

Article

Modelling the RES Balanced Integration in Forecasting the Power System's Long-Term Development

Tetiana Nechaieva ¹, Volodymyr Derii ¹, Artur Zaporozhets ^{1,2,3,*} and Viktor Denysov ¹

¹ Department of Forecasting the Electric Power Complex Development, General Energy Institute of National Academy of Sciences of Ukraine, 03150 Kyiv, Ukraine; nechaieva_tp@nas.gov.ua (T.N.); derii_vo@nas.gov.ua (V.D.); denysov_va@nas.gov.ua (V.D.)

² International Institute for Applied Systems Analysis, 2361 Laxenburg, Austria

³ Green Technology Research Center, Yuan Ze University, Taoyuan 320, Taiwan

* Correspondence: a.o.zaporozhets@nas.gov.ua; Tel.: +38-044-294-67-22

Highlights

What are the main findings?

- PtH enables balanced integration of high shares of variable renewable energy.
- The 2040 scenario shifts generation toward RES, BESSs, and electric boilers.

What are the implications of the main findings?

- PtH reduces renewable curtailment and improves system flexibility.
- Coupled electricity–heat planning supports reliable energy system decarbonisation.

Abstract

The growing integration of variable renewable energy sources (VRES) challenges power system flexibility and may cause curtailment due to excess capacity, grid constraints, or operational and market factors. Power-to-Heat (PtH) technology can mitigate these issues by coupling electricity and district heating sectors, providing additional flexibility and supporting decarbonisation. This study develops a long-term generation capacity expansion model that integrates PtH and district heating system (DHS) operation to achieve balanced VRES penetration. The model includes DHS heat demand balances and links electricity and heat via thermal power plants, combined heat and power (CHP) plants, and PtH units. The methodology is applied to Ukraine's Integrated Power System and district heating demand through 2040, employing typical daily load profiles discretised into six four-hour segments. Results demonstrate the feasibility of deploying PtH electric boilers during the non-heating season, when high RES and base load nuclear generation create surplus electricity. These boilers convert excess wind and solar power into thermal energy for district heating, displacing natural gas-fired technologies and simultaneously decarbonising electricity and heat supply.

Keywords: variable renewable energy sources; curtailment; sectoral coupling; energy balances; long-term forecasting model; power system; district heating system; Power-to-Heat technology



Academic Editor: Anamika Yadav

Received: 1 June 2026

Revised: 20 July 2026

Accepted: 23 July 2026

Published: 27 July 2026

Copyright: © 2026 by the authors.

Licensee MDPI, Basel, Switzerland.

This article is an open access article distributed under the terms and conditions of the [Creative Commons Attribution \(CC BY\)](https://creativecommons.org/licenses/by/4.0/) license.

1. Introduction

The large-scale renewable energy sources (RES) integration, driven by their key role in achieving the decarbonisation targets for the energy sector, has significantly altered

the operating conditions and requirements for power systems. This primarily concerns the variability and unpredictability of solar and wind power plants, driven by natural meteorological and seasonal factors. Even with modern forecasting models, uncertainty remains significant, which complicates dispatch operations [1]. An increase in electricity generation from RES, such as solar power plants (SPPs) and wind power plants (WPPs), may lead to capacity curtailment if the power system lacks sufficient flexibility to maintain a balance between generation and consumption. According to a global assessment by the IEA [2], delays in implementing measures to support RES integration could jeopardise up to 15% of wind and solar power generation by 2030 and are likely to result in a 20%-less-than-expected reduction in CO₂ emissions in the energy sector. The successful integration of such variable RES (VRES) maximises the amount of energy that can be obtained safely and affordably, minimises costly measures to ensure system stability, and reduces dependence on fossil fuels [2].

The IEA study outlines six phases of growth in the SPPs and WPPs impact, corresponding to their level of integration [2]. The low integration of VRES in phases 1 through 3 can be ensured with a negligible impact on the operation of the power system, and can be resolved by increasing flexibility through the optimisation of dispatch processes, improved forecasting accuracy, the introduction of greater flexibility and system services, ensuring an industrial response to demand, and the improvement of grid infrastructure. Phases 4 to 6, with significant integration of VRES, where their generation can cover almost the entire demand, are characterised by a substantial increase in their impact on system operation, requiring a fundamental transformation of the power system. From phase 4 onwards, when VRES generation is sufficient to meet a significant portion of electricity demand, problems with excess power arise during periods of high generation and low demand. During these periods, the power from these RES must be curtailed, reducing economic efficiency.

Such forced reduction (known as “curtailment”) of VRES power is implemented to maintain balance in the power system due to operational constraints on other generators and the absence of demand response, grid expansion, storage or export [3]. International experience with wind and solar power curtailment [3,4] indicates three primary causes: excess generation, grid constraints, and operational or market factors.

To avoid curtailment, key measures include deploying energy storage systems, expanding interregional interconnectors, implementing demand response, and optimising the generation mix [5]. Storage (electrochemical, pumped hydro, and thermal) allows excess generation to be stored and used during peak demand hours. Successful examples of countries’ strategies for reducing volatility when integrating VRES into their electricity grids have included advanced energy storage technologies, grid modernisation and flexible power balancing [1]. A study for Japan [6] showed that increasing interregional flows could reduce forced curtailment by 79%, as surplus generation can be exported to regions with power deficits. Demand-side management ensures that consumption is shifted to hours of high VRES generation. Optimisation of the capacity mix aims to reduce the share of generation that creates “hard” constraints. Modelling using Japan as an example showed that reducing installed nuclear capacity could reduce constraints by 95–97% in certain scenarios. Grid modernisation should aim to eliminate local “bottlenecks” that create constraints. This is particularly relevant for regions with rapid growth in solar generation.

The most effective measure for reducing VRES constraints is sectoral coupling, integrating RES with sectors such as district heating and transport. Brown et al. [7] emphasise that focusing on the electricity sector not only means ignoring significant greenhouse gas emissions in other energy-consuming sectors, such as heating and transport, but also neglecting important sources of flexibility in these sectors.

The integration of the electricity and heat supply sectors is often considered a particularly promising direction, given the relatively low costs of producing heat from electricity and storing it [8]. The use of renewable electricity for heating purposes can help decarbonise the heating sector and facilitate the integration of RES into the power system, providing additional flexibility. A study [9] demonstrated the advantages of the integration of Ukraine's power system and the centralised heat supply system through the electrification of the centralised heat supply system using autonomous renewable energy sources and nuclear power plant capacity, which provides high technological capability, economical efficiency, reliability, and ecological sustainability for each component.

Power-to-Heat (PtH) technology is a comprehensive flexibility system that integrates the electricity and heating sectors and is one of the key mechanisms for reducing constraints in systems with a high share of VRES [5]. Combining renewable energy sources with PtH technology and seasonal thermal energy storage can significantly increase the flexibility of district heating systems, reducing the restrictions on renewable energy production [10]. DHS systems can help support PtH technologies, enabling thermal demand to respond flexibly to system requirements [11]. PtH technology employs electric heat generators (EHGs) that convert surplus electricity from RES into heat, thereby increasing system flexibility and reducing balancing costs. The key benefits of using PtH include utilising surplus generation during periods of high VRES output, replacing fossil-fuel-based thermal energy in district heating, and reducing the need for thermal power plants (TPPs) to manoeuvre, which alleviates system constraints [12].

Studies show that PtH technology can reduce RES power curtailments by 30–70% [8], cover up to 40% of heat demand [13], and be more cost-effective than electrochemical storage for daily surpluses [5]. This technology is particularly effective in countries with high heat demand (e.g., Finland, where over 80% of household energy is spent on heating).

One of the most common and economically attractive solutions for converting electricity into heat in municipal and industrial processes is electric boilers, which are characterised by low initial cost, compactness, flexibility, no chimney required, zero emissions when using renewable electricity, quiet operation, and ease of maintenance [14].

Furthermore, combined heat and power plants (CHPPs) play a significant role in integrating the electricity and heat sectors, providing centralised and industrial process heat supply. The optimal combination of CHP plants with PtH technologies and thermal energy storage systems in district heating systems (DHSs) can facilitate the flexible integration of the electricity and heating sectors, contributing to an increase in the share of renewable energy sources in the power system and the decarbonisation of the heating sector [8,12,13,15].

Developing pathways towards a sustainable power system with a high level of renewable energy integration requires the use of energy modelling tools that account for key factors, such as the evolution of fossil fuel prices and technologies, as well as the natural dynamics of renewable resources [16]. In long-term power system development models, power curtailments are typically accounted for by an optimisation variable representing the difference between available and utilised renewable generation, which allows for the modelling of excess renewable generation [17], whilst PtH is treated as a flexible demand that utilised part of this surplus [8,12]. In long-term planning models, PtH is typically used to optimise RES integration, reduce peak loads and improve the efficiency of heat supply. This reduces RES curtailments and system costs, as the curtailment variable is typically incorporated into the model's objective function as a penalty or opportunity cost, allowing the optimisation to find an economic trade-off between investments in flexibility and an acceptable level of unused generation [5,8]. A comparative study of eight power system models [18] shows that the differences in the obtained results occur mainly through

the different model scope, rather than through mathematical formulations or technology parameters. The key source of differences in the results is the structure of the model and the coverage of sectors. Variations in sectoral integration within the models significantly reduce constraints and alter the structure of investments.

A systematic review of solutions for ensuring flexibility in 100% renewable energy systems confirms that RES curtailment is an integral part of an economically optimal solution in scenarios with a high share of renewables [14]. Around a quarter of the studies reviewed [14] model curtailment as a low-cost form of flexibility that avoids excessive investment in energy storage or grid reinforcement. In this context, PtH acts as one of the key flexibility tools, capable of absorbing excess generation over time scales ranging from hours to days, reducing the need for expensive electrochemical storage and improving the efficiency of RES integration. Thus, in modern long-term optimisation models, curtailment and PtH are viewed as complementary mechanisms that ensure the economically optimal integration of high shares of renewable generation.

At the same time, the use of PtH technologies and BESSs requires detailed consideration of their operational dynamics over a 24 h period, as well as the utilisation of thermal energy from EHG in the DHS. This necessitates the development of an approach to modelling the long-term optimal operation of the power system by considering the DHS's thermal energy balance.

The aim of this paper is to model the balanced integration of VRES in forecasting the long-term development of the power system, considering technological measures to prevent curtailment of their output and the synergies from joint operation of the power system and the district heating system.

2. Materials and Methods

To model the balanced integration of a significant volume of VRES into the power system, a study was conducted using a mixed-integer model of the long-term development of the power system's generation capacity [19]. As previously noted, to avoid forced limitation of renewable energy supply when the flexibility of the power system is insufficient to ensure its well-balanced operation, it is appropriate to apply storage systems to shift excess renewable energy generation from periods of surplus output to periods of peak electricity consumption, as well as PtH technologies that convert excess renewable-generated electricity into heat energy. The model, therefore, required refinement to incorporate the heat output of PtH technology in line with the available demand from district heating systems.

In the mathematical model for forecasting the long-term development of the generation capacity structure of the electric power system [19], the power variables included in the balance of load coverage of the power system for new installations sheets are derived using integer variables X_{nt} representing the number of units of each type n available at each stage t , forward-looking period T and their unit capacity P_n , taking into account the technical limitations of their operation:

$$d_{nst}^{MN} X_{nt} P_n \leq Y_{nsdzt} \leq d_{nst}^{MX} X_{nt} P_n, \quad \forall t = 1 \div T, s \in S, d \in D, z \in Z, \quad (1)$$

where Y_{nsdzt} —variable representing the total power of new generating units of type n at time t , used to cover z zone of the typical day d of season s of the electricity load schedule (ELS), MW; S —typical seasons, D —typical days, and Z —zones of daily ELS; $d_{nst}^{MN}, d_{nst}^{MX}$ —the coefficients that account for the minimum and maximum allowable operating load of the unit, $0 \leq d_{nst}^{MN} < 1$ and $0 < d_{nst}^{MX} \leq 1$.

Existing type units at the beginning of the forecasting period are also represented in the model by their unit capacity P_e and the exogenous parameter N_{et} , which represent their

numbers at stage t . In the ELS coverage balances, existing type units are represented by the variable Y_{eszt} , which is limited by their total installed capacity, similar to Formula (1):

$$d_{est}^{MN} N_{et} P_e \leq Y_{eszt} \leq d_{est}^{MX} N_{et} P_e, \forall t = 1 \div T, s \in S, z \in Z. \quad (2)$$

This modelling approach allows for the dynamics of capacity commissioning and decommissioning over the forecast period to be considered, subject to the duration of their life cycles, investment conditions and constraints, as well as changes in forecast electricity demand. The criterion for the optimal long-term development of the power system's generation capacity structure is the minimisation of the total costs of new generating plants and the operating costs of existing capacity, whilst meeting typical daily electricity load schedules. The costs of new plants are calculated through commissioning, considering the dynamics of their components, in particular changes in unit capital investment, fuel prices, and charges for emissions of pollutants and greenhouse gases (GHGs).

To account for the role of BESS in the mathematical model of the long-term development of the power generation capacity structure of the electricity system, a transition was made from the traditional separate coverage of the three-zone daily schedule to its representation as successive time intervals throughout the day [20]. To achieve that, the hourly profile of the daily load schedule is divided into intervals (segments) of constant power and a specified duration, which, when aggregated over the daily energy volume, must correspond to the actual 24 h ELS. This is formalised as follows:

$$\sum_{\tau=1}^{24} D_{sd\tau} \Delta\tau = \sum_{z=1}^Z D_{sdz} h_{dz}, \quad (3)$$

where $D_{sd\tau}$ is the power of the ELS at hour τ of a typical day d in season s , in MW; $\Delta\tau$ is the hour of the day; Z is the total number of hourly segments of the ELS; D_{sdz} is the power during time interval z of a typical daily ELS, in MW; and h_{dz} is the duration of segment z of the daily ELS d , in hours.

This enabled the modelling of the charge–discharge dynamics of the storage system, accounting for its state of charge and available capacity. A similar approach was used to model the participation of pumped-storage hydroelectric plants (PSHPs). The use of storage systems involves transferring surplus power from wind- and solar-power plants [21].

To account for the variability of renewable energy generation and electricity demand, the model considers consecutive time intervals (segments) across typical days of the year, reflecting the need for flexible technologies and energy storage. The load and power of RES in these segments are assumed constant and determined by averaging their actual hourly data [21]. Based on the obtained averaged values, loads and RES power profiles are determined for each of the segments of typical days, which are used to generate loads and power parameters for WPPs and SPPs for each time of the forecast period in accordance with the total annual electricity demand and the forecast installed capacities of these RES.

Ensuring the flexibility of the power system when integrating significant volumes of non-guaranteed wind and solar power capacity is achieved by including in the balances the generation technologies capable of rapidly adjusting their power output and start operation (gas turbine and gas reciprocating engine units), using BESS to shift surplus RES generation to peak consumption hours, and PtH technologies to convert it into thermal energy consumed in district heating systems.

The application of PtH technology for the balanced integration of significant amounts of renewable energy requires the consideration of their heat output into district heating systems. To address this, heat demand balances have been incorporated into the mathematical model to forecast the long-term development of the power system's structure. The link

between the electricity and heat energy balances is ensured through combined heat and power technologies (CHPPs, cogeneration units) and PtH technology.

PtH technology in the segment coverage balances of daily ELSs is determined by variable electricity consumption:

$$\sum_{k=TPP,CHP,NPP} \sum_{f \in F} a_{ksfz} Y_{ksfzt} + \sum_{k=HPP} (Y_{ksdzt} + V_{sd}^P) + \sum_{k=SPP,WPP} a_{ksdz} N_{kt} P_k + \sum_{k=AB,BESS,PSHP} (R_{ksdzt} - Z_{ksdzt}) - Z_{sdzt}^{EB} + z_{sdzt}^I - z_{sdzt}^E = D_{sdzt}^E \quad (4)$$

where a_{ksfz} —coefficients that take into account possible operating modes f of technologies within a specific range from the minimum operating power to the rated capacity (thermal power plants (TPPs), combined heat and power plants (CHPPs), and nuclear power plants (NPPs)); Y_{ksdzt} —hydropower plants (HPPs) variable power, MW; V_{sd}^P —water discharge power of HPPs for a typical day d of season s [19], MW; a_{ksdz} —WPP and SPP power profile in the corresponding segment z of the daily generation schedule; N_{kt} —the number of WPPs and SPPs with unit capacity P_k for each stage of the forecast period [21]; R_{ksdzt} , Z_{ksdzt} —PSHP or storage system (grid-connected BESSs or those operating in conjunction with RES (AB)) generation-consumption power variables when covering z segment of the ELS of day d in season s [20], MW; Z_{sdzt}^{EB} —consumption power variable of PtH technology, MW; and z_{sdzt}^I , z_{sdzt}^E —import-export power variables, MW. New and existing technologies of the same type, denoted by the indexes n and e in Equations (1) and (2), are indicated by the index k in this equation.

The model considers two types of energy storage systems—grid-connected BESS, used for power system balancing, and storage systems within hybrid RES power plants, which utilise their surplus generation in energy arbitrage mode.

To ensure the balanced operation of the power system when integrating RES, the energy they generate can be fed directly into the grid or, in the event of a surplus in the power system, be charged by the storage system within its available energy capacity, current state of charge and anticipated demand during subsequent time segments of the day. Unused surplus generation from RES must be fed into the grid [21]. That is, the total generated power from WPPs and SPPs consists of three variables—power fed directly into the grid Y_{ksdzt}^G , power stored in the storage system Y_{ksdzt}^A , and power not fed into the grid Y_{ksdzt}^C :

$$a_{ksdzt} N_{kt} P_k = Y_{ksdzt}^G + Y_{ksdzt}^A + Y_{ksdzt}^C, \quad k = WPP, SPP, \quad \sum_{k=WPP,SPP} Y_{ksdzt}^A = Z_{(k=AB)sdzt} \quad (5)$$

Forced curtailment of power output from WPPs and SPPs into the grid can be avoided by using electric heat generators (EHG) PtH technologies that convert renewable electricity surplus into thermal energy for DHS:

$$Z_{sdzt}^{EB} \leq \sum_{k=WPP,SPP} Y_{ksdzt}^C \quad (6)$$

If it is not possible to fully consume the excess VRES power using PtH technology, the remaining power to be curtailed $Y_{sdzt}^{CUR} = \sum_{k=WPP,SPP} Y_{ksdzt}^C - Z_{sdzt}^{EB}$ is added to the power balances of ELS with a negative value and to the functional with a specific curtailment cost coefficient, which corresponds to the payments made to RES producers when their generation is curtailed.

The most suitable technology for this is electric boilers, which require a low capital investment and can operate in variable-load modes at low operating costs. In the model, the variable power consumption of EHG in each segment of the daily ELS is limited by

their available installed capacity, which for each stage of the forecast period is determined according to the unit capacity P^{EB} and the available quantity n_t^{EB} :

$$Z_{sdzt}^{EB} \leq P^{EB} n_t^{EB}. \quad (7)$$

The coverage balances of the segments of the daily thermal load schedules (TLSs) of the DHS are formed in a similar manner to the coverage balances of the ELSs, using thermal energy generation technologies, the supply of thermal energy from CHPPs and cogeneration units, as well as excess electricity from RES converted into EHG. The coverage balance for each segment of the daily TLS is recorded as:

$$\sum_{k=CHP} Y_{ksdzt}^H + \sum_{k=HB} H_{ksdzt} + H_{sdzt}^{EB} + z_{sdzt}^{HI} = D_{sdzt}^H, \quad (8)$$

where Y_{ksdzt}^H —TPPs, CHPPs and cogeneration units heat supply power, MW; H_{ksdzt} —heat supply power of type k heat generation units from the HB set (fossil fuel boilers, biofuel boilers, etc.), MW; H_{sdzt}^{EB} —EHG heat supply power, MW; z_{sdzt}^{HI} —artificial variable for balancing the heat production-consumption imbalance, defining the amount of power deficit during segment z , MW; and D_{sdzt}^H —heat consumption power in the corresponding segment z of the daily TLS, MW.

The variability in heat output power across different heat generation technologies is limited by the number and individual capacity at the relevant stage of the forecast period, considering the seasonal availability of their use:

$$H_{ksdzt} \leq k_{ks} n_{kt} P_k^H, \quad (9)$$

where P_k^H —unit capacity of heat generation technology of type k , MW; n_{kt} —number of units of type k at stage t ; and k_{ks} —availability coefficient of units of type k in season s .

The heat output power variable from combined production technologies is limited in accordance with the electrical power of their operation in the ELSs, considering the technological ratio between thermal and electrical power:

$$Y_{ksdzt}^H \leq \kappa_k^{E2H} \sum_{f \in F} a_{ksfz} Y_{ksfdt}, \quad \kappa_k^{E2H} > 0, \quad k = CHP, \quad (10)$$

where κ^{E2H} —the ratio between electrical and thermal power.

The EHG thermal energy is utilised in the corresponding segment of the daily TLS in accordance with power consumption in the ELS, considering the efficiency η^{EB} of converting electrical energy into thermal energy:

$$H_{sdzt}^{EB} = Z_{sdzt}^{EB} \eta^{EB}. \quad (11)$$

The condition for the use of electric boilers in modelling is the conversion of all consumed electrical energy into thermal energy over a day:

$$\sum_z H_{sdzt}^{EB} h_{sdz} = \sum_z Z_{sdzt}^{EB} h_{sdz} \eta^{EB}, \quad (12)$$

where h_{sdz} —duration of the ELS segment z on a typical day d of the season s , hours. Since, in accordance with the modelling assumptions, the typical day must be divided into segments in the same way in the electrical and thermal load schedules, the same duration parameters are used for both.

The use of energy storage systems is modelled based on values such as nominal available energy capacity, maximum permissible charge and discharge rates, round trip

efficiency, and the state of charge of the storage. The battery's state of charge at the beginning of each time segment is determined based on the energy accumulated at the beginning of the previous segment and the energy charged or discharged during that period [20]:

$$SoC_{ksdzt} = SoC_{ksd(z-1)t} + (Z_{ksd(z-1)t} - R_{ksd(z-1)t} / \eta_k^{RT}) h_{sdz}, k = AB, BESS, PSHP, \quad (13)$$

where SoC_{ksdzt} —variable representing the amount of charged energy in the storage at the start of the z -th time segment, MWh and η_k^{RT} —round trip efficiency of the storage unit. The amount of charged energy in each storage unit segment is limited by its available capacity. The state of charge of the storage unit at the start of the first segment of the day is set according to the modelling conditions—the storage unit is either empty or charged to a specified percentage of its nominal capacity. The PSHPs use is modelled in a similar manner.

Prevention of simultaneous charging and discharging of the storage unit in the corresponding segment of the daily ELS is modelled using Boolean variables in the charging and discharging power constraints:

$$R_{ksdzt} \leq b_{ksdzt}^R P_k^R, Z_{ksdzt} \leq b_{ksdzt}^Z P_k^Z, b_{ksdzt}^R + b_{ksdzt}^Z \leq 1, k = AB, BESS, PHPS, \quad (14)$$

where b_{ksdzt}^R, b_{ksdzt}^Z —Boolean variables (0 or 1); P_k^R and P_k^Z —the maximum discharge/charge powers of the storage unit, MW.

In the model, it is assumed that all the energy stored during the day will be used within the same time period:

$$\sum_z R_{ksdzt} h_{sdz} = \sum_z Z_{ksdzt} h_{sdz} \eta_k^{RT}, k = AB, BESS, PHPS. \quad (15)$$

In accordance with the thermal energy balance modelling DHS, the costs of heat production—including EHG PtH technology—have been added to the model's functional [21], which minimises system-wide costs:

$$\sum_{t=1}^T \left[\sum_k C_{kt}^c X_{kt}^N P_n + \sum_{s \in S} \sum_{d \in D} \left(\sum_{k=TPP, NPP, CHP} \sum_{f \in F} C_{kfsdt}^v Y_{kfsdt} + \sum_{k=HPP} \sum_{z \in Z} C_{ksdzt}^v Y_{ksdzt} h_{sdz} \right) T_{sd} + \right. \\ \left. + \sum_{s \in S} \sum_{d \in D} \sum_{z \in Z} \left(\sum_{k=WPP, SPP} (C_{kst}^v Y_{ksdzt}^G + c_{kt}^g Y_{ksdzt}^{CUR}) + \sum_{k=BESS, AB, PSHP} (c_{kt}^{ar} R_{ksdzt} + c_{kt}^{az} Z_{ksdzt}) \right) h_{sdz} T_{sd} + \right. \\ \left. + \sum_{s \in S} \sum_{d \in D} \sum_{z \in Z} (c_{t,z}^i z_{sdzt}^i + c_{t,z}^e z_{sdzt}^e + c_t^{EBC} Z_{sdzt}^{EB} + c_t^{EBH} H_{sdzt}^{EB}) h_{sdz} T_{sd} + \right. \\ \left. + \sum_{s \in S} \sum_{d \in D} \sum_{z \in Z} \left(\sum_{k=CHP} c_{kt}^{GH} Y_{ksdzt}^H + \sum_{k=HB} c_{kt}^H H_{ksdzt} + k_t^{HI} z_{sdzt}^{HI} \right) h_{sdz} T_{sd} \right] \rightarrow \min, \quad (16)$$

where C_{kt}^c —levelized specific fixed costs of technologies, \$/MW; X_{kt}^N —the number of new type k units installed at time t ; C_{kfsdt}^v —levelized specific variable operating costs of the units, adjusted to the stage t at the start of their operation, \$/MWh; T_{sd} —number of typical days d in the season s ; c_{kt}^g —coefficients corresponding to the current green tariff levels and the maximum projected auction price levels for the appropriate WPPs and SPPs, \$/MWh; c_{kt}^{ar}, c_{kt}^{az} —cost of discharging/charging energy storage systems, \$/MWh; c_t^i, c_t^e —prices of imported/exported electricity, \$/MWh; c_t^{EBC}, c_t^{EBH} —cost of electricity consumption/heat supply by EHG, \$/MWh; c_t^{GH} —the cost of heat supplied by combined-cycle power plants, \$/MWh; c_{kt}^H —the cost of heat generation at boiler houses, \$/MWh; and k_t^{HI} —coefficient of the balanced variable for conditionally imported thermal energy, \$/MWh.

3. Results and Discussion

The model was tested using forecasts of electricity and heat consumption from the draft update of the National Energy and Climate Plan (NECP) [22].

The development of renewable energy capacity within the power system is based on the figures set out in the National Action Plan for the Development of Renewable Energy by 2030 [23], with projected growth trends up to 2040 [24], which are consistent with the data presented in the NECP draft.

The development of nuclear capacity envisages using the existing nine NPPs with an installed capacity of 7.8 GW, completing two units at the Khmelnytskyi NPP, and bringing the four nuclear power units into operational service.

Existing thermal generation, following extensive damage and partial restoration, can provide around 3.8 GW of available capacity. The assumptions for testing the model are that coal-fired power units at thermal power plants and coal-fired combined heat and power plants will be decommissioned after 2035, in accordance with Ukraine's declared commitments to phase out coal-fired generation by 2035.

Given the current shortage of domestic capacity, electricity imports from EU countries are crucial for balancing demand; this depends on the transmission capacity of Ukraine's cross-border interconnections with ENTSO-E countries, which has been estimated in line with the forecast trends set out in the draft update of the NECP. The limits on electricity export/import variables for the IPS have been established in accordance with the baseline scenario of the projected dynamics of interconnection capacity [22]. Export capacity remains unchanged until 2040 at 650 MW, whilst import capacity increases from 2100 MW to 3350 MW.

Increasing the flexibility of the power system to ensure the proper integration of power plants with non-guaranteed capacity based on VRES (SPPs and WPPs) is envisaged using highly manoeuvrable capacity with rapid start-up capability and BESS. System balancing is also achieved through HPPs, PSHPs and manoeuvrable TPPs.

The BESS development is growing rapidly, driven by legislative initiatives and the need to RES balance, particularly SPPs. Currently, 600 MW BESS are connected to the grid, whereas in 2024, there were only 2 MW [25], and technical specifications have been issued for the connection of a further 1.4 GW of new energy storage. A significant contribution to the growth of energy storage has been made by DTEK RES, which, in partnership with the American company Fluence Energy, has launched an energy storage complex with a power capacity of 200 MW and a storage capacity of 400 MWh across six sites, and by KNESS, which in 2025 completed the construction of eight energy storage parks with a total capacity of over 140 MWh [26].

The characteristic ELSs for winter and summer days were derived from the actual hourly loads of typical days based on 2019 data, converted into six-segment daily ELS with each time interval lasting 4 h. Based on the determined segment-specific load factors (Table 1) and forecast annual electricity consumption, the load for each segment on a typical day of the year during the forecast period was calculated. Typical working days for the heating and non-heating seasons were selected, with a transition from hourly power to the average power for each 4 h segment of the day (six segments in total).

Table 1. The six-segment 4 h electrical load profiles for typical days of the seasons.

Time Segment	1	2	3	4	5	6
Day of the heating season	0.765	0.852	0.991	0.961	1.000	0.887
Day of the non-heating season	0.550	0.603	0.707	0.729	0.699	0.713

The specific capacity factor (CF) of SPP and WPP were also calculated for typical days in the two seasons based on data on their actual total power output IPS in 2019 (Table 2).

Table 2. Segment-specific CF for SPP and WPP for typical days of the two seasons.

Time Segment	1	2	3	4	5	6
SPP						
Day of the heating season	0.000	0.010	0.147	0.116	0.000	0.000
Day of the non-heating season	0.000	0.076	0.521	0.512	0.150	0.000
WPP						
Day of the heating season	0.501	0.483	0.432	0.419	0.532	0.630
Day of the non-heating season	0.263	0.221	0.132	0.245	0.376	0.319

The specific heat load was determined in accordance with the established daily hourly TLSs of the DHS. The methodology described in [27] was used to construct these graphs. With its use, the annual share of heat energy supplied by Ukraine's DHS and its distribution across the months of the year were determined. The average daily thermal output of the boiler houses was then determined in accordance with the formula:

$$P_i = 1.163 Q_i / N_i / 24, \quad (17)$$

where P_i —average thermal power of boiler houses in the i -th month, MW; 1.163—conversion factor between MW and Gcal/h; Q_i —the amount of thermal energy produced by the boiler houses in the i -th month, Gcal/h; N_i —the number of days in the i -th month; and 24—the number of hours in a day.

To construct an hourly graph of boiler house power during the non-heating period, the results of a statistical analysis of hourly hot water consumption in DHS, as presented in [28], were used. For each hour of the working and non-working day, based on the data presented in [28], the ratio was determined as follows:

$$k = \frac{V_j}{V_{avg}}, \quad (18)$$

where V_j —volume of hot water consumption in the j -th hour; V_{avg} —average volume of hot water consumption per day.

The distribution of boiler house power output over a 24 h period was determined using the formula:

$$P_j = k P_i, \quad (19)$$

where P_j —boiler house power at the j -th hour of the day, MW.

The results of the calculations of hourly heat power outputs for an average day in May are shown in Figures 1 and 2.

January was selected as the representative month for the hourly capacity of boiler houses during the heating season. In this month, the average thermal capacity was 5876.2 MW. The hourly capacity was calculated using Equations (17) and (19). The coefficient k was determined from the actual daily hourly capacity schedule for Kharkiv CHP-3 during the heating season. The results of the calculations are shown in Figure 3.

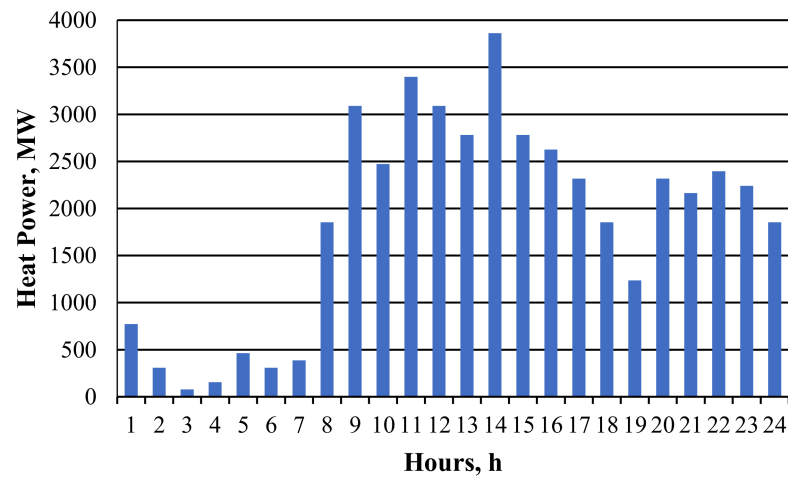


Figure 1. Hourly heat power of district heating boiler houses on a weekend without the heating season.

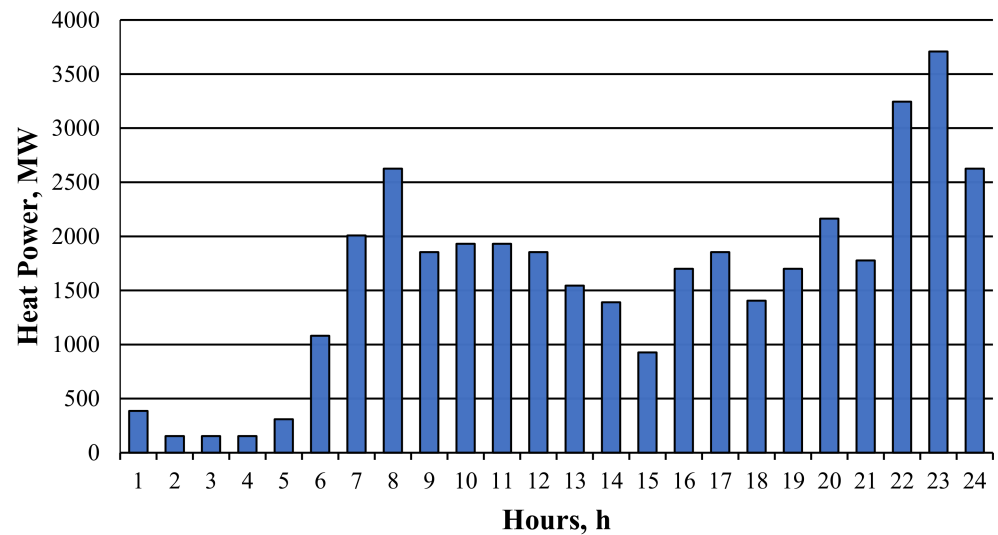


Figure 2. Hourly power of district heating boiler houses on a working day, without the non-heating season.

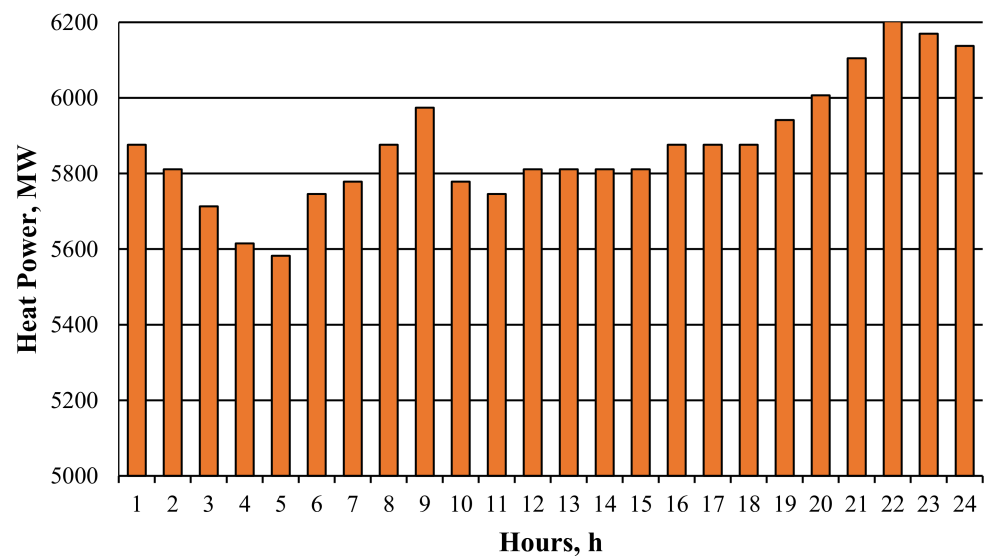


Figure 3. Hourly power of district heating boiler houses during the heating season.

Power fluctuations between 1 and 10 a.m. are due to fluctuations in hot water consumption, whilst those between 6 p.m. and midnight are due to fluctuations in hot water consumption and a drop in outdoor air temperature.

The hourly power outputs of boiler houses for typical days in the heating and non-heating seasons, shown in Figures 2 and 3, were converted into six-segment heat load profiles for the DHS using Formula (2). The results are presented in Table 3.

Table 3. The six-segment 4 h heat load profiles for a typical day of the season.

Time Segment	1	2	3	4	5	6
Day of the heating season	0.928	0.926	0.939	0.939	0.955	0.992
Day of the non-heating season	0.034	0.243	0.305	0.224	0.287	0.458

The resulting forecast structure of IPS capacities, obtained from an optimisation calculation based on the criterion of minimising system-wide costs whilst meeting the ELSs and TLSs, is presented in Table 4.

Table 4. Projected IPS capacity structure up to 2040, GW.

Capacities	2030	2035	2040
Total capacity, GW	39.1	44.4	51.0
NPPs	8.9	12.0	14.0
TPPs and CHPs(coal-fired)	4.5	2.2	0.0
TPPs and CHPs (gas-fired)	3.0	2.1	2.1
Gas-powered cogeneration units	4.0	4.0	5.3
TPSs (biomass)	0.5	0.7	0.9
WPPs	2.3	4.5	6.5
SPPs	9.1	11.6	14.9
HPPs and PSHPs	6.0	6.2	6.2
BESSs	0.8	1.0	1.1
EHGs consumption capacity	1.0	1.4	2.0

The operation of energy storage systems, pumped storage power stations, cogeneration units and electric boilers is illustrated by the results of modelling the coverage of heating and electricity demand for typical days in the heating and non-heating seasons of 2040 in Tables 5 and 6.

Table 5. Load coverage balances for a typical day in the 2040 heating season.

Load Segments	1	2	3	4	5	6
<i>Capacities</i>	<i>Electrical load, MW</i>					
NPPs	13,338	13,338	13,338	13,338	13,338	13,338
TPPs (existing)	1500	1667	1667	1667	1667	1667
TPPs (highly manoeuvrable)	0	91	0	0	611	103
TPPs (bio)	771	827	827	827	827	827
SPPs	0	146	2188	1726	0	0
WPPs	3233	3117	2786	2703	3432	4062

Table 5. Cont.

Load Segments	1	2	3	4	5	6
HPPs	100	100	427	1499	2774	100
PSHPs (generation)	0	0	1218	0	0	0
PSHPs pumping	−1625	0	0	0	0	0
EHGs (consumption)	0	0	0	0	0	0
Load	17,318	19,286	22,451	21,759	22,649	20,097
Capacities	Heat load, MW					
Gas boilers	3851	3762	3996	3900	3353	4302
EHGs	0	0	0	0	0	0
Biomass boilers	980	980	980	980	980	980
CHPPs (gas)	2053	2377	2281	2281	2924	2390
CHPPs (biomass)	856	897	897	897	897	897
Load	7740	8016	8154	8058	8154	8569

Table 6. Load coverage balances for a typical day in the 2040 non-heating season.

Load Segments	1	2	3	4	5	6
Capacities	Electrical load, MW					
NPPs	9521	9521	9552	8922	9552	9521
TPPs (existing)	170	189	189	189	189	189
TPPs (highly manoeuvrable)	0	0	0	0	0	974
TPPs (bio)	243	243	256	243	256	243
SPPs	0	1137	7756	7626	2239	0
WPPs	1697	1423	524	1581	2424	2056
HPPs	832	1137	75	477	865	2016
PSHPs (generation)	0	0	0	0	0	1153
BESSs (discharge)	0	0	0	0	300	0
PSHPs (pumping)	0	0	0	−1538	0	0
BESSs (charge)	0	0	−330	0	0	0
EHGs (consumption)	0	0	−2000	−982	0	0
Load	12,462	13,649	16,022	16,517	15,825	16,151
Capacities	Heat load, MW					
Gas boilers	0	1263	0	0	422	1513
EHGs	0	0	1900	933	0	0
Biomass boilers	95	300	300	300	300	300
CHPPs (gas)	74	819	377	374	819	1952
CHPPs (biomass)	38	382	39	38	394	382
Load	207	2764	2616	1645	1935	4146

In Tables 5 and 6, all values are given in MW; negative values indicate consumption powers in the load-coverage balances. All powers are considered constant for each segment of the daily load schedule.

The results of the daily power balancing, shown in Tables 5 and 6, indicate that PtH-technology electric boilers are used only during the non-heating season, at times of day

when SPPs generate significant amounts of electricity; the powers of these plants, combined with that of WPPs, account for almost half of the load capacity. At the same time, more than half of the load demand is covered by inflexible NPPs. This necessitates the use of electric boilers to consume the surplus of these VRES, with heat being supplied to DHS, thereby displacing natural gas-fired technologies from in TLS coverage. The reduction in thermal load during the middle of the day leads to a decrease in the use of electric boilers in ELS coverage, with PSHPs being utilised to meet electricity demand. On a typical day during the heating season, NPPs power accounts for more than half of electrical power consumption, which leads to the PSHP use in traditional consumption mode during nighttime load dips, with subsequent electricity supply during periods of peak demand.

To compare the advantages of using PtH technology, a model calculation was performed in which the capacities of the electric boilers were not considered, and the storage systems' capacities were set to match the values obtained in the previous model calculation. The results for covering the electrical and thermal loads on a typical day of the heating season were almost identical to those from the preliminary calculation. In a typical day during the non-heating season, storage systems operate at maximum power to cover the segments of the daily electricity load schedule (Table 7). However, the total energy storage capacity of energy storage systems remains insufficient to achieve balance, and during periods of peak solar power generation, their output is limited. In addition, the lack of heat output from electric boilers has led to an increased use of natural gas-fired capacity (at CHP plants and boiler houses). Their increased heat production over the course of a day—by 8.6 thousand MWh—led to a 2.8 thousand metric ton increase in CO₂ emissions per day.

Table 7. Load coverage balances for a typical day in the 2040 non-heating season without electrical boilers.

Load Segments	1	2	3	4	5	6
<i>Capacities</i>	<i>Electrical load, MW</i>					
NPPs	9312	9312	9344	8714	9344	9312
TPPs (existing)	189	189	189	189	189	189
TPPs (highly manoeuvrable)	0	0	0	0	0	963
TPPs (bio)	243	243	256	243	256	243
SPPs	0	1137	7756	7626	2239	0
WPPs	1697	1423	854	1581	2424	2056
HPPs	1021	1346	75	75	1373	1110
PSHPs (generation)	0	0	0	0	0	1191
BESS (discharge)	0	0	0	0	0	1088
PSHPs (pumping)	0	0	−1588	0	0	0
BESSs (charge)	0	0	0	−1160	0	0
Load	12,462	13,649	16,022	16,517	15,825	16,151
RES curtailment	0	0	−863	−750	0	0
<i>Capacities</i>	<i>Heat load, MW</i>					
Gas boilers	0	1263	1103	144	422	1512
Biomass boilers	87	300	300	300	300	300
CHPPs (gas)	82	819	819	819	819	1952
CHPPs (biomass)	38	382	394	382	394	382
Load	207	2764	2616	1645	1935	4146

The test modelling results demonstrated the feasibility of using PtH technology as an added source of power system flexibility when integrating a significant amount of renewable energy sources, by converting their excess generation into thermal energy, which is then supplied to the district heating system. The lower time resolution of the daily load curves used in long-term period modelling does not allow for full consideration of short-term changes in renewable energy generation and consumption, which requires an additional assessment of whether the resulting power system forecast capacity structures are adequate to balance such changes. The further modelling involves using the developed UC model for Ukraine's power system to stage-by-stage verify and adjust the adequacy of the obtained long-term power capacity structures to meet daily load schedules throughout the year.

The resulting power system capacity structure is the output of a test calculation based on a single illustrative scenario of external conditions for the development of electricity and heat supply systems and does not constitute a final forecast. Determining the long-term development paths for the Ukraine power system's capacity structure requires both the development of scenarios for the external conditions of its operation and development (scenarios of projected demand for electricity and thermal energy, fuel prices and environmental charges, changes in the regulatory and legal framework governing the operation and development of both the power system as a whole and individual technologies, etc.), as well as the extension of the model itself through the simulation of balances and conditions for meeting load schedules on other typical days.

4. Conclusions

It has been shown that integrating large-scale SPPs and WPPs with poorly predictable stochastic electricity output places stringent demands on the power system's flexibility. When this flexibility is insufficient, operators resort to forced curtailment of their power, leading to economic losses and a reduction in the expected level of greenhouse gas emission reductions.

It has been established that the key measures to avoid curtailment are the development of energy storage, the expansion of interregional interconnectors, demand response and the optimisation of the capacity mix. Forced curtailment of RES can be prevented through synergy between the electricity and heating sectors using PtH technology. The use of renewable electricity for heating purposes can help decarbonise the heating sector and facilitate the integration of VRES into the power system, providing additional flexibility. PtH systems can utilise surplus electricity from VRES to meet heating needs, thereby avoiding the curtailment of VRES generation and contributing to the decarbonisation of the electricity and district heating sectors.

The development of a long-term forecasting model for the evolution of the power system's capacity structure, combining the balances of coverage of the electrical load of the power system and the thermal load of the district heating system for typical days of the year, ensured the consideration of energy storage systems and PtH technology for the consumption of surplus energy from SPPs and WPPs.

The results of testing the model using forecasts of electricity demand in Ukraine's IPS and heat consumption by DHS up to 2040, covering typical daily electrical and heat load profiles consisting of six four-hour segments, demonstrated the feasibility of using PtH electric boilers during the non-heating season when there is significant renewable energy generation, particularly solar generation, and the significant baseload power of NPPs. The use of EHG to consume surplus energy from these renewables by supplying heat to DHS, thereby replacing heat from natural gas-fired technologies, contributes to the decarbonisation of both the electricity and heat supply. Without the use of PtH-technology

electric boilers, the available capacity of storage systems proved insufficient to cover a typical daily electricity load profile and balance electricity production and consumption; as a result, a significant share of renewable energy generation was restricted during peak solar power plant generation periods.

An 8.6 thousand MWh increase in heat production by natural gas-fired CHP plants and boiler houses over a 24 h period, with no heat supplied by electric boilers, led to a 2.8 thousand ton increase in CO₂ emissions per day.

Author Contributions: Conceptualization, T.N., V.D. (Volodymyr Derii) and A.Z.; methodology, T.N., V.D. (Volodymyr Derii) and A.Z.; software, T.N. and V.D. (Volodymyr Derii); validation, V.D. (Volodymyr Derii) and V.D. (Viktor Denysov); formal analysis, V.D. (Volodymyr Derii) and V.D. (Viktor Denysov); investigation, T.N., V.D. (Volodymyr Derii) and A.Z.; resources, A.Z. and V.D. (Viktor Denysov); data curation, V.D. (Volodymyr Derii) and A.Z.; writing—original draft preparation, T.N., V.D. (Volodymyr Derii) and A.Z.; writing—review and editing, A.Z. and V.D. (Viktor Denysov); visualisation, T.N.; supervision, T.N. and V.D. (Volodymyr Derii); project administration, T.N. and A.Z.; funding acquisition, A.Z. and V.D. (Viktor Denysov). All authors have read and agreed to the published version of the manuscript.

Funding: This research received no external funding.

Data Availability Statement: The data presented in this study are available on request from the corresponding author due to special restrictions on access to data regarding the functioning of critical infrastructure.

Acknowledgments: This work was supported by projects “Integrated modeling for robust management of food-energy-water-social-environmental (FEWSE) nexus security and sustainable development” (IIASA-NASU, 22-501 (R-45-T)), “Comprehensive analysis of robust preventive and adaptive measures of food, energy, water and social management in the context of systemic risks and consequences of COVID-19” (0122U000552, 2022–2026), “Development of the structure and ensuring the functioning of self-sufficient distributed generation” (0125U001572, 2025–2026), and “Improving the hierarchical system of mathematical and software-information tools for research on the development directions of integrated power systems in the transition to a low-carbon economy” (0122U000236, 2022–2026).

Conflicts of Interest: The authors declare no conflicts of interest.

Abbreviations

The following abbreviations are used in this manuscript:

BESS	Battery energy storage system
CF	Capacity factor
CHPP	Combined heat and power plant
DHS	District heating system
ELS	Electricity load schedule
ENTSO-E	European Network of Transmission System Operators for Electricity
EHG	Electric heat generator
EU	European Union
HPS	Hydroelectric power stations
IEA	International Energy Agency
IPS	Integrated power system
GHGs	Greenhouse gases
NECP	National Energy and Climate Plan
NEURC	National Energy and Utilities Regulatory Commission of Ukraine
NPP	Nuclear power plant
PSHP	Pumped-storage hydroelectric plant

PtH	Power-to-Heat
RES	Renewable energy sources
SPP	Solar power plant
TLS	Thermal load schedules
TPP	Thermal power plant
VRES	Variable renewable energy sources
WPP	Wind power plant

References

1. Ejub Che, E.; Roland Abeng, K.; Iweh, C.D.; Tsekouras, G.J.; Fopah-Lele, A. The Impact of Integrating Variable Renewable Energy Sources into Grid-Connected Power Systems: Challenges, Mitigation Strategies, and Prospects. *Energies* **2025**, *18*, 689. [\[CrossRef\]](#)
2. IEA. *Integrating Solar and Wind, Global Experience and Emerging Challenges*; IEA: Paris, France, 2024. Available online: <https://www.iea.org/reports/integrating-solar-and-wind> (accessed on 17 May 2026).
3. Global Power System Transformation Consortium. *What Is Power System Curtailment?* National Renewable Energy Laboratory: Golden, CO, USA, 2024.
4. Bird, L.; Cochran, J.; Wang, X. *Wind and Solar Energy Curtailment: A Review of International Experience*; Technical Report NREL/TP-6A20-60983; National Renewable Energy Laboratory (NREL): Golden, CO, USA, 2014.
5. Denholm, P.; Mai, T. *Timescales of Energy Storage Needed for Reducing Renewable Energy Curtailment*; Technical Report NREL/TP-6A20-68960; National Renewable Energy Laboratory (NREL): Golden, CO, USA, 2017. Available online: <https://docs.nrel.gov/docs/fy17osti/68960.pdf> (accessed on 17 May 2026).
6. Bunodiare, A.; Lee, H.S. Renewable Energy Curtailment: Prediction Using a Logic-Based Forecasting Method and Mitigation Measures in Kyushu, Japan. *Energies* **2020**, *13*, 4703. [\[CrossRef\]](#)
7. Brown, T.; Schlachtberger, D.; Kies, A.; Schramm, S.; Greiner, M. Synergies of sector coupling and transmission reinforcement in a cost-optimised, highly renewable European energy system. *Energy* **2018**, *160*, 720–739. [\[CrossRef\]](#)
8. Bloess, A.; Schill, W.-P.; Zerrahn, A. Power-to-heat for renewable energy integration: A review of technologies, modelling approaches, and flexibility potentials. *Appl. Energy* **2018**, *212*, 1611–1626. [\[CrossRef\]](#)
9. Babak, V.; Kulyk, M. Increasing the Efficiency and Security of Integrated Power System Operation Through Heat Supply Electrification in Ukraine. *Sci. Innov.* **2023**, *19*, 100–116. [\[CrossRef\]](#)
10. Sornek, K.; Homa, M.; Frigura-Iliasa, F.M.; Frigura-Iliasa, M.; Jankowski, M.; Papis-Frączek, K.; Katerla, J.; Janus, J. Power-to-Heat and Seasonal Thermal Energy Storage: Pathways Toward a Low-Carbon Future for District Heating. *Energies* **2025**, *18*, 5577. [\[CrossRef\]](#)
11. Freischlad, B.; Yang, C.-L.; Engelter, A.; Vossel, C.; Reissner, F.; Steinke, F.; Niessen, S. Harnessing the flexibility of power-to-heat operation in building and district heating to support electricity systems: A review. *Adv. Appl. Energy* **2026**, *22*, 100272. [\[CrossRef\]](#)
12. IRENA. *Innovation Landscape Brief: Renewable Power-to-Heat*; International Renewable Energy Agency: Abu Dhabi, United Arab Emirates, 2019.
13. Arabzadeh, V.; Pilpola, S.; Lund, P.D. Coupling Variable Renewable Electricity Production to the Heating Sector through Curtailment and Power-to-heat Strategies for Accelerated Emission Reduction. *Future Cities Environ.* **2019**, *5*, 1. [\[CrossRef\]](#)
14. Khalili, S.; Lopez, G.; Breyer, C. The role and trends of flexibility options in analyses of 100% renewable energy systems towards the Power-to-X Economy. *Renew. Sustain. Energy Rev.* **2025**, *212*, 115383. [\[CrossRef\]](#)
15. Connolly, D.; Lund, H.; Mathiesen, B.V.; Werner, S.; Möller, B.; Persson, U.; Nielsen, S. Heat Roadmap Europe: Combining district heating with heat savings to decarbonise the EU energy system. *Energy Policy* **2014**, *65*, 475–489. [\[CrossRef\]](#)
16. Pfenninger, S.; Keirstead, J. Renewables, nuclear, or fossil fuels? Scenarios for Great Britain's power system considering costs, emissions and energy security. *Appl. Energy* **2015**, *152*, 83–93. [\[CrossRef\]](#)
17. Schill, W.-P.; Zerrahn, A. Long-run power storage requirements for high shares of renewables: Results and sensitivities. *Renew. Sustain. Energy Rev.* **2018**, *83*, 156–171. [\[CrossRef\]](#)
18. Gils, H.C.; Gardian, H.; Kittel, M.; Schill, W.-P.; Murmann, A.; Launer, J.; Gaumnitz, F.; van Ouwerkerk, J.; Mikurda, J.; Torralba-Díaz, L. Model-related outcome differences in power system models with sector coupling—Quantification and drivers. *Renew. Sustain. Energy Rev.* **2022**, *159*, 112177. [\[CrossRef\]](#)
19. Nechaeva, T.P. Model and structure of the long-term development of power generation capacities in the power system, taking into account the dynamics of capacity commissioning and decommissioning and changes in their technical and economic indicators. *Syst. Res. Energy* **2018**, *3*, 5–9. [\[CrossRef\]](#)
20. Nechaeva, T.P. Accounting for the use of storage systems in a model for forecasting the long-term development of the power system. *Syst. Res. Energy* **2021**, *3*, 14–22. [\[CrossRef\]](#)

21. Nechaeva, T.P. Modelling the assurance of grid reliability under conditions of significant volumes of renewable generation. *Syst. Res. Energy* **2022**, *1–2*, 42–49. [CrossRef]
22. Ministry of Economy, Environment and Agriculture of Ukraine. Draft Resolution of the Cabinet of Ministers of Ukraine “On Amendments to the National Energy and Climate Plan for the Period up to 2030”. 27 January 2026. Available online: <https://me.gov.ua/Documents/Detail/ed16f0fe-1c3a-4342-9dca-baf77864b497> (accessed on 17 May 2026).
23. Cabinet of Ministers of Ukraine. On the Approval of the National Renewable Energy Action Plan for the Period up to 2030 and the Action Plan for Its Implementation; Order No. 761-r of 13 August 2024. Available online: <https://www.kmu.gov.ua/npas/pro-zatverdzhennia-natsionalnoho-planu-dii-z-vidnovliuvanoi-enerhetyky-na-p-a761> (accessed on 17 May 2026).
24. Cabinet of Ministers of Ukraine. On the Approval of the Forecast of Ukraine’s Economic and Social Development for 2026–2028; Verkhovna Rada of Ukraine, Resolution No. 946 of 6 August 2025; 2025. Available online: <https://zakon.rada.gov.ua/laws/show/946-2025-%D0%BF#Text> (accessed on 17 May 2026).
25. Interfax-Ukraine. RES Capacity in Ukraine Has Increased 300-Fold Recently—Head of Ukrenergo. 27 April 2026. Available online: <https://interfax.com.ua/news/economic/1162685.html> (accessed on 17 May 2026).
26. ExPro. RES Is No Longer a Technology of the Future: It Is the Foundation of Our Energy Independence Today. 14 April 2026. Available online: <https://expro.com.ua/statti/uze--ce-vje-ne-tehnologiya-maybutnogo-ce-fundament-nasho-energetichno-nezalejnost-sogodn> (accessed on 17 May 2026).
27. Derii, V. The limits of centralised heat supply regarding the use of electricity from renewable sources. *Syst. Res. Energy* **2025**, *1*, 29–39. [CrossRef]
28. Shaflik, V. *Modern Hot Water Supply Systems*; Taki Spravy: Kyiv, Ukraine, 2010; 316p.

Disclaimer/Publisher’s Note: The statements, opinions and data contained in all publications are solely those of the individual author(s) and contributor(s) and not of MDPI and/or the editor(s). MDPI and/or the editor(s) disclaim responsibility for any injury to people or property resulting from any ideas, methods, instructions or products referred to in the content.