.

This study stresses that, by consolidating the techno-economic bases of the DR program or the national hydrogen initiative in managing potential excess electricity generation, a supportive political coalition could be formed around the use of reliable low-carbon energy sources (i.e., nuclear power and VRE). Policy interventions that include a diversified low-carbon electricity portfolio are critical in substituting for conventional standby capacity services from coal or LNG power plants. In the end, this model would be consistent with South Korea’s INDC target.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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hydrogen production technologies for nuclear hybrid energy systems, Prog.

Nomenclature

Abbreviations

DR: Demand Response
ECC: Excess Electricity Consumers
GHC: Greenhouse Gas
INDC: Intended Nationally Determined Contribution
KKEPCO: Korea Electric Power Corporation
KPX: Korea Power Exchange
LNG: Liquidified Natural Gas

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MILP: Mixed Integer Linear Programming
PSH: Pumped-Storage Hydropower
PSH,c: Pumped-Storage Hydropower Charge
PSH,d: Pumped-Storage Hydropower Discharge
PV: Photovoltaics
SMR: Small Modular Reactor
VRE: Variable Renewable Energy

Symbols

\[ CNuc: \text{Electricity cost (KRW/MWh) associated with nuclear} \]
\[ CCoal: \text{Electricity cost (KRW/MWh) associated with coal} \]
\[ CEEC: \text{Electricity cost (KRW/MWh) associated with EEC} \]
\[ CLNG: \text{Electricity cost (KRW/MWh) associated with LNG} \]
\[ CPSH,c; \text{Electricity cost (KRW/MWh) associated with PSH,c (charging: pumping water)} \]
\[ CPSH,d; \text{Electricity cost (KRW/MWh) associated with PSH,d (discharging: releasing water)} \]
\[ D(t): \text{Electricity demand at time } t \]
\[ DG(t): \text{Hourly generation from dispatchable generation sources at time } t \]
\[ h_{\text{charge}}: \text{Pumped-Storage Hydropower charge time at rated power} \]
\[ h_{\text{discharge}}: \text{Pumped-Storage Hydropower discharge time at rated power} \]
\[ L_s: \text{Minimum generation level of each energy source} \]
\[ N_s: \text{Total unit of generation resource } s \]
\[ NDG(t): \text{Hourly generation from non-dispatchable energy sources at time } t \]
\[ r_s: \text{Ramp rate of dispatchable generation technology of each energy source } s \]
\[ s: \text{Index for generation technologies, } s \in \{ \text{Nuc, coal, LNG, PSH,c, PSH,d} \} \]
\[ t: \text{Index for the hours simulated, } t \in T = \{1 \text{ through } 24\} \]
\[ TC_s: \text{Total installed capacity of each energy source } s \]
\[ U_s: \text{Maximum generation level of each energy source } s \]
\[ X_{\text{load}}: \text{Electrical demand (MW) at time } t \]
\[ X_{\text{Nuc}}: \text{Generation output (MW) at time } t \text{ for nuclear} \]
\[ X_{\text{Coal}}: \text{Generation output (MW) at time } t \text{ for coal} \]
\[ X_{\text{LNG}}: \text{Generation output (MW) at time } t \text{ for LNG} \]
\[ X_{\text{Ren}}: \text{Generation output (MW) at time } t \text{ for renewable} \]
\[ X_{\text{EEC}}: \text{Number of participating Excess Electricity Consumers (industrial loads) at time } t \]
\[ X_{\text{PSH,c}}: \text{Generation output (MW) at time } t \text{ for Pumped-Storage Hydropower charge} \]
\[ X_{\text{PSH,d}}: \text{Generation output (MW) at time } t \text{ for Pumped-Storage Hydropower discharge} \]
\[ \eta: \text{Round trip efficiency of Pumped-Storage Hydropower} \]