

Received July 27, 2021, accepted August 15, 2021, date of publication August 18, 2021, date of current version August 27, 2021.

Digital Object Identifier 10.1109/ACCESS.2021.3105829

Harnessing the Flexibility of District Heating System for Integrating Extensive Share of Renewable Energy Sources in Energy Systems

ARSLAN AHMAD BASHIR¹, JUHA JOKISALO², JUHANI HELJO³, AMIR SAFDARIAN⁴, AND MATTI LEHTONEN¹

¹Department of Electrical Engineering and Automation, Aalto University, 02150 Espoo, Finland

²Department of Mechanical Engineering, Aalto University, 02150 Espoo, Finland

³Faculty of Built Environment, University of Tampere, 33100 Tampere, Finland

⁴VTT Technical Research Centre of Finland, 02044 Espoo, Finland

Corresponding author: Arslan Ahmad Bashir (arslan.bashir@aalto.fi)

This research was supported by Aalto University as part of the ‘Renewable Finland’ project organized by the ‘Academy of Finland’.

ABSTRACT Lately, the European Union has reinforced the targets set to cut back carbon emissions. The energy generation sector and particularly, the district heating (DH) system, is still prevailed by combustion of fossil fuels that heavily contributes to such emissions. This paper presents a system-based approach to study the coupling between electricity and DH sector for effective mitigation of emissions. A mixed integer linear programming framework is proposed that aims to exploit the flexibility of electricity cogeneration together with partial electrification of the DH system by investing in renewable technologies. The objective is to simultaneously minimize the investment cost and emissions. Both the electricity and DH load profiles are segregated into critical and flexible types. Comprehensive demand response (DR) framework of thermostatically controlled loads and electric vehicles is considered while preserving the chronology. The framework is applied to the Finnish energy system considering the generation mix. Results prove that coordinating the electricity cogeneration with renewable generation combined with partly shifting from DH to electrified heating has a great potential in reducing the emissions. For an average weather scenario under DR, the least-cost solution guarantees an annual emission reduction of 12.04% relative to the total emissions of Finland against the total investment of €13.24Bn in wind and solar power generation.

INDEX TERMS Base-load generation, carbon emissions, district heating, demand response, power to heat, two-capacity building model.

Indices and Sets

i, ab, AB Index of apartment building, index of building type, set of apartment buildings.
 l, L Index and set of geographical locations for renewable generation installations.
 m, M Index and set of electric vehicles.
 n, N Index and set of detached houses.
 $t, \Delta t, T$ Index of time step, time resolution and set of time steps.

Variables

C Annual cost
 D_t^e Total electricity demand in time step t
 E Annual carbon emissions

The associate editor coordinating the review of this manuscript and approving it for publication was Arash Asrari¹.

LL_t^e, LL_t^h Electrical and heat load curtailed in time step t .
 LG_t^e, LG_t^h Electrical and heat generation curtailed in time t .
 $P_t^{chp_city_e}$ Electricity cogeneration of CHP plants in time t .
 $P_t^{chp_city_h}$,
 P_t^{HB} District heat production of CHP plants and heat boilers in time step t .
 $P_{t,n}^{sh}, P_{t,n}^{ewh}$ Power consumed by space heating unit and water heater of house n in time step t .
 $P_{t,m}^{ev}$ Charging power of EV m in time step t .
 P_t^{hyd} Hydro power produced in time step t .
 $P_l^{pv,max}$,
 $P_l^{w,max}$ Capacity of solar power and wind power to be installed at location l .

$P_{t,l}^{pv}, P_{t,l}^w$	Solar power and wind power produced at location l in time step t .	r	Percentage of electricity demand to be satisfied by controllable generation.
$Q_{t,ab,i}^{sh}, Q_{t,ab,i}^{dhw}$	Power consumption of space heating unit and domestic hot water of apartment building i of type ab in time step t respectively.	R_1, R_2	Maximum capacity of CHP and heat boilers respectively.
SOC_t^{hyd}	State of charge of aggregated hydro storage in time step t .	R_l^w, R_l^{pv}	Capacity limitation of wind and solar power at location l respectively.
$SOC_{t,m}^{ev}$	State of charge of EV m in time step t .	$SOC_{min}^{hyd}, SOC_{max}^{hyd}$	Minimum and maximum permissible limits of aggregated hydro storage.
$T_{t,n}^a, \phi_{t,ab,i}^a$	Indoor temperature in detached house n and apartment building i in time step t .	S	Solar insolation.
$T_{t,n}^{dhw}, \phi_{t,ab,i}^{dhw}$	Temperature of domestic hot water in house n and apartment building i in time step t .	$T_{t,l}^e$	Outdoor temperature at location l in time step t .
$u_{t,n}^{sh}, y_{t,ab,i}^{sh}$	Binary variables for turning on and off space heating loads.	$T_{t,n}^{set,sh}, T_{t,n}^{set,dhw}$	Set points for space heating and hot water temperatures in house n and time t respectively.
ε_t	Spillage of hydro power at time t .	T^{ref}	Reference temperature of PV cell.
λ_t	Cost of demand response from detached houses and apartment buildings in time step t .	T^{in}	Temperature of incoming water.
$\delta_{t,ab,i}^e$	District heat demand converted to electrified heating of apartment building i in time step t .	V_n^{tank}	Volume of DHW tank of house n .
Parameters		$w_{t,l}, w^r, w^c$	Wind speed at location l in time step t , rated speed, cut-in speed of wind turbine.
a_1, a_2	Per unit investment price of wind and solar power respectively.	α, β	Parameters for hydro storage dead band at the end of optimization horizon $[0, 1]$.
b_1, b_2	Cost of curtailed load and generation respectively.	$v_{t,n}^{use}, \zeta_{t,ab,i}^{dhw}$	Volume of domestic hot water used in detached house n and apartment building i of type ab in time step t respectively.
C^a, C^m	Thermal capacitance of indoor air and building fabric respectively.	$\phi_{t,ab,i}^{set,sh}, \phi_{t,ab,i}^{set,dhw}$	Set points for space heating and hot water temperatures in building i of type ab in time step t .
$d_{t,m}^{ev}$	Distance travelled by an EV m in time step t .	$\sigma_1, \sigma_2, \sigma_3$	Specific emission factors.
DH_t^{sb}	District heat demand of service buildings in time t .	Ω, μ	Yearly interest rate and study horizon respectively.
D_t^{crit}	Critical electricity demand in time step t .	γ	Power to heat ratio for electricity cogeneration.
$G_{t,l}, G^{ref}$	Solar irradiance at location l in time t , Reference solar irradiation.	χ_t	Hydro inflows in time step t .
H^m, H^e, H^g, H^x, H^y	Heat conductance between indoor air and building fabric node, external air and indoor air node, indoor air and ground node, between HVAC air and indoor air node, external air and building fabric node points respectively.	$\kappa_{t,n}^a, \kappa_{t,n}^{dhw}$	Penalty factor for demand response of space heating and domestic hot water loads in a detached house n in time step t .
$I^{sc}, NOCT$	Short circuit current and normal operating cell temperature of PV module.	$\tau_{t,ab,i}^a, \tau_{t,ab,i}^{dhw}$	Penalty factor for demand response of space heating and domestic hot water loads in an apartment building i of type ab in time step t .
$P_t^{Nuc}, P_t^{chp_ind}$	Electricity generation of nuclear and industrial CHP plants in time step t respectively.	Γ_n, Π_n	Annual space heating and electric water heater demand of a house n respectively.
$P_{min}^{hyd}, P_{max}^{hyd}$	Minimum and maximum level of hydro power.	$\xi_{ab,i}, \omega_{ab,i}$	Annual space heating and domestic hot water demand of apartment building i of type ab respectively.
$P_n^{sh,max}, Q_{ab,i}^{sh,max}$	Maximum power of heating unit of house n and apartment building i of type ab respectively.	$\Delta^{sh}, \Delta^{dhw}$	Thermal comfort band for space heating and domestic hot water loads.
Q_t^{int}, Q_t^{sol}	Internal and solar heat gains for estimating space heating demand respectively.	α_m	Annual charging demand of EV m .
		η_T, η_c	Travel and charging efficiency of EV respectively.
		Υ	Proportion of dispatchable generation reserved for handling uncertainty of solar and wind power

I. INTRODUCTION

In recent times, policy makers have realized necessary actions in order to mitigate the adverse effects of climate change. The chief contributor to the climate change is the combustion of fossil fuels, which is heavily used in the energy generation sector, i.e., electricity, district heat (DH), transport and gas grids etc. Hence, de-carbonization of energy systems is a crucial objective towards the clean environment. In this context, the European Union (EU) has put forth climate and energy framework to reduce anthropogenic greenhouse gas (GHG) emissions, increase the energy efficiency and the share of renewables. The goal stipulates the reduction of GHG emissions by 40% relative to 1990 levels by the year 2030 and by at least 80% by the year 2050 [1]. The targets for renewables and energy efficiency were tightened in 2018. These targets now specify a minimum 32% share of renewable energy sources (RESs) in the entire EU and 32.5% reduction in energy consumption by 2030. Moreover, the Paris Agreement on climate change underlines to limit the global temperature rise below 2°C.

Hence, it is primarily due to such environmental concerns and energy policies that the RESs, particularly wind and solar, will likely constitute a major component of the future energy system. Due to the intermittent nature of RESs, their increased penetration in the energy system will change the role of conventional thermal power plants, i.e., from the primary source of electricity to flexibility provider [2]. Further, due to RESs, there will be a reduced need of constant base-load generation and increased need of flexible generation in the future [3].

As remarked earlier, the combustion of fossil fuels is prevalent in electricity, district heat (DH), transport and gas grids, however according to [4], the building stock in the Europe is responsible for consuming 40% of the generated energy. Further, district heat (DH) in buildings constitutes most of the heat energy and it is often fossil fuel based. Therefore, the de-carbonization objective of energy systems can be achieved by one or a combination of the following approaches:

- I. By renovating the older or existing building stock to higher standards [5]. This approach is also referred as heat savings or energy efficiency measures in the literature [6].
- II. By investing in the electricity grid, i.e., by replacing a high percentage of conventional generation with emission free renewable energy sources. Such an approach is commonly known as Smart Grid approach which, sometimes also focuses on limited cross-sectoral integration and control [7].
- III. The third approach paves the way to the concept of smart energy system which was introduced to identify and develop potential synergies between different sub-sectors in the energy system [8]. In simple words, the most effective solution can be obtained by integrating the electricity, thermal and gas grids, and storage technologies in the energy system, so that the

resulting solution is not only optimal for individual sub-sectors, but for the whole energy system as well. Most often, this approach is aimed at 100% renewable energy solution leading to huge investments in all grids, storage, and conversion technologies.

However, separate case studies are required to compare the economics of emission reductions for each of the three approaches.

The first approach, i.e., building renovations, is tailored to specific building type as different types of buildings, such as residential and commercial, have different energy consumption profiles. Studies on such energy retrofits have been extensively performed in the literature. For instance, the feasibility of nearly zero energy building retrofits from techno-socio perspectives was investigated in [9]. The energy retrofits on the European office buildings were studied in [10]. The authors in [5] performed a multi-objective optimization to achieve a balance between energy cost and carbon emissions by retrofitting the Finnish apartment buildings (ABs), classified according to build-year. The results of the study [5] demonstrated that the least cost solution would require a total investment of €11.4Bn for renovating the Finnish apartment buildings to achieve 3.4% emission reductions annually in a planning horizon of 25 years. Whereas, the Finnish building stock comprising houses was examined in [11] using the same approach. It was shown that a total investment of €38.61Bn in the least cost case would cut down country-wide carbon emissions by 12.24% annually. The studies [5], [11] also found that shifting from DH to electrified heating, i.e., P2H coupling, resulted in a maximum reduction of emissions. The resulting electrified heating may be based on heat pumps or electric boilers installed in dense urban DH systems or individual heat pumps in rural areas [6], [12]. In a subsequent study [13], the effect of such energy retrofits on peak demand was also analyzed. The work concluded that shifting to electrified heating on a large scale would significantly increase the electrical energy demand, which in turn introduces major changes in the overall energy generation mix. Since, the increased electricity demand would require the operation of more peaking thermal plants and it poses negative impact on emission benefits that are very sensitive to energy generation mix. Therefore, the emission reductions computed in [5], [11] were overestimated.

In view of above, building energy retrofits alone is not an effective solution for emission reduction, as it is expensive and unable to accomplish carbon-neutral system as it targets only the consumption side. The building retrofit approach aims to reduce the energy consumption of buildings, particularly heating demand. However, such energy retrofits and heat savings can play a significant role in 4th generation district heating (4GDH) systems [14]. The 4GDH system (or smart thermal grid) requires lowering of forward and return temperatures of heat source to provide heat to low energy buildings at low grid losses [15]. While the reduction in return temperatures is practically achievable in existing buildings,

lowering of forward temperature to 55°C is possible only when renovations take place. Further, heat conservation, which is a well-known feature of future 4GDH, enables low temperature DH which, in turn, increases the CoP of heat pumps and the efficiency of CHP units in the thermal grid. Yet, the biggest challenge in 4GDH lies in the expansion of the DH network and lowering the supply temperature to minimize network losses and increase recycling of heat. According to a study [16], switching from the current Scandinavian 3GDH to 4GDH itself requires an annuitized investment cost of up to 100M€ for a country size of Denmark.

Due to the above mentioned considerations, it is essential to create a synergy between electricity and other sub-sectors by considering the details of the whole energy generation mix [17] and simultaneously making investments in emission free energy sources. In such a system, it is possible to utilize the electricity generation of RESs in other sub-sectors [18]. This concept leads to the latter two approaches for emission reduction, as discussed earlier. Our current work overlaps with smart grid approach in that we plan the generation capacity and quantify the optimal investments related to RESs that are needed at the energy system level in order to mitigate carbon emissions, while the work also coincides with the smart energy systems approach, as the coupling between the future electricity, district heat and transport sub-sectors is studied. The primary reason to simultaneously consider both approaches is that it enables to study the existing electricity generation mix and the hourly balance of technology-wise powers throughout the horizon to mitigate carbon emissions in different sub-sectors.

Based on the building retrofit studies, it is clear that the future electricity demand in the Northern European countries will be heat dominated. As the demand grows, new generating plants are planned keeping in view the fixed and variable costs over long-term period. Hence, investing in RESs at system level is an environmentally friendly option, which is also in line with the EU targets.

Another cost-effective alternative to combat this issue of demand growth is unleashing demand response (DR). DR is an auspicious complement to RESs' variability [19]. It prevents the operation of expensive and high emission generators, defers network reinforcements as well as creates a more reliable system by contributing to reserve margin. A variety of DR approaches have been widely analyzed in the literature and majority of them lead to the mutual benefit for the power utility and the end user [20]. Among all the DR loads, thermostatically controlled loads (TCLs) secure a prominent niche [21]. TCLs mainly include heating, ventilation and air-conditioning (HVAC), refrigerator, and electric water heater (EWH) etc.

The user comfort, in case of TCLs, is directly linked to their set point temperature; the associated DR costs depend on the deviation from this set point temperature within the defined thermal comfort band. However, in case of other appliances, it is relatively difficult to establish the acceptable limits of user comfort [22]. For instance, the load shifting costs linked

to the Finnish household appliances were estimated in [23] by applying customer survey based approach. Moreover, no additional equipment other than a smart thermostat is required to probe the power resource or sink capabilities of TCLs. Additionally, HVAC load coordinated with building thermal dynamics enable to effectively accommodate the volatile nature of RESs and hence well-insulated buildings act as a small storage buffer [24], [25]. Similarly, EWH is another promising candidate of DR and it has a vital role in detached houses for domestic hot water (DHW) consumption [26]. A partial thermal storage is usually required for EWH operation, while in some cases, it may also be integrated with the HVAC unit to economically satisfy the space heating demand [27].

The scenario pathway to achieve the EU-2050 targets urgently requires the optimization of new RESs investments in the current energy system. This problem relates to generation expansion planning (GEP) in which the objective is to meet the future load duration curve at minimum cost. Moreover, DR tool, when combined with the GEP, aids to minimize the cost. Many GEP models aiming at different system configurations have been presented in the literature. However, there is no one-size-fits-all approach to the GEP problem, therefore the existing models differ with respect to the details associated with temporal and spatial resolution, DR strategies, operation decisions and the study period. Due to the storage devices and RESs, such as wind and solar power, it is very important to preserve the chronology and natural correlations among, for instance, load, solar irradiation and wind speed [28]. In this research field, the work [29] followed time slice representation in the proposed GEP model. In this representation, a year is divided into a number of periods, such as seasons, weekdays, weekends, day and night times etc. This method retains some of the chronology. An alternative method adopted in [30] is to choose representative periods like set of days or weeks per year. The best approach to retain full chronology is to use full hourly or sub-hourly resolution over a medium or long term period as accomplished in [31]. Besides typical GEP formulations, open source models like Balmorel [32] also studies planning and operation decisions while taking into account the chronological aspects and operational constraints of generation units.

The GEP formulations employing time slice or clustering approach are unable to incorporate an adequate framework for load modelling and corresponding DR, since it requires preserving maximum chronology. For instance, the study [29] limited the DR by maximum amount of shift-able loads inside the assumed load block computed from load duration curve, without considering the details of the loads. The work [33] proposed a comprehensive bi-level planning problem to model the concurrent interactions between the prosumers and the wholesale market in an integrated community energy system, but neglected load modelling completely. Similarly, the work [34] planned the optimal capacity of

community energy storage units against an average daily load factor in a radial distribution network that was populated with distributed PVs. The contribution [35] performed the joint multi-stage expansion of distributed generation and distribution network by considering only three load levels from load duration curve. The GEP model in [36] optimized the total investment in new generation mix by approximating a full season with a mere 24-h period and assuming fixed demand profile. Likewise, in an attempt to avoid intractability, the investment planning models formulated in [37]–[39] completely disregarded the demand details and DR mechanism. However, the uncertainty and the correlations among input parameters were respected by assuming a finite number of levels within few blocks derived from the corresponding load duration curves. The study [40] devised a comprehensive generation and expansion planning tool inside a market mechanism but the demand was modelled simply by approximating the load duration curve to a few levels.

Hence, the so-called clustering of the input data has a negative impact on the chronology that is essential for load modelling and assessing the potential of flexibility mechanisms. Further, the planned generation capacity should be robust to the inter-annual variability of RESs. This implies that the studies on GEP must not rely on weather data of a single year [41].

According to the presented literature review on investment planning, there has been extensive research on clustering based stochastic, multi-period investment approaches in electrical networks. However, the literature falls short in having DR focused and spatially diversified RESs deployment generation planning methods. Some of the above-referred expansion planning studies have long horizon but they were focused on weather data of a single year, which may lead to operational inadequacy if additional flexibility options are not considered [41]. The synergies between the electricity and heat sub-sectors are also neglected for estimating emission reduction potential in the energy sector, except for [42] where the capability of power to gas and power to fuel conversion plants was exploited in order to integrate a large share of RESs for the case of the Northern Europe.

On the other hand, space-heating loads in the Nordic countries offer a great DR potential. According to a study [43], households' heating flexibility potential alone in the Northern Europe totals 22.8% of their total energy demand. In Finland only, the energy used for direct electric heating (DEH) in residential sector in year 2017 amounted to 11TWh, which covers nearly 12.5% of the total Finnish electricity consumption [44]. The reason of this high heating demand being the long winter season. Unleashing such DR can enable the efficient integration of RESs. From the supply side, it is anticipated that combined heat and power (CHP) plants and RESs in coordination with bulk energy storages could be used to satisfy the peak demand in the future energy systems [45]. In other words, the existing DH system may act as a buffer to integrate high penetrations of RESs [46].

This paper addresses the above-mentioned research gaps by proposing a planning-based formulation that jointly minimizes the RESs investment cost and the carbon emissions arising from energy generation while considering DH flexibility, electrification of heating system and comprehensive residential DR framework. We study the case of Finnish generation structure in year 2017 and our approach is based on central control of flexible loads in detached houses and apartment buildings (ABs), which is a well-known feature of the smart grid. It is assumed that households and the aggregator are already mutually agreed about a thermal comfort band within which the aggregator is authorized to alter the temperature and hence the corresponding electricity consumption [47], [48]. It is worthwhile to note that the incentive offered to the households for DR participation is outside the scope of this study. The main contributions of this work are summarized as under:

- Proposing an optimization solution that jointly minimizes the RESs investment cost and carbon emissions originating from the energy sector. The decision trajectory would be valuable for the policy makers to achieve the long-term targets of the EU climate and energy framework.
- The proposed model is a mixed integer linear programming model which is simulated using realistic data for the Finnish case study to anticipate the potential situation in the future.
- Numerous studies have been proposed in the literature that are either aimed at investing in building energy retrofits to achieve carbon emission reductions or target 100% renewable solutions using smart energy system approach. A shortcoming of the latter approach is that the existing electricity generation structure (including base-load, flexible hydro and CHP) is disregarded and replaced with new wind or other variable renewable energy source, as done in the Danish study [7], and the Finnish study [46]. In practice, the electricity system is unable to operate without a pre-defined proportion of flexible conventional generation to counter disturbances and the intermittency of RESs in real time. Moreover, the results of the above-mentioned studies were mainly dependent on a single time series of RESs generation. However, to the best of the authors' knowledge, no such study exists that seeks optimal solution by combining the smart grid approach and smart energy systems approach. The state-of-the-art of the current work is that the solution to integrate new capacity of fluctuating RESs is found within the cross-sectoral integration of electricity, heat, and transport sub-sectors by considering the hourly mix of the existing and new electricity generation as well as harnessing the flexibility of DH generation plants. There is a great need to determine the cost-effectiveness of this investment option. The results from our study can therefore enable the policy makers to compare the economics of investment alternatives

and make efficient decisions in mitigating emissions accordingly.

- Full chronology is preserved by simulating the problem for a one-year period with hourly resolution. It enables to implement the time linking constraints, such as aggregated hydro-generation ramping limits, tracking of inter-hour hydro-storage dynamics, and the end-user thermal comfort levels for space heating load. Comprehensive load models are utilized, for instance, two-capacity building model is employed to assess the space heating demand. DR is unleashed from the residential loads that mainly include space heating coordinated with building thermal inertia, DHW consumption and electric vehicles (EVs).
- 12 widely distributed geographical locations for solar and wind power installations have been simultaneously considered in our model. Each location has its own solar irradiance and wind speed profile simulated at 50m height [50]. Greater spatial diversity allows sites with good weather profiles to be chosen, resulting in lower investment costs. Although the proposed model is deterministic, it is tested using different wind speed and solar irradiance time series, one at a time, for each of the 12 targeted locations. Therefore, the uncertainty, geographical diversification and inter-annual weather variability have been incorporated.

II. FLEXIBLE LOADS

A. ELECTRIC VEHICLE CHARGING

Modelling the EV charging schedule involves the driving behavior and respective trip lengths in Monte Carlo simulation. The ‘Finnish National Travel Survey’ provides the requisite data, which includes the starting time probabilities of journeys in respect of different age groups, number of trips and the corresponding trip lengths for different weekdays [51]. Such a probability distribution represents an average daily scenario that accounts for all seasons including the holiday periods of a year. Therefore, the considered trips are not merely limited to work, but also include trips for education, business, shopping, recreation, sports, escorting and personal business etc. as given in [51]. Different EV profiles can be simulated utilizing this data. Moreover, if the travel efficiency and the battery capacity are known, the travel pattern of an EV can be transformed into electricity consumption accordingly.

A weekday is considered in this work provided the people commute to working and public places as described above. Since, at the moment, the EV technology is in evolving stage, it is fair to assume that the charging locations are available only at homes and the EV is plugged in as soon as it reaches its parking slot for the business as usual (BAU) case. Alternatively, when DR is activated, the charging schedule of EV can be deferred until the battery has enough capacity to satisfy the demand of the following journey. It is possible if the EV driver conveys its trip schedule to the

aggregator for the following day. Only grid to vehicle mode is studied.

B. DIRECT ELECTRIC SPACE HEATING LOADS

Direct electric heating (DEH) requires a thermostatically controlled heating component. The electricity drawn from the grid is directly converted into heat energy whenever indoor ambient temperature inside a building falls below the set point temperature. Contrarily, heating is switched off when indoor temperature exceeds the set point. Although single thermostat operation is non-linear, the corresponding sum of loads in a building can be linearly modelled with sufficient accuracy. In this work, the heating or cooling demand and the associated flexibility of a detached house and apartment building are represented by two-capacity building model (Please see equations (18)-(19)). The model has two unknown temperatures, namely the indoor and the building fabric temperatures, controlled by power consumption of HVAC unit. The details are given in our previous work [21]. The unknown building parameters are determined using dynamic building energy simulation tool IDA-ICE. To do so, the heating power of the studied building was interrupted for 6 hours and the variance between the response obtained from IDA-ICE and derived two-capacity model were then minimized to identify the unknown parameters. The calibration was carried out using three different outdoor temperatures, i.e., $+10^{\circ}\text{C}$, 0°C and -10°C . The procedure is shown in Figure 1.

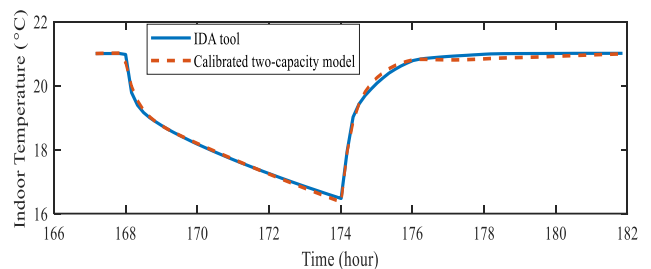


FIGURE 1. Calibration of two-capacity building model: Evolution of indoor temperature (outdoor temperature 0°C).

In this work, the parameters have been calibrated separately for detached houses and various types of AB. Each house is a new medium weight, 2-floor single-family house, which follows the Finnish guidelines for Passive houses. The house was defined in more detail in [52]. Four age classes of ABs i.e., AB1, AB2, AB3, AB4 are studied that were classified according to the building code in effect at the time of their construction; with AB1 built before 1976, AB2 built during 1976-2002, AB3 built between 2003-2009, and AB4 built from 2010 onwards. The building code turned stringent with time. These ABs also differ in the U-values of the envelope, ventilation type, window areas etc. AB3 and AB4 buildings have built-in heat recovery system. The detached houses and ABs are assumed to have smart thermostats capable of receiving signals from the aggregator.

III. OPTIMIZATION FORMULATION

This section proposes the optimization framework to obtain the optimal decision Pareto front. The objective is the simultaneous minimization of cost and carbon emissions, each tunable with a weighting coefficient $w \in (0, 1]$ as given in (1).

Minimize

$$z = w.C + (1 - w).E \quad (1)$$

$$C = \frac{\Omega}{1 - 1/(1 + \Omega)^\mu} (a_1 \sum_l P_l^{w,\max} + a_2 \sum_l P_l^{pv,\max}) + \sum_t (b_1(LL_t^e + LL_t^h) + b_2(LG_t^e + LG_t^h) + \lambda_t) \Delta t \quad (2)$$

$$E = \sum_t (\sigma_1 P_t^{chp_city_e} + \sigma_2 P_t^{chp_city_h} + \sigma_3 P_t^{HB}) \Delta t \quad (3)$$

The first part in (1) i.e., cost function expanded in (2), is related to the annuitized investment costs in solar and wind power generation aggregated over all locations. The crucial operational details such as the cost of energy curtailments and DR are incorporated

The second part in (1) expanded in (3) concerns the specific carbon emissions arising from DH and the electricity co-generation. These emissions are based on the yearly moving average emission factor (kg CO₂/MWh). Existing condensing thermal power capacity is not included in the generation structure with the aim to mitigate emissions at the cost of RESs. The objective function (1) is subject to the following constraints:

$$P_{t,l}^w = \begin{cases} \frac{P_l^{w,\max}}{w^r - w^c} (w_{t,l} - w^c), & w^c \leq w_{t,l} \leq w^r \\ P_l^{w,\max}, & w_{t,l} \geq w^r \\ 0, & w_{t,l} \leq w^c, \quad \forall t \in T, \forall l \in L \end{cases} \quad (4)$$

$$P_{t,l}^{pv} = P_l^{pv,\max} \frac{G_{t,l}}{G^{ref}} \cdot \frac{\ln(I^{sc})}{\ln(I^{sc} G^{ref} / G_{t,l})} \cdot \left(\frac{T^{ref}}{T_{t,l}^e + \frac{NOCT-20}{80} S} \right), \quad \forall t \in T, \forall l \in L \quad (5)$$

$$P_l^{w,\max} \leq R_l^w, \quad \forall l \in L \quad (6)$$

$$P_l^{pv,\max} \leq R_l^{pv}, \quad \forall l \in L \quad (7)$$

$$P_t^{Nuc} + P_t^{chp_ind} + P_t^{chp_city_e} + P_t^{hyd} + \sum_l P_{t,l}^w + \sum_l P_{t,l}^{pv} - LG_t^e = D_t^e - LL_t^e, \quad \forall t \in T \quad (8)$$

$$P_t^{chp_city_e} = \gamma \cdot P_t^{chp_city_h}, \quad \forall t \in T \quad (9)$$

$$P_t^{chp_city_e}, P_t^{HB} \leq R_1, R_2, \quad \forall t \in T \quad (10)$$

$$SOC_t^{hyd} = SOC_{t-1}^{hyd} + \chi_t \Delta t - P_t^{hyd} \Delta t - \varepsilon_t \Delta t, \quad \forall t \in T \quad (11)$$

$$P_{\min}^{hyd} \leq P_t^{hyd} \leq P_{\max}^{hyd} \quad (12)$$

$$SOC_{\min}^{hyd} \leq SOC_t^{hyd} \leq SOC_{\max}^{hyd} \quad (13)$$

$$\alpha \cdot SOC_{\max}^{hyd} \leq SOC_{t=end}^{hyd} \leq \beta \cdot SOC_{\max}^{hyd} \quad (14)$$

$$r \cdot D_t^e \leq P_t^{hyd} + P_t^{chp_city_e} \leq (1 - \Upsilon) (P_{\max}^{hyd} + R_1), \quad \forall t \in T \quad (15)$$

$$(P_t^{chp_city_h} + P_t^{HB} - LG_t^h) + \sum_{ab} \sum_i \delta_{t,ab,i}^e = \sum_{ab} \sum_i (Q_{t,ab,i}^{sh} + Q_{t,ab,i}^{dhw}) + DH_t^{sb} - LL_t^h \quad (16)$$

$$D_t^e = \sum_n P_{t,n}^{sh} + \sum_n P_{t,n}^{ewh} + \sum_m P_{t,m}^{ev} + D_t^{crit} + \sum_{ab} \sum_i \delta_{t,ab,i}^e, \quad \forall t \in T, \forall n \in N, \forall m \in M \quad (17)$$

$$T_t^a = \frac{T_{t-1}^a + \frac{\Delta t}{C_a} (H^m T_{t-1}^m + H^e T_t^e + H^s T_t^s + H^x T_t^x + Q_{t,ab,i}^{int} + Q_{t,ab,i}^{sol} + P_t^{sh})}{1 + \frac{\Delta t}{C_a} (H^m + H^e + H^s + H^x)}, \quad \forall t \in T, \quad \forall n \in N, \forall i, ab \in AB \quad (18)$$

$$T_t^m = \frac{T_{t-1}^m + \frac{\Delta t}{C_m} (H^m T_t^a + H^y T_t^e)}{1 + \frac{\Delta t}{C_m} (H^m + H^y)}, \quad \forall t \in T, \quad \forall n \in N, \forall i, ab \in AB \quad (19)$$

$$T_{t,n}^{set,sh} - \frac{\Delta^{sh}}{2} \leq T_{t,n}^a \leq T_{t,n}^{set,sh} + \frac{\Delta^{sh}}{2} + u_{t,n}^{sh} M, \quad \forall t \in T, n \in N \quad (20)$$

$$\phi_{t,ab,i}^{set,sh} - \frac{\Delta^{sh}}{2} \leq \phi_{t,ab,i}^a \leq \phi_{t,ab,i}^{set,sh} + \frac{\Delta^{sh}}{2} + y_{t,ab,i}^{sh} M, \quad \forall t \in T, \forall i, ab \in AB \quad (21)$$

$$P_{t,n}^{sh} \leq P_n^{sh,\max} (1 - u_{t,n}^{sh}), \quad \forall t \in T, \forall n \in N \quad (22)$$

$$Q_{t,ab,i}^{sh} \leq Q_{ab,i}^{sh,\max} (1 - y_{t,ab,i}^{sh}), \quad \forall t \in T, \forall i, ab \in AB \quad (23)$$

$$T_{t,n}^{dhw} = \frac{T_{t-1,n}^{dhw} (V_n^{\tan k} - v_{t,n}^{use})}{V_n^{\tan k}} + \frac{T_{t,n}^{in,use}}{V_n^{\tan k}} + \frac{P_{t,n}^{ewh}}{1.1628 V_n^{\tan k}}, \quad \forall t \in T, n \in N \quad (24)$$

$$T_{t,n}^{set,dhw} - \frac{\Delta^{dhw}}{2} \leq T_{t,n}^{dhw} \leq T_{t,n}^{set,dhw} + \frac{\Delta^{dhw}}{2}, \quad \forall t \in T, n \in N \quad (25)$$

$$Q_{t,ab,i}^{dhw} = 1.1628 \zeta_{t,ab,i}^{dhw} (\phi_{t,ab,i}^{dhw} - T^{in}), \quad \forall t \in T, \quad \forall i, ab \in AB \quad (26)$$

$$\phi_{t,ab,i}^{set,dhw} - \frac{\Delta^{dhw}}{2} \leq \phi_{t,ab,i}^{dhw} \leq \phi_{t,ab,i}^{set,dhw} + \frac{\Delta^{dhw}}{2}, \quad \forall t \in T, \forall ab, i \in AB \quad (27)$$

$$\sum_t P_{t,n}^{sh} \Delta t, \sum_t P_{t,n}^{dhw} \Delta t \geq \Gamma_n, \Pi_n, \quad \forall n \in N \quad (28)$$

$$\sum_t Q_{t,ab,i}^{sh} \Delta t, \sum_t Q_{t,ab,i}^{dhw} \Delta t \geq \xi_{ab,i}, \omega_{ab,i}, \quad \forall i, ab \in AB \quad (29)$$

$$\begin{aligned}
\lambda_t = & \kappa_{t,n}^a \sum_n \left| T_{t,n}^a - T_{t,n}^{set,sh} \right| (1 - u_{t,n}^{sh}) \Delta t \\
& + \kappa_{t,n}^{dhw} \sum_n \left| T_{t,n}^{dhw} - T_{t,n}^{set,dhw} \right| \Delta t \\
& + \tau_{t,ab,i}^a \sum_{ab} \sum_i \left| \phi_{t,ab,i}^a - \phi_{t,ab,i}^{set,sh} \right| (1 - y_{t,ab,i}^{sh}) \Delta t \\
& + \tau_{t,ab,i}^{dhw} \sum_{ab} \sum_i \left| \phi_{t,ab,i}^{dhw} - \phi_{t,ab,i}^{set,dhw} \right| \Delta t, \forall t \in T
\end{aligned} \quad (30)$$

$$\begin{aligned}
SOC_{t,m}^{ev} = & SOC_{t-1,m}^{ev} - \eta_T d_{t,m}^{ev} \Delta t, \\
& \forall t \in T \text{ if } t \in [t_{1m}, t_{2m}], \forall m \in M
\end{aligned} \quad (31)$$

$$\begin{aligned}
SOC_{t,m}^{ev} = & SOC_{t-1,m}^{ev} + \eta_c P_{t,m}^{ev} \Delta t, \\
& \forall t \in T \text{ if } t \notin [t_{1m}, t_{2m}], \forall m \in M
\end{aligned} \quad (32)$$

$$P_{t,m}^{ev} \leq P_m^{ev,max}, \forall t \in T, \forall m \in M \quad (33)$$

$$SOC_m^{ev,min} \leq SOC_{t,m}^{ev} \leq SOC_m^{ev,max}, \forall t \in T, \forall m \in M \quad (34)$$

$$\sum_t P_{t,m}^{ev} \geq \alpha_m, \forall m \in M \quad (35)$$

The constraints (4) and (5) calculate the wind and solar power generation according to the investment decision at each candidate location respectively. The new capacity of RESs that will be installed at each location is bounded in (6) and (7). The constraint (8) balances the electricity demand and supply in each time step. The relationship between electricity co-generation and DH of CHP generation is expressed in Equation (9) while the total DH capacity is capped in (10). Due to a large number of DH plants and the un-availability of individual plant's specification data, the total available production capacity from the TSO can be employed and the aggregated CHP ratio is estimated as an average of a few CHP plants. The dynamics of aggregated hydro-storage is modelled in (11). The constraints (12) and (13) specify the allowable limits for dispatch-able hydropower and the storage level respectively. Equation (14) ensures that the hydro-storage level stays within the predefined band at the end of horizon. Constraint (15) requires that dispatch-able generation always satisfy a minimum set level of demand in each time slot and some free capacity is always present to handle the uncertainty and intermittency of RESs in real time.

Equation (16) captures the balance between DH demand and supply in each time slot while considering the option of DEH (renewable heat produced by electric boilers installed in the DH system) to reduce carbon emissions from DH system. It is to be noted that DH demand consists of space heating and DHW consumption of both apartment and service buildings. Equation (17) determines the total electricity demand in each time slot. This demand is the aggregation of space heating and DHW loads of detached houses, EVs charging, system critical demand and the proportion of DH demand converted to DEH. Equations (18) and (19) represent the discrete version of two-capacity building model, which is used to estimate the space heating demand of detached houses and ABs separately. Constraint (20) defines the permissible limits of indoor temperature for detached houses while constraint

(21) specifies the same for ABs when DR is unleashed. Similarly, constraints (22) and (23) set the upper boundary of heating power.

Auxiliary binary variables are introduced in (20)-(23) to relax the upper limit of indoor temperature if the outdoor temperature starts to rise on a relatively warm day. Alternatively, the indoor temperature will stay within the defined dead-band to respect the thermal comfort during the heating period. Although two-capacity model is efficient to simultaneously consider heating and cooling demand in the horizon but the above relaxation logic is implemented, since according to international standards [53], the heating demand has lower set point temperature than that of cooling demand and simultaneous heating and cooling in consecutive time slots is not valid in practical applications. Moreover, the number of cooling degree-days is extremely small in Northern Europe. In the absence of heating, the indoor ambient temperature seldom exceeds cooling set point. For this reason, the cooling demand is not considered; instead, the heating is either turned on or turned off.

Constraint (24) studies the operation of EWH for detached houses. This model uses temperature of DHW as an indication of thermal charge. The DHW usage event triggers the operation of EWH. DHW storage losses are ignored for simplicity. Constraint (25) determines corresponding DR of EWH in detached houses. Similarly, constraints (26) and (27) studies the DHW consumption and associated DR for ABs. Please note that DHW consumption in ABs does not require any water storage, instead heat exchangers are needed, so a simple model in (26) is chosen. Constraint (28) and (29) preserve the demand of each type of flexible load for each house and AB over the study period respectively, so that DR framework cannot alter the total demand. The DR cost of flexible loads is computed in (30) where the deviation from set point temperatures is penalized for each type of load and for each user. When the upper boundary of indoor temperature is relaxed, the corresponding DR cost becomes zero due to the auxiliary binary variable. The nonlinearity in (30) occurring due to the product of a continuous and binary variable can be easily linearized.

Lastly, the evolution of SOC of EVs is managed in (31) and (32). Discharging is controlled in (31) while charging is handled according to (32). Distance travelled by an EV 'm' and the time of leaving during each trip is sampled randomly. The EV 'm' is assumed to leave home at time step t_{1m} and returns home at time step t_{2m} each day of the study period. Constraint (33) limits the charging power of EV. Constraint (34) enables the EV storage to mutate between intended levels only. Finally, the EV charging demand is preserved in (35).

IV. CASE STUDY

We choose the case of Finland in this work. Finland is an EU member, that substantially needs to increase the share of RESs and decrease carbon emissions prevailing particularly in the DH sub-sector. Nevertheless, the case of neighboring systems in the Nordic region can be studied using

the proposed model. The details of generation and demand portfolio are presented below:

A. GENERATION AND DEMAND PORTFOLIO

1) BASELOAD GENERATION

The nuclear generation serves as the primary source of baseload generation in Finland. It offers almost a fixed generation level with total capacity of 2787MW. After nuclear, the electricity co-generation from CHP plants is prioritized. There are two types of CHP plants, namely district heat and industry plants. The co-generation from CHP-industry serves the baseload. Like nuclear, its generation level is also constant irrespective of the season. This cogeneration is integrated in the pulping process and thus mainly based on biofuels. Contrarily, the cogeneration of CHP-district heat follows heating demand. It is a flexible source, but a contributor to GHG emissions. The emissions produced in the cogeneration are one-third lower than only electricity production plants though. Concurrently, it is energy efficient and supports the use of various types of fuels. Due to this, the EU energy efficiency directives oblige to promote the electricity co-generation, but the relatively lower electricity spot prices do not encourage investing in the CHP-district heat [54]. Due to that, the CHP-district heat cogeneration capacity remained at almost the same level in Finland since 2008 [55]. Due to such reasons, the present capacity is utilized in this work.

2) HYDRO GENERATION

The Finnish hydro power capacity increased by just 132MW over the past decade [56]. Such a small development is mainly attributed to the geographical limitations of Finland. It is therefore assumed that the hydro generation capacity will remain constant in the future. Currently, there are more than 200 hydroelectric power plants operating in Finland [57]. Most of them have a small capacity even less than 50MW and it is difficult to acquire the operational data of all the units for aggregation. However, similar to our previous work [24], the equivalent energy values of aggregated hydro-storage and daily inflows are utilized. The aggregated hydro-storage capacity in Finland is 5.53TWh and for inflows, the median values of historical data are used as illustrated in Figure 2 [58]. Hydro generation volume is mainly driven by the cyclic inflows. Further, there is a minimum dispatch level to account for the run-of-river plants. This level needs to be maintained to enable frequency containment reserves (FCR) response under critical conditions. Hydro, being dispatchable and highly flexible, actively participates in balance management.

3) SOLAR AND WIND POWER GENERATION

The current installed wind power capacity in Finland is about 2000MW. For new capacity investments, new locations and the corresponding weather parameters are to be known. The solar irradiance and wind speed time series were adopted

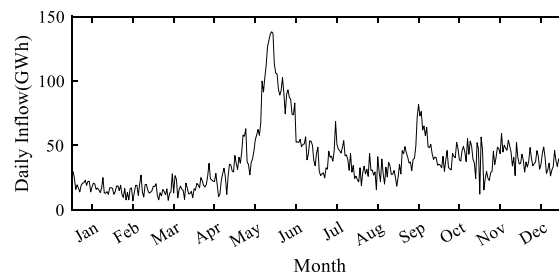


FIGURE 2. Variation of hydro inflows in Finland (Year 2017).

from [50] that uses a statistical approach aiming at new generation locations without any site-specific measured data. The methodology simulates several runs for wind speed (at 50m height above sea level) and solar irradiance time series over a one-year period, targeting 12 geographically distributed locations across Finland as depicted in Figure 3. Such time series is well suitable for long term future studies. Using these simulated series, the corresponding solar and wind power time series can be easily generated at each location. Moreover, the considered wind and solar power plants are assumed to be large-scale centralized plants that are to be connected to the national electricity system and can participate in the electricity market, i.e., Nord Pool in this case.

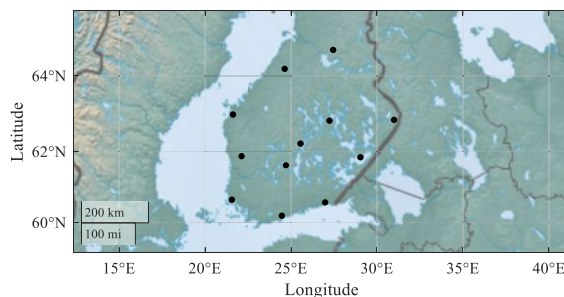


FIGURE 3. Candidate locations (marked with filled circles) for solar and wind power installations in Finland.

4) DIS-AGGREGATION OF ELECTRICITY DEMAND

We use the historical hourly electricity demand of Finland for the year 2017 available at [59]. The annual aggregated electricity demand was 83.41TWh, out of which 28% represents the residential sector. The space heating and EWH demand of detached houses are first segregated from the annual demand profile. It is assumed that there are 700,000 electrically heated detached houses that are installed with EWH units. A diversified space heating load population with respect to house areas and type is simulated using outdoor temperature profile illustrated in Figure 4. The temperature set point of heating was 21°C during heating period, which is in accordance with the standard of indoor environment [53], [60].

Similarly, a mix of EWH operation was simulated while maintaining the DHW temperature at 60°C and assuming

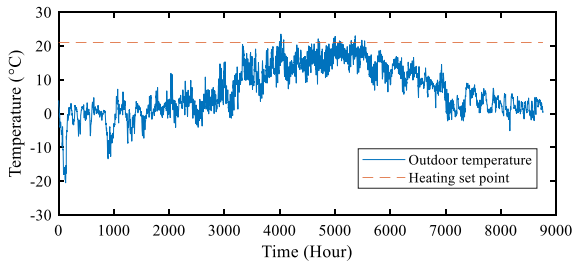


FIGURE 4. Hourly outdoor temperature profile of Southern Finland (Year 2017).

that daily DHW consumption of a household is the same throughout the year. The DHW profile is obtained from [21]. The generated space heating and EWH profiles are subtracted from the system demand to obtain critical demand. Random charging load of 0.5 Million EVs is added separately. The disaggregated demand profile is demonstrated in Figure 5.

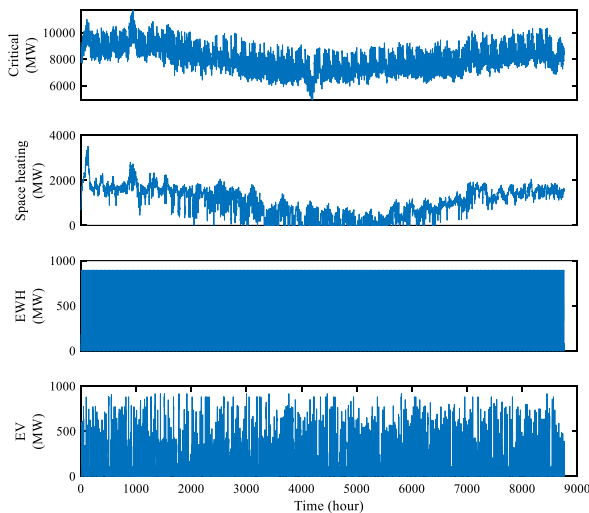


FIGURE 5. Disaggregation of hourly demand in Finland.

5) DISAGGREGATION OF DH DEMAND

The space heating and DHW demand of the building stock is satisfied by the DH network served by both the CHP and heat boilers. Total DH capacity of CHP plants in Finland is 8300MW and the total DH demand in 2017 was about 34.5TWh. Note that, contrary to the electricity system, DH network is not interconnected in Finland. Each municipality has its own DH network and heating plants. It is challenging to aggregate the hourly DH consumption at the system level with a variety of buildings in each municipality with diversified occupancy patterns. Building stock energy models *Ekorem* and *Tehorem* [61] are jointly utilized to aggregate the hourly DH consumption across Finland. *Ekorem* is a bottom-up energy calculation model of the whole building stock. *Tehorem* uses the *Ekorem* model to calculate the energy consumption hour by hour round the year using the outdoor weather data. *Tehorem* model can be used in summertime degree-days of heating according to the outdoor

temperature limits and building stock situation. Heating is therefore turned on and off accordingly but DHW is served continuously. The Network modelling and associated losses are beyond the scope of this work. However, the heat losses in the district heating network are included in the total heat demand used for the analysis, based on the statistics of the year 2017. Concurrently, when performing power to heat conversion using excess renewable energy, the DH network is assumed to be inter-connected, which is a fair assumption, since the DH network is expanding continuously (about 250-500km each year) especially in the southern part where the load center is located [54]. The simulated DH along with DHW demand is shown in Figure 6 below.

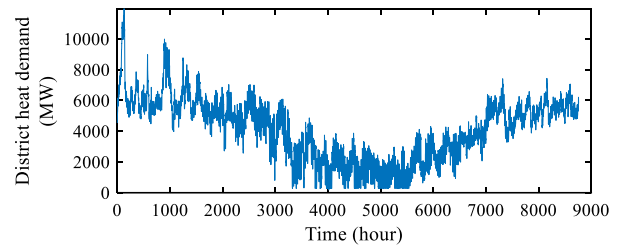


FIGURE 6. Hourly district heating profile in Finland.

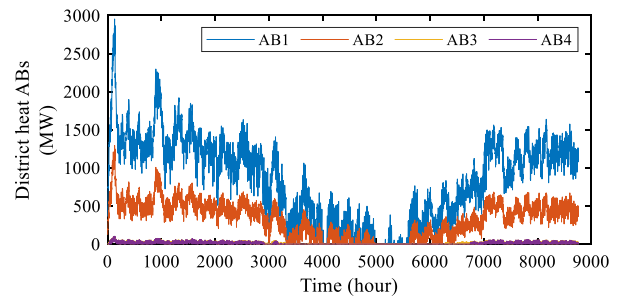


FIGURE 7. Hourly space heating demand of Finnish apartment buildings.

The DR from ABs is probed, and service buildings are treated as critical load. The total number of ABs for each category is selected according to the total built floor area. The space heating demand is estimated using the same two-capacity model, but with different parameters for each AB type. The heating profile of individual AB types is shown in Figure 7 which also demonstrates that buildings AB1 and AB2 are poorly insulated as both have minor heating demand during summer season as well. For DHW calculations in ABs, daily DHW usage of about 60 L/person and the occupancy rate of 1 person / 28m² is considered, based on the guidelines given in [62]. The DHW profile is depicted in Figure 8. Based on this, the DH demand of service buildings can be segregated from the DH profile presented in Figure 6 above.

B. SIMULATION PARAMETERS

The simulation is performed for a one-year period with time resolution of one hour. The planning period is 25 years with a yearly interest rate of 3%. The investment price for solar and wind power are 550€/kW and 1600€/kW respectively [2]. The value of lost load and lost generation

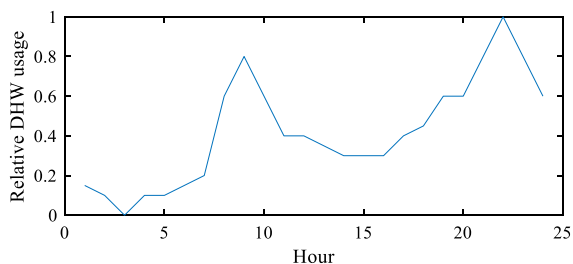


FIGURE 8. Relative DHW usage per occupant in Finnish apartment buildings.

are 4110€/MWh and 83.5€/MWh respectively. The average emission factor for DH is 176kg/MWh [5], [63]. Total CO₂ emissions in Finland for year 2017 were amounted to 55.4M-Tons [64]. The hourly emission factors according to the historical hourly electricity generation mix were utilized to compute carbon emissions imparted together by electricity and DH generation, that totals 14.85M-Tons in the ETS sector [65]. For DR framework, the thermal comfort bands for space heating loads and DHW loads are [20, 22]°C and [55, 65]°C respectively; while the associated penalties imposed on the aggregator are 0.02€/°C/hour and 0.01€/°C/hour per household respectively. To introduce diversity, house areas are randomized around mean value of 180m² with rated HVAC power of 6kW. The dimensioning power of heating system of each house or building was determined at outdoor temperature of -26°C in Southern Finland that fulfills the requirements of Finnish building code [66]. The reference ABs with heated floor areas [4050, 2638, 1585, 1585] m² are chosen. The corresponding dimensioning powers of the space heating system are [288, 128, 43, 32] kW respectively [66].

With the intent to reduce the complexity and computational burden, the houses and ABs are modelled for the climate of southern Finland where majority of the building stock is located, similar to [5]. The building stock of similar type were integrated into one group. In addition to the outdoor temperature, the effect of heat gains from occupants, electrical appliances and solar irradiance were also simulated and considered in calculating the corresponding space heating demand. Each building was assumed to be occupied during the simulation period. Please note that the critical demand cannot be changed by the aggregator.

The above optimization model was formulated as mixed integer linear programming problem that can be easily solved by any commercially available solver. The model was implemented on a desktop computer with 3.4GHz Intel Xeon processor, while it was simulated on GAMS-MATLAB platform using the CPLEX solver. The average total simulation time to obtain 10 different optimal solutions in the Pareto-front is about 7 days when DR is also considered.

C. SIMULATION RESULTS

A base case for comparison benchmark is simulated at first, which considers no coordination of electricity co-generation. In other words, the electricity cogeneration

and heat generation of CHP were assumed static as in historical profile while the heat boilers follow the residual DH demand, if any. An average scenario is opted among numerous available time series of wind speed and solar irradiance for each of the 12 locations for detailed analysis. The reference case considers new RESs capacity to replace the existing condensing power generation and electricity imports. The objective (1) transforms into a single cost function in this case, i.e., weighting coefficient is unity. This cost arises from the new investment in RESs and energy curtailments. The simulation has no control over the emissions. Further, DR is not activated and no P2H conversion is performed in the DH system. Hence, the hourly and total electricity as well as DH load profiles remains the same as showcased in Figures 5 and 6 respectively. Further, the maximum RESs capacity that can be installed at each location was limited to 2GW wind power and 1GW solar power.

The simulation results of the reference case show that the total investment of €25.76Bn is needed in the planning horizon, which calls for annuitized cost of €6.03Bn against the annual emission level of 8.09M-Ton CO₂. This investment brings an annual emission reduction of 12.2% relative to the total emissions and 45.52% reduction compared to the emissions in electricity and DH generation alone. Results further indicate that a total of 13.86GW wind power and 6.51GW solar power capacities are required across Finland to achieve this valuable reduction in emissions. Such investments would also eliminate the operation of condensing power plants as well as dependency on power imports from neighboring countries. The location wise investment decisions are illustrated in Figure 9. Despite the lower investment cost of solar power, its relatively reduced need is justified by the geography and high variation in day/nighttime duration over a yearly course.

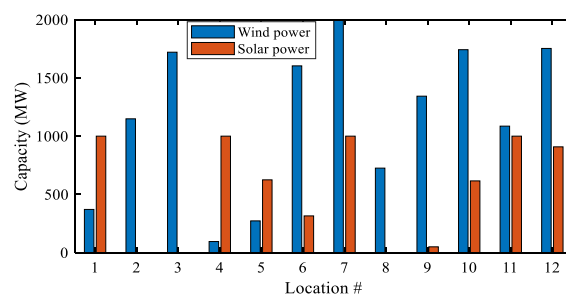


FIGURE 9. Location wise RESs investments for reference case.

This framework also leads to significant amount of electrical load and generation curtailments, i.e., 674.84GWh load and 20.89TWh RESs generation is curtailed. Moreover, 291.29GWh heat generation is also lost due to cogeneration constraint. The technology wise hourly generation profile is depicted in stacked form in Figure 10(a). Please note that the system already has total existing wind power capacity of 2000MW that was uniformly distributed among all candidate locations in this study. It is visible in Figure 10(a)

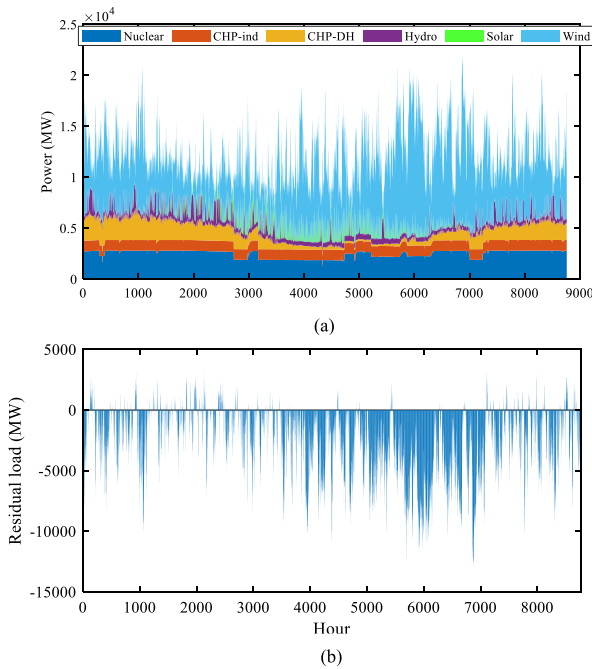


FIGURE 10. Profiles for reference case (a) Hourly disaggregated electricity generation profile (b) Curtailments.

that solar generation is extremely small during winter season, whereas in this particular scenario, most of the wind power is produced in the second half of the year when the total generation exceeds the demand most of the time as demonstrated in Figure 10(b), where the positive values represent load curtailments and negative values represent generation curtailments. This study does not probe the existing cross-border transmission links, but the surplus generation can be exported to neighboring countries. For DH demand, CHP and heat boilers share 59.5% and 40.5% load respectively in the reference case.

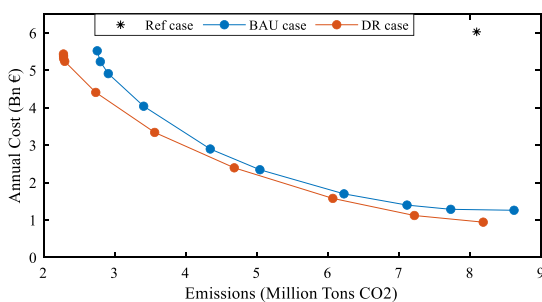


FIGURE 11. Pareto-optimal fronts and reference solution.

Simulating the proposed framework, i.e., equations (1)-(35) shows a superior performance over the reference case in terms of both the cost and emissions. The optimal Pareto-fronts for BAU and DR cases are demonstrated in Figure 11. Note that in the BAU case, the indoor and DHW temperatures are maintained at desired set points. For comparison, the outcome of the reference case is also marked

therein Figure 11. The positive effect of harnessing flexibility offered by cogeneration for RESs integration can be seen in the form of exceptional decline in both objective values. It is also visible that activating DR is more profitable for smaller weighting coefficients, after which DR tends to subdue and corresponding benefits are saturated.

For the BAU case, the annuitized cost varies from €1.26Bn to €5.52Bn while the emissions increase from 2.75Mtons to 8.62Mtons CO₂. Compared to the reference case, the least cost solution in the BAU case brings 79.10% savings in the annual cost at the expense of 6.55% increase in emissions. The same cost savings rise to 84.4% when DR is unleashed, while sacrificing the emission reductions by 1.1% only, as compared to the reference case. Similarly, the lowest emission solution in the BAU case guarantees 65.94% emission reduction potential and 8.47% decline in cost relative to the reference case, whereas the same benefits climb to 71.81% and 9.9% respectively under the umbrella of DR. Please note that both least cost solutions imply more or less the same emissions as in the reference case, but at extremely reduced cost, which also validates the proposed model.

Most often, the whole set of Pareto optimal solutions is not discoverable as there may be infinite number of optimal solutions. Hence, a well distributed set of non-dominated solutions is used as a representative. The decision maker can then select a single solution from this potential set. There are many methods proposed to support the decision process, however marginal rate of substitution approach [67] is employed here. The idea is that moving from one Pareto-solution to a neighboring Pareto-solution provides a gain in one objective while sacrificing the other. Hence, this method computes sacrifice per unit gain when moving to either direction at each solution. The solution with the largest average trade-off can be selected by the decision maker. At this solution, a small improvement in one objective results in a large deterioration of the other objective. Following this approach in Figure 11, the solution corresponding to $w = 0.9$, i.e., (€1.284Bn, 7.73M-Tons) can be selected for the BAU case and the solution against $w = 0.3$, i.e., (€5.313Bn, 2.28M-Tons) can be selected for the DR case.

A summary of the results obtained in Figure 11 is presented in Table 1. For simplicity, only three Pareto-optimal solutions are listed. Both the lowest emission solutions converge to the same total investment cost as the model invests in all the available RESs capacity defined for each candidate location. However, the annual costs are different due to energy curtailments and DR framework. The emission reductions in Table 1 are computed based on the total emissions of the Finnish energy generation sector for the year 2017. The percentage reduction is relative to the total emissions in Finland i.e., 55.4M tons. The hourly generation mix for the BAU case corresponding to $w = 0.5$ is illustrated in Figure 12. Due to constraint (15) and to avoid fossil-based DH cogeneration, the hydro generation is dispatched at high levels when RESs output is also high, leading to

TABLE 1. Summary of Pareto-optimal solutions.

Case	Solution type	Annual cost (Bn €)	Investment cost (Bn €)	Emissions (M-Ton CO ₂ /a)	Emission reduction in Energy sector (M-Ton CO ₂ /a)	Overall Relative reduction (%)
BAU case	Lowest emission	5.52	45	2.75	12.09	21.83
	Cost-neutral	2.89	28.60	4.34	10.51	18.97
	Least cost	1.26	11.9	8.62	6.23	11.24
DR case	Lowest emission	5.43	45	2.28	12.57	22.69
	Cost-neutral	3.34	32.17	3.56	11.29	20.38
	Least cost	0.94	13.24	8.18	6.67	12.04

high RESs curtailments. The investment decisions including the total investment cost over the planning horizon for each optimal solution are depicted in Figure 13, which clearly demonstrates that DR of TCLs has the potential to accommodate more RESs capacity as compared to the BAU case. It is worth noticing that DR acts to balance the investment between wind and solar power that is contrary to the BAU case where wind power significantly dominates the solar power in all solutions.

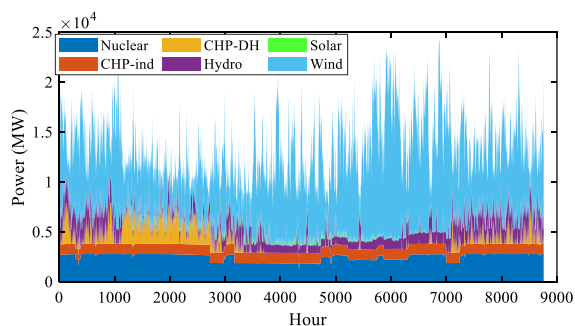


FIGURE 12. Hourly dis-aggregated electricity generation profile for BAU case (w=0.5).

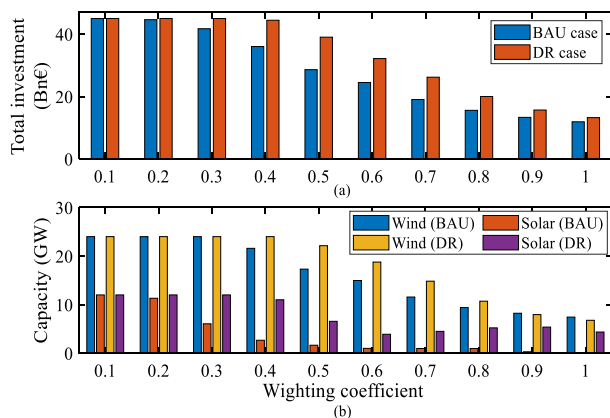


FIGURE 13. Investment decisions for Pareto-optimal solutions (a) Total investment cost (b) RESs capacity.

The breakdown of the annual cost for all optimal solutions in the Pareto-front is illustrated in Figure 14. The Figure reveals that total energy curtailments decrease for both

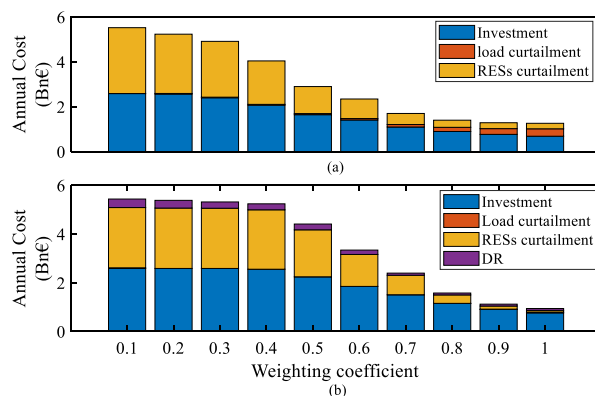


FIGURE 14. Breakdown of the annual cost (a) BAU case. (b) DR case.

cases as the investment in RESs decreases. Undoubtedly, the curtailments are mainly caused by uncontrollable RESs. The load curtailment grows gradually towards the higher cost weight in the BAU case. Contrarily, DR is proved effective in lowering load curtailments, but at a relatively small cost, thanks to the flexibility of TCLs. The annual cost in the BAU case is more sensitive to lower weighting coefficients whereas the converse is true in the case of DR. Note that load curtailments have the highest cost after RESs investment. The least cost solution achieves 0.94TWh RESs curtailments and 80.32GWh load curtailments in the BAU case, while for the same solution, DR secures 0.57TWh RESs curtailments and 8.44GWh load curtailments implying significant relative improvement of 39.36% and 89.5% respectively. 80.32GWh corresponds to 0.09% and 8.44GWh corresponds to 0.01% of total annual electricity demand that also includes P2H conversion to supply DH. To avoid such load curtailments, electricity must be generated by back-up capacity or imported from neighboring countries.

Moreover, the higher investment in RESs also specifies that more electrification of the DH sub-sector is achieved. The evolution of emission-based DH and DEH for all Pareto-optimal solutions is sketched in Figure 15. The balance point is achieved at different cost weights for the two cases, but the trend is the same and conforms to RESs investments. DR ensures higher P2H conversion at all Pareto levels and the difference is prominent for the intermediate weighting coefficients. The sum of annual DH and DEH demand at

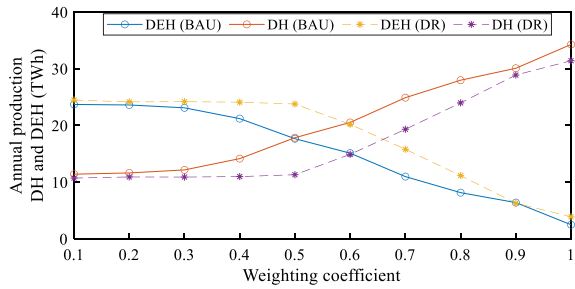


FIGURE 15. Amount of district heating and electrified heating demand in Pareto-optimal solutions.

all Pareto levels is equal to 34.5TWh, i.e., total annual DH demand in the reference case. The DH production may exceed the demand and the surplus heat can be dumped to the sea, for instance.

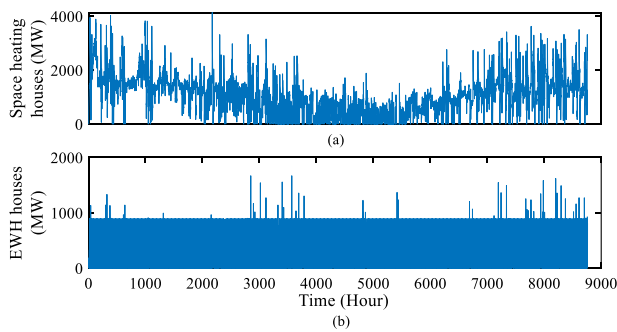


FIGURE 16. Hourly DR loads in detached houses (a) Space heating (b) Electricity usage for DHW.

It is worth mentioning that space-heating loads are far more responsive compared to DHW loads and it is applicable both to detached houses and ABs. This flexibility is due to the high thermal time constant of well-insulated buildings that enable the thermal masses act as a small storage. For clarity, the hourly profile of DR loads in houses for the optimal solution corresponding to weighting factor of 0.5 are presented in Figure 16. The upward DR (load increment) and downward DR (load reduction) capability of TCLs, especially space heating loads, can be comprehended by distinguishing this profile from the BAU case (i.e., Figure 5). Their high ramp rate effectively balances the intermittency of RESs.

The results presented so far were based on a single run of weather time series, although different for each of the 12 locations in Finland. However, to model the uncertain nature of RESs as well as study the inter-annual weather variability, the proposed model is simulated for six more weather time series for each of the candidate locations. The minimum, median and maximum value of obtained Pareto-optimal solutions are highlighted for all cases in Figure 17. Figure 18 presents the solution-wise box-whisker plot distributions of total wind and solar capacity. The total wind capacity uniformly decreases in relation to the weighting coefficient, but the mean values of solar capacity distributions tend to settle around 1.2GW. Almost all capacity distributions have narrow inter-quartile range which also

proves the effectiveness of considering 12 candidate locations in the optimization model. Such large number of candidate locations easily cater for the stochastic nature of weather inputs.

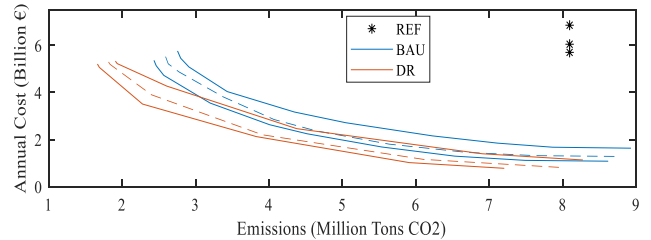


FIGURE 17. Minimum, median and maximum Pareto-solution levels for six distinct weather profiles.

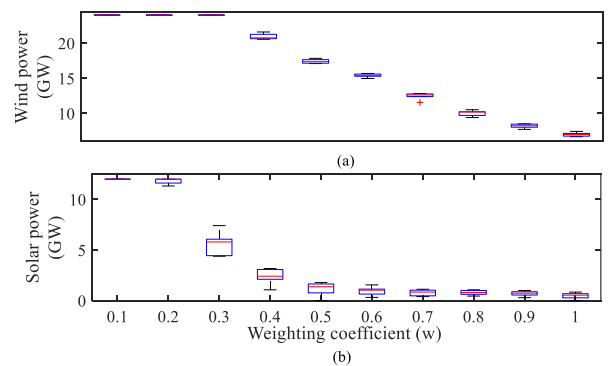


FIGURE 18. Box-plot distribution of power capacity investments in the BAU case. (a) Wind power, (b) Solar power.

V. DISCUSSION

A. SCOPE AND ASSUMPTIONS

Finding an optimal solution for a system level planning problem is a challenging task due to the operational details of energy generation and demand. The P2H sector coupling and then, the temporal resolution further aggravates the problem. Hence, some simplifications must be made concerning the mix of energy system. Curtailment costs are studied as, after investments, these concern system operators and planners the most. We use the existing capacity of nuclear, hydro, CHP-industry and CHP-district heat power generation, with the hydro and DH cogeneration as a flexible form of generation to cope with the variability of RESs in this work. Although we have assumed the current Scandinavian 3GDH system in this study, but the role of CHP is also inevitable in the 4GDH system, being a flexible and essential technology [68]. Indeed, there are costs associated with the operation and commitment statuses of these generating units. Considering such costs require individual specification data including minimum generation level, ramping limits, minimum on and off times, maximum power capacity and, in case of CHPs, power to heat ratios etc. Due to a large number of such generators and the lack of access to the technical data of individual units, the detailed operating

costs could not be incorporated in the optimization model. For instance, there are 108 CHP-district heat power plants and more than 200 hydroelectric power plants operating in Finland [57], [69].

In the Nordic region including Finland, generators participate in the Nord Pool to cover their operational and real time balancing costs. The Authors believe that the Nord Pool guarantees revenue adequacy to all generating units covered by the market. Consequently, the operational cost and the market revenue of individual generators is beyond the scope of this work. The scope of the study is limited to estimate the system level renewable energy investments for the cross-sectoral integration of electricity, DH and transport sub-sectors needed in relation to the emission reduction targets set by the EU. Further, the proposed formulation preserves the full chronology of the yearly time-series. Accordingly, in such a condition, considering operational details of the generation side can lead to computational intractability.

Moreover, Finland has transmission links with neighboring countries, such as Norway and Sweden. The electricity trade through transmission links also take place at the Nord Pool. About 98% of the total electricity production in Norway is based on RESs [70]. The electricity in Sweden mainly comes from nuclear power generation and renewables with a significant share of hydropower [71]. Hence, this nearly emission-free electricity represents a candidate of reserves that can be imported through the market platform to tackle the uncertainty and intermittency of solar and wind power. Please note that carbon emissions associated with the imported electricity needs to be considered where that electricity is produced. Such transmission interconnections are not considered in the model as it will result in under-estimation of carbon emissions produced in Finland. Further, the EU targets require individual actions from each member state. Hence, the case study is designed so that energy demands for electricity, DH and transport fuels can be met using domestic energy production, to guarantee that the renewable energy system can be accomplished without being dependent on electricity imports.

B. DIRECT ELECTRIFICATION OF TRANSPORT SUB-SECTOR

This work considered carbon emissions arising from three sub-sectors. After the electricity and DH sub-sectors, the transport sub-sector is the third highest contributor to carbon emissions. In 2017, the transport sub-sector shared 11.3Mtons (20%) of the total emissions in Finland. Currently, there are 2.7Million passenger cars in traffic use, out of which only 10,000 are electric cars [72]. Finland set a target of 250,000 EVs by 2035 to significantly cut carbon emissions in the non-ETS sector. However, the current policy is unable to achieve the desired results as contended by Etila, the Research Institute of the Finnish Economy [73]. Accordingly, we have considered 0.5 Million EVs in this study to emulate the effect of carbon emission reductions in relation to the direct electrification of the transport sub-sector.

C. LOAD GROWTH

The electricity and DH demands are used as detailed in sub-section IV-A. Load growth over the 25-year horizon is not considered due to the following reasons.

- i. The net electricity load growth in Finland over the last two decades is almost zero and the industrial electricity consumption over the past decade remained at a constant level [55].
- ii. One of the targets of the EU climate and energy framework for the 2030 horizon specifies at least 32.5% improvement in energy efficiency [74], that is why reducing the energy consumption of buildings is an important milestone of the decarbonization goal. It requires energy retrofits on the existing building stock to improve insulation and energy losses, thus decreasing the future energy demand [5], [11].
- iii. A population of 0.5 Million EVs is considered which is in line with the EU targets set for the non-ETS sector in Finland. This entails an annual demand increment of 1.38TWh, added over the annual electricity demand of 83.41TWh.

According to the aforementioned facts, the changes of present electricity demand are expected to be small in the foreseeable future. The growth of demand by EVs will at least partly compensate the electrical load reduction by energy efficiency measures. Due to sector coupling of power and heat, the total electricity demand will of course be increased as demonstrated in the simulation results.

D. UTILIZATION OF EXCESS RENEWABLE GENERATION

According to the simulation results discussed in sub-section IV-C, investment decisions of wind and solar power for all case studies results in excess renewable generation which, if not utilized, must be curtailed. Such excess RESs generation is un-avoidable in optimal solutions when large-scale storage options are not considered. Contrarily, to achieve a solution accompanied with no excess generation, i.e., a perfect hourly match, the corresponding energy system (or sub-sector) optimization would require a significantly enormous storage size of the order of TWh, worth Billions of Euros. For instance, the work [7] quantified electric storage sizes of 10TWh and 3.7TWh to transform the Danish heating system to 100% renewable using electric heating and heat pump options respectively. Such electric storages would require an investment cost of about €2000Bn and €750Bn respectively. These huge investments can be avoided by choosing a thermal storage of the same capacity instead, since in general, a thermal storage is much cheaper in terms of investment cost per unit of stored energy as compared to an electric storage [12]. Due to this fact, the option of 10TWh thermal storage would only cost €250Bn [7]. Such investment costs were additional to the investments needed in wind power capacity, heat pumps and network. Moreover, such huge investments would only transform the Danish heating system to a 100% renewable sub-sector. In practice, huge investment in a system or

sector-wide storage installation is not justified due to the following reasons:

- i. Additional lifetime O&M costs, and storage losses in combination with low utilization.
- ii. Besides storage capacity, the charging capability of such a storage needs to be compatible with the maximum level of renewable energy generation at any hour during the planning horizon. Designing huge storages for such high charging levels is not always possible.
- iii. The total cost of the storage system is manyfold higher than the cost of renewable generation installments in the electricity grid.

Further, the above cited costs of heating system transformation imply to a small country, Denmark. Such costs will immensely soar when similar measures are done in relatively bigger countries, such as Sweden and Finland.

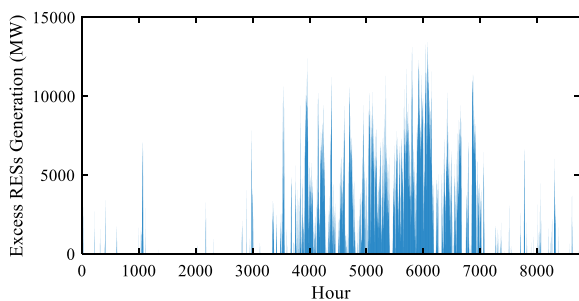


FIGURE 19. Excess renewable generation in the cost-neutral solution (BAU case).

TABLE 2. Renewable generation curtailments for Pareto-optimal solutions.

Weighting coefficient (w)	Excess Renewable Generation (TWh)	
	BAU Case	DR Case
0.1	31.72	29.43
0.2	31.47	29.66
0.3	29.58	29.58
0.4	22.89	29.19
0.5	13.94	23.08
0.6	9.8	15.67
0.7	4.98	9.54
0.8	2.58	4.08
0.9	1.5	1.4
1	0.94	0.57

Due to such concerns, this work did not consider the storage as an investment option. Instead, the amount of excess renewable energy generation resulting from the model can be utilized to further mitigate emissions in sub-sectors. For clarity, the solution-wise annual excess RESs generation is listed in Table 2. Note that the cost-neutral solution in the BAU case yields total excess generation of 13.94TWh, i.e., 40% of the total DH demand in Finland (except industry-based). The corresponding excess hourly renewable generation is shown in Figure 19 which depicts that most

of the excess generation occurs during the summer season when both electricity and heat demand are low. The excess generation level can approximately reach as high as 13GW. Although, this excess amount of generation is penalized in the objective function that contributed to the annuitized cost, but it can be utilized for further cross-sectoral integration, for example, power to gas applications to produce green gas and green liquid fuel using conversion technologies, i.e., besides direct electrification of the transport sub-sector [75], [76], or in the DH application involving thermal storage and seasonal storage [77], [78] as detailed in the following sub-sections. Utilizing this excess renewable generation would cut down both the annuitized cost and carbon emissions, according to (1)-(3).

1) POWER TO TRANSPORT (GAS AND LIQUID FUELS)

The current biomass resources are unable to satisfy the transport demand in the future renewable energy system due to their high demand for other purposes [79]. Moreover, direct electrification of the transport sub-sector, i.e., EVs, have limited potential and it cannot satisfy all the transport needs. Some parts of the sub-sector such as aviation and marine industry will still rely on liquid and/or gaseous fuels which can be produced by renewable energy. This challenge requires an additional coupling between electricity and transport sub-sectors. Electro fuels have been regarded as this needed additional link which connects variable renewable generation to large-scale fuel storage. Electro fuels store electrical energy as liquid or gaseous fuels. First, the fluctuating electricity is converted into hydrogen by the electrolysis of water. The hydrogen generated during electrolysis is an energy carrier and not an energy source. It is transformed into hydrocarbons (via biomass, biogas, or CO₂ hydrogenation) such as methane, methanol and other gaseous fuels [80]. The synthesized hydrogen can also be merged with a nitrogen source to produce ammonia. Such renewable fuels can be easily stored and transported. Liquid and gaseous fuel storage technologies are substantially cheaper than both electric and thermal storages [12]. Further, fuel cell electric vehicle (FCEV), powered by hydrogen generated from renewable energy, is a low emission mobility option and it is complementary to the battery EV with driving performance similar to the conventional vehicle.

The electrolysis is performed through an electrolyser. An electrolyser is a flexible load that can follow the intermittent generation of wind and solar and it can provide regulation power due to its fast response time (i.e., 100% ramp-up and down per second). A typical example is the proton exchange membrane (PEM) electrolyser consuming 58kWh electricity per kg of H₂ produced [81]. According to a Belgian case study [81], [82], an electrolyser with a power rating of 0.2MW can produce 900kg of H₂ daily, which is enough to refuel 25 buses powered by hydrogen fuel cells. The levelized cost of producing this hydrogen is expected to fall below US\$ 4/kg for the electrolyser utilization rate exceeding 50% in the future scenario [81].

From this point of departure, 13.94TWh excess renewable generation for cost-neutral solution simulated in this work can produce 2.61M-Tons H₂ per annum which is quite enough to meet the annual fuel demand of a few Million FCEVs and several thousand buses. Such dynamics endorse the utilization of excess renewable generation for power to gaseous and liquid fuel conversion at the expense of cheap storage technologies.

2) DISTRICT HEATING STORAGE

The district heating (DH) storage includes large steel water tanks, thermal inertia of connected buildings, seasonal storage associated with solar thermal plants and long-term storage in boreholes and pits [83]. As depicted in the simulation results, most of the excess renewable generation occurs in the summer season, therefore it is well suitable to utilize it in seasonal thermal storage in connection to district heating. However, the major thermal storage capacity is offered by the water in the thermal grid itself. DH companies sometimes increase the forward temperature prior to the peak hours. As an example, increasing the forward temperature by 10°C leads to a storage capacity of 2.6TWh, which is substantial as compared to the annual DH demand [7]. Similar storage capacity can be harnessed in the Finnish thermal grid by utilizing excess renewable generation. Such an inherent storage does not need any investment. Besides excess renewable generation, the cost-neutral solution in the BAU case yields 390.8GWh excess heat produced by the CHP generation due to cogeneration and flexibility constraints (9) and (15) respectively. This excess heat utilization can cut down operation of CHP units and boilers to bring about further emission and fuel savings [84]. Consequently, CHP units can operate on more markets in different time horizons to make adequate profit [85].

Besides storages, the future smart thermal grid necessitates the heat distribution among low-energy buildings via the DH network, i.e., two-way DH [15], [16]. This feature also endorses the concept of net zero energy buildings (NZEB) supplemented by coordination with the heat network. The hot water storage tanks and solar power installations in the future buildings would offer a great potential to exchange heat energy as well. The cross-sectoral integration involving DH network and storages can also enhance the benefits of cross-border transmission interconnections, since the excess renewable generation can be used anywhere in the system which results in further flexibility [86].

VI. CONCLUSION

In this work, the coupling between electricity, district heat and transport sub-sectors is studied from system's perspective by considering both the smart grid and energy system's strategy. The proposed framework aims to jointly minimize the RESs investment cost and the carbon emissions, as this issue being a matter of prime importance to the EU. Detailed simulations were performed to retain the correlations among various parameters and preserve the chronology. The results

from the Finnish case study show that utilizing the flexibility offered by electricity cogeneration in DH system can bring significant benefits in the form of cost and emission reduction. DR of TCLs, particularly space heating loads are capable to provide further aid by accommodating more RESs capacity at relatively lower annual cost. Alternatively, DR enrollment can be tuned by the aggregator according to the preferable objective as it is not obvious that it would remarkably outperform in both objectives at all Pareto levels against the BAU case. The important results are highlighted as under:

- Simulation results proved that DR benefits are more tailored towards power quality improvements such as load curtailment reductions. Compared with the reference case, the proposed framework under DR is capable to reduce the total investment cost by one-half for the same amount of emissions, i.e., €25.76Bn cost in the reference case reduced to just €13.24Bn in the least-cost solution. Such an investment corresponds to an overall emission reduction of 12.04% in Finland.
- Moreover, the excess renewable generation resulting from the investments can be further utilized, for instance, by exporting to neighboring countries or in power to gaseous and liquid fuel applications, resulting in further decrease of carbon emissions. The excess renewable generation, as simulated for the Finnish case, is substantial to mitigate emissions in the transport sub-sector requiring relatively smaller investments in hydrogen-based technology. In addition, the inherent storage capacity in the thermal grid can be utilized for short-term storage of excess renewable generation without requiring any additional cost.
- The obtained optimal solutions in this study outperform in both the investment cost and carbon emission reductions when compared with the retrofitting of the Finnish building stock limited to apartment buildings and detached houses [5], [11], as discussed in Section I.
- Lastly, due to flexibility requirements in the electrical grid, 100% renewable electricity system and consequently 100% renewable energy system is not practically possible. An economical option is to find a balance between investment costs and carbon emissions while creating synergies among various sub-sectors in the energy system, following the utilization of excess renewable generation and heat, further linking sub-sectors to promote more emission reductions and fuel savings.

In the future, the DH system shall be further explored in the context of 4GDH. The option of storages in the form of heat wells (1-2km deep) installed in DH system shall be considered to estimate the power sink and resource capability for RESs integration and further reduction in carbon emissions. Further, the effect of DR penetration shall be studied on investments and curtailments. Moreover, load flows shall be incorporated to study the impact of high RESs

penetration on low voltage ride through (LVRT) performance according to grid codes.

REFERENCES

- [1] (2019). *European Commission*. [Online]. Available: https://ec.europa.eu/clima/policies/strategies/2050_en#tab-0-1
- [2] N. Helistö, J. Kiviluoma, and H. Holttinen, "Long-term impact of variable generation and demand side flexibility on thermal power generation," *IET Renew. Power Gener.*, vol. 12, no. 6, pp. 718–726, Apr. 2018.
- [3] L. Reichenberg, F. Hedenus, M. Odenberger, and F. Johnsson, "Tailoring large-scale electricity production from variable renewable energy sources to accommodate baseload generation in Europe," *Renew. Energy*, vol. 129, pp. 334–346, Dec. 2018.
- [4] *Directive 2010/31/EU of the European Parliament and the Council on the Energy Performance of Buildings*, The European Parliament and the Council of the European Union, Brussels, Belgium, 2010.
- [5] J. Hirvonen, J. Jokisalo, J. Heljo, and R. Kosonen, "Towards the EU emissions targets of 2050: Optimal energy renovation measures of Finnish apartment buildings," *Int. J. Sustain. Energy*, vol. 38, no. 7, pp. 649–672, Dec. 2018.
- [6] U. Persson, B. Möller, and S. Werner, "Heat roadmap Europe: Identifying strategic heat synergy regions," *Energy Policy*, vol. 74, pp. 663–681, Nov. 2014.
- [7] H. Lund, "Renewable heating strategies and their consequences for storage and grid infrastructures comparing a smart grid to a smart energy systems approach," *Energy*, vol. 151, pp. 94–102, May 2018.
- [8] H. Lund, P. A. Østergaard, D. Connolly, and B. V. Mathiesen, "Smart energy and smart energy systems," *Energy*, vol. 137, pp. 556–565, Oct. 2017.
- [9] R. Holopainen, A. Milandru, H. Ahvenniemi, and T. Häkkinen, "Feasibility studies of energy retrofits—Case studies of nearly zero-energy building renovation," *Energy Procedia*, vol. 96, pp. 146–157, Sep. 2016.
- [10] M. Gustafsson, C. Dipasquale, S. Poppi, A. Bellini, R. Fedrizzi, C. Bales, F. Ochs, M. Sié, and S. Holmberg, "Economic and environmental analysis of energy renovation packages for European office buildings," *Energy Buildings*, vol. 148, pp. 155–165, Aug. 2017.
- [11] J. Hirvonen, J. Jokisalo, J. Heljo, and R. Kosonen, "Towards the EU emission targets of 2050: Cost-effective emission reduction in Finnish detached houses," *Energies*, vol. 12, no. 22, p. 4395, Nov. 2019.
- [12] H. Lund, P. A. Østergaard, D. Connolly, I. Ridjan, B. V. Mathiesen, J. Z. Thellufsen, and P. Sorknæs, "Energy storage and smart energy systems," *Int. J. Sustain. Energy Planning Manage.*, vol. 11, pp. 3–14, Oct. 2016.
- [13] J. Hirvonen, J. Jokisalo, J. Heljo, and R. Kosonen, "Effect of apartment building energy renovation on hourly power demand," *Int. J. Sustain. Energy*, vol. 38, no. 10, pp. 918–936, May 2019.
- [14] J. Ziemele, E. Cilinskis, and D. Blumberga, "Pathway and restriction in district heating systems development towards 4th generation district heating," *Energy*, vol. 152, pp. 108–118, Jun. 2018.
- [15] H. Lund, S. Werner, R. Wiltshire, S. Svendsen, J. E. Thorsen, F. Hvelplund, and B. V. Mathiesen, "4th generation district heating (4GDH)," *Energy*, vol. 68, pp. 1–11, Apr. 2014.
- [16] H. Lund, P. A. Østergaard, M. Chang, S. Werner, S. Svendsen, P. Sorknæs, J. E. Thorsen, F. Hvelplund, B. O. G. Mortensen, B. V. Mathiesen, C. Bojesen, N. Duic, X. Zhang, and B. Möller, "The status of 4th generation district heating: Research and results," *Energy*, vol. 164, pp. 147–159, Dec. 2018.
- [17] K. Helin, J. Jaaskelainen, and S. Syri, "Energy security impacts of decreasing CHP capacity in Finland," in *Proc. 15th Int. Conf. Eur. Energy Market (EEM)*, Jun. 2018, pp. 1–5.
- [18] P. Sorknæs, H. Lund, I. R. Skov, S. Djørup, K. Skytte, P. E. Morthorst, and F. Fausto, "Smart energy markets—future electricity, gas and heating markets," *Renew. Sustain. Energy Rev.*, vol. 119, Mar. 2020, Art. no. 109655.
- [19] P. J. Ramirez, D. Papadaskalopoulos, and G. Strbac, "Co-optimization of generation expansion planning and electric vehicles flexibility," *IEEE Trans. Smart Grid*, vol. 7, no. 3, pp. 1609–1619, May 2016.
- [20] R. Deng, Z. Yang, M. Chow, and J. Chen, "A survey on demand response in smart grids: Mathematical models and approaches," *IEEE Trans. Ind. Informat.*, vol. 11, no. 3, pp. 570–582, Jun. 2015.
- [21] A. A. Bashir, M. Pourakbari-Kasmaei, J. Contreras, and M. Lehtonen, "A novel energy scheduling framework for reliable and economic operation of islanded and grid-connected microgrids," *Electr. Power Syst. Res.*, vol. 171, pp. 85–96, Jun. 2019.
- [22] M. Ali, A. Safdarian, and M. Lehtonen, "Demand response potential of residential HVAC loads considering users preferences," in *Proc. IEEE PES Innov. Smart Grid Technol., Eur.*, Oct. 2014, pp. 1–6.
- [23] M. Safdar, G. A. Hussain, and M. Lehtonen, "Costs of demand response from residential customers' perspective," *Energies*, vol. 12, no. 9, p. 1617, Apr. 2019.
- [24] A. Bashir and M. Lehtonen, "Optimal coordination of aggregated hydro-storage with residential demand response in highly renewable generation power system: The case study of Finland," *Energies*, vol. 12, no. 6, p. 1037, Mar. 2019.
- [25] A. Bashir, M. Pourakbari Kasmaei, A. Safdarian, and M. Lehtonen, "Matching of local load with on-site PV production in a grid-connected residential building," *Energies*, vol. 11, no. 9, p. 2409, Sep. 2018.
- [26] A. Safdarian, M. Ali, M. Fotuhi-Firuzabad, and M. Lehtonen, "Domestic EWH and HVAC management in smart grids: Potential benefits and realization," *Electr. Power Syst. Res.*, vol. 134, pp. 38–46, May 2016.
- [27] M. Ali, J. Jokisalo, K. Siren, and M. Lehtonen, "Combining the demand response of direct electric space heating and partial thermal storage using LP optimization," *Electr. Power Syst. Res.*, vol. 106, pp. 160–167, Jan. 2014.
- [28] N. Helistö, J. Kiviluoma, H. Holttinen, J. D. Lara, and B. Hodge, "Including operational aspects in the planning of power systems with large amounts of variable generation: A review of modeling approaches," *WIREs Energy Environ.*, vol. 8, no. 5, Mar. 2019, Art. no. e341.
- [29] M. Asensio, P. M. de Quevedo, G. Munoz-Delgado, and J. Contreras, "Joint distribution network and renewable energy expansion planning considering demand response and energy storage—Part I: Stochastic programming model," *IEEE Trans. Smart Grid*, vol. 9, no. 2, pp. 655–666, Mar. 2018.
- [30] P. Nahmmacher, E. Schmid, L. Hirth, and B. Knopf, "Carpe diem: A novel approach to select representative days for long-term power system modeling," *Energy*, vol. 112, pp. 430–442, Oct. 2016.
- [31] M. Ali, R. J. Millar, and M. Lehtonen, "A framework to split the benefits of DR between wind integration and network management," *IEEE Trans. Power Syst.*, vol. 33, no. 2, pp. 1443–1450, Mar. 2018.
- [32] F. Wiese, R. Bramstoft, H. Koduvere, A. P. Alonso, O. Balyk, J. G. Kirkerud, Å. G. Tveten, T. F. Bolkesjø, M. Münster, and H. Ravn, "Balmore open source energy system model," *Energy Strategy Rev.*, vol. 20, pp. 26–34, Apr. 2018.
- [33] M. Pourakbari-Kasmaei, M. Asensio, M. Lehtonen, and J. Contreras, "Trilateral planning model for integrated community energy systems and PV-based prosumers—A bilevel stochastic programming approach," *IEEE Trans. Power Syst.*, vol. 35, no. 1, pp. 346–361, Jan. 2020.
- [34] J. Sardi, N. Mithulananthan, M. Gallagher, and D. Q. Hung, "Multiple community energy storage planning in distribution networks using a cost-benefit analysis," *Appl. Energy*, vol. 190, pp. 453–463, Mar. 2017.
- [35] G. Munoz-Delgado, J. Contreras, and J. M. Arroyo, "Joint expansion planning of distributed generation and distribution networks," *IEEE Trans. Power Syst.*, vol. 30, no. 5, pp. 2579–2590, Sep. 2015.
- [36] S. Pereira, P. Ferreira, and A. I. F. Vaz, "Generation expansion planning with high share of renewables of variable output," *Appl. Energy*, vol. 190, pp. 1275–1288, Mar. 2017.
- [37] S. Montoya-Bueno, J. I. Muñoz, and J. Contreras, "A stochastic investment model for renewable generation in distribution systems," *IEEE Trans. Sustain. Energy*, vol. 6, no. 4, pp. 1466–1474, Oct. 2015.
- [38] G. Muñoz-Delgado, J. Contreras, and J. M. Arroyo, "Multistage generation and network expansion planning in distribution systems considering uncertainty and reliability," *IEEE Trans. Power Syst.*, vol. 31, no. 5, pp. 3715–3728, Sep. 2016.
- [39] J. M. Home-Ortiz, O. D. Melgar-Dominguez, M. Pourakbari-Kasmaei, and J. R. S. Mantovani, "A stochastic mixed-integer convex programming model for long-term distribution system expansion planning considering greenhouse gas emission mitigation," *Int. J. Electr. Power Energy Syst.*, vol. 108, pp. 86–95, Jun. 2019.
- [40] M. Zeinaddini-Meymand, M. Rashidinejad, A. Abdollahi, M. Pourakbari-Kasmaei, and M. Lehtonen, "A demand-side management-based model for G&T&P problem considering FSC allocation," *IEEE Syst. J.*, vol. 13, no. 3, pp. 3242–3253, Sep. 2019.
- [41] M. Zeyringer, J. Price, B. Fais, P.-H. Li, and E. Sharp, "Designing low-carbon power systems for Great Britain in 2050 that are robust to the spatiotemporal and inter-annual variability of weather," *Nature Energy*, vol. 3, no. 5, pp. 395–403, May 2018.

- [42] J. Ikäheimo, E. Pursiheimo, J. Kiviluoma, and H. Holttinen, "Role of power to liquids and biomass to liquids in a nearly renewable energy system," *IET Renew. Power Gener.*, vol. 13, no. 7, pp. 1179–1189, May 2019.
- [43] L. Söder, P. D. Lund, H. Koduvere, T. F. Bolkesjø, G. H. Rossebø, E. Rosenlund-Soysal, K. Skytte, J. Katz, and D. Blumberga, "A review of demand side flexibility potential in Northern Europe," *Renew. Sustain. Energy Rev.*, vol. 91, pp. 654–664, Aug. 2018.
- [44] *Statistics Finland*. Accessed: Sep. 16, 2019. [Online]. Available: http://stat.fi/til/asen/2017/asen_2017_2018-11-22_tau_002_fi.html
- [45] H. Wang, W. Yin, E. Abdollahi, R. Lahdelma, and W. Jiao, "Modelling and optimization of CHP based district heating system with renewable energy production and energy storage," *Appl. Energy*, vol. 159, pp. 401–421, Dec. 2015.
- [46] J. Kiviluoma and P. Meibom, "Influence of wind power, plug-in electric vehicles, and heat storages on power system investments," *Energy*, vol. 35, no. 3, pp. 1244–1255, Mar. 2010.
- [47] A. Alahäivälä and M. Lehtonen, "Increasing the benefit from cost-minimizing loads via centralized adjustments," *Energies*, vol. 9, no. 12, p. 983, Nov. 2016.
- [48] A. Alahäivälä, J. Corbishley, J. Ekström, J. Jokisalo, and M. Lehtonen, "A control framework for the utilization of heating load flexibility in a day-ahead market," *Electr. Power Syst. Res.*, vol. 145, pp. 44–54, Apr. 2017.
- [49] B. Zakeri, S. Syri, and S. Rinne, "Higher renewable energy integration into the existing energy system of Finland—Is there any maximum limit?" *Energy*, vol. 92, pp. 244–259, Dec. 2015.
- [50] J. Ekström, M. Koivisto, and I. Mellin, "A statistical model for hourly large-scale wind and photovoltaic generation in new locations," *IEEE Trans. Sustain. Energy*, vol. 8, no. 4, pp. 1383–1393, Oct. 2017.
- [51] *National Travel Survey Finland*. Accessed: Sep. 17, 2019. [Online]. Available: www.vayla.fi
- [52] B. Alimohammadisagvand, S. Alam, M. Ali, M. Degefa, J. Jokisalo, and K. Sirén, "Influence of energy demand response actions on thermal comfort and energy cost in electrically heated residential houses," *Indoor Built Environ.*, vol. 26, no. 3, pp. 298–316, Mar. 2017.
- [53] *Indoor Environmental Input Parameters for Design and Assessment of Energy Performance of Buildings Addressing Indoor Air Quality, Thermal Environment, Lighting and Acoustics*, Standard European EN 15251, 2007.
- [54] *Finnish Energy*. Accessed: Sep. 17, 2019. [Online]. Available: https://energia.fi/en/energy_sector_in_finland/energy_production/combined_heat_and_power_generation
- [55] *Energy Year 2020*, Finnish Energy, Helsinki, Finland, 2021.
- [56] *Renewable Capacity Statistics*, IRENA, Abu Dhabi, United Arab Emirates, 2020.
- [57] Finnish Energy, *Electricity Generation in Finland*. Accessed: Mar. 5, 2021. [Online]. Available: https://energia.fi/en/energy_sector_in_finland/energy_production/electricity_generation
- [58] *Nord-Pool*. Accessed: Sep. 17, 2019. [Online]. Available: <https://www.nordpoolgroup.com/>
- [59] *Fingrid Finland*. Accessed: Dec. 1, 2018. [Online]. Available: www.fingrid.fi
- [60] *Decree (1009/2017) of the Ministry of the Environment on Indoor Climate and Ventilation in the New Building*, Dept. Ministry Environ. Housing Building, Helsinki, Finland, 2017.
- [61] M. K. Mattinen, J. Heljo, J. Vihola, A. Kurvinen, S. Lehtoranta, and A. Nissinen, "Modeling and visualization of residential sector energy consumption and greenhouse gas emissions," *J. Cleaner Prod.*, vol. 81, pp. 70–80, Oct. 2014.
- [62] *D3, Energy Efficiency of Buildings*, Ministry of the Environment, Helsinki, Finland, 2014.
- [63] (2019). *Motiva*. Accessed: Nov. 8, 2019. [Online]. Available: <https://www.motiva.fi/ratkaisut/energian kaytto-suomessa/co2-paastokertoimet>
- [64] *Statistics Finland*. Accessed: Oct. 15, 2019. [Online]. Available: http://www.stat.fi/til/khki/2018/khki_2018_2019-12-12_tie_001_en.html
- [65] *Finnish Energy*. Accessed: Dec. 20, 2019. [Online]. Available: <https://energia.fi>
- [66] *Decree of the Ministry of the Environment on the Energy Performance of the New Building (1010/2017)*, Ministry Environ., Helsinki, Finland, 2018.
- [67] J. Branke, K. Deb, H. Dierolf, and M. Osswald, "Finding knees in multi-objective optimization," in *Proc. Int. Conf. Parallel Problem Solving From Nature*, 2004, pp. 722–731.
- [68] A. Volkova, V. Mašatin, and A. Siirde, "Methodology for evaluating the transition process dynamics towards 4th generation district heating networks," *Energy*, vol. 150, pp. 253–261, May 2018.
- [69] *District Heating in Finland 2017*, Finnish Energy, Helsinki, Finland, 2017.
- [70] Government of Norway. *Renewable Energy Production in Norway*. Accessed: Mar. 9, 2021. [Online]. Available: <https://www.regjeringen.no/en/topics/energy/renewable-energy/id2000124/>
- [71] *Energy in Sweden*, Swedish Energy Agency, Eskilstuna, Sweden, 2019.
- [72] Statistics Finland, Helsinki, Finland, 2020.
- [73] *Suomen CO₂-Päästöt 2019–2023 Ja Hiilineutraalisuustavoitteen Saavuttaminen*, Research Institute of the Finnish Economy (ETLA), Helsinki, Finland, 2020.
- [74] E. Commission. *2030 Climate & Energy Framework*. Accessed: Jan. 10, 2020. [Online]. Available: https://ec.europa.eu/clima/policies/strategies/2030_en
- [75] B. Nastasi and G. Lo Basso, "Hydrogen to link heat and electricity in the transition towards future smart energy systems," *Energy*, vol. 110, pp. 5–22, Sep. 2016.
- [76] K. Skytte, A. Pizarro, and K. B. Karlsson, "Use of electric vehicles or hydrogen in the Danish transport sector in 2050?" *Wiley Interdiscipl. Rev., Energy Environ.*, vol. 6, no. 1, p. e233, Jan. 2017.
- [77] R. Mikulandric, G. Krajačić, N. Duić, G. Khavin, H. Lund, and B. V. Mathiesen, "Performance analysis of a hybrid district heating system: A case study of a small town in Croatia," *J. Sustain. Develop. Energy, Water Environ. Syst.*, vol. 3, no. 3, pp. 282–302, Sep. 2015.
- [78] D. Olsthoorn, F. Haghghat, and P. A. Mirzaei, "Integration of storage and renewable energy into district heating systems: A review of modelling and optimization," *Sol. Energy*, vol. 136, pp. 49–64, Oct. 2016.
- [79] L. Hamelin, M. Borzęcka, M. Kozak, and R. Pudełko, "A spatial approach to bioenergy: Quantifying the residual biomass potential in the EU-27," *Renew. Sustain. Energy Rev.*, vol. 100, pp. 127–142, Feb. 2019.
- [80] I. Ridjan, B. V. Mathiesen, and D. Connolly, "Terminology used for renewable liquid and gaseous fuels based on the conversion of electricity: A review," *J. Cleaner Prod.*, vol. 112, pp. 3709–3720, Jan. 2016.
- [81] F. Wiese, R. Bramstoft, H. Koduvere, A. P. Alonso, O. Balyk, J. G. Kirkerud, Å. G. Tveten, T. F. Bolkesjø, M. Münster, and H. Ravn, "Hydrogen from renewable power: Technology outlook for the energy transition," *Energy Strategy Rev.*, vol. 20, pp. 26–34, Apr. 2018.
- [82] *National Implementation Plan: Hydrogen Refuelling Infrastructure Belgium*, WaterstofNet, Belgium, 2015.
- [83] J. Hennessy, H. Li, F. Wallin, and E. Thorin, "Flexibility in thermal grids: A review of short-term storage in district heating distribution networks," *Energy Procedia*, vol. 158, pp. 2430–2434, Feb. 2019.
- [84] M. Wahlroos, M. Pärssinen, J. Manner, and S. Syri, "Utilizing data center waste heat in district heating—Impacts on energy efficiency and prospects for low-temperature district heating networks," *Energy*, vol. 140, pp. 1228–1238, Dec. 2017.
- [85] P. Sorknæs, H. Lund, and A. N. Andersen, "Future power market and sustainable energy solutions—The treatment of uncertainties in the daily operation of combined heat and power plants," *Appl. Energy*, vol. 144, pp. 129–138, Apr. 2015.
- [86] J. Z. Thellufsen and H. Lund, "Cross-border versus cross-sector interconnectivity in renewable energy systems," *Energy*, vol. 124, pp. 492–501, Apr. 2017.



ARSLAN AHMAD BASHIR received the bachelor's degree in electrical engineering from the University of Engineering and Technology Lahore, Pakistan, in 2011, and the master's degree in electrical engineering and electrical systems from Aalto University, Finland, in 2016, where he is currently pursuing the Ph.D. degree in electrical engineering. He has worked as a Design Engineer with the Electricity Transmission System Operator of Pakistan, from 2012 to 2014, and from 2016 to

2017. His research interests include demand response modeling of thermostatically controlled loads, renewable energy integration, power and heat sector coupling, time-period clustering, as well as power system operation, planning, and economics.



JUHA JOKISALO was born in Pori, Finland, in 1971. He received the M.Sc. degree in physics from Helsinki University, Finland, in 1999, and the D.Sc. (Tech.) degree from Helsinki University of Technology, Espoo, Finland, in 2008. Currently, he is a Senior Scientist at the Department of Mechanical Engineering, Aalto University. His research interests include energy efficiency of buildings and dynamic building simulation.



JUHANI HELJO's long career at Tampere University, Finland, mainly consists of research work of energy economy and energy saving in buildings. The biggest enthusiasm was to create energy models of the whole Finnish building stock. The first purpose was to calculate the effect of new building codes of energy, then to estimate greenhouse gas emissions followed by electricity peak power needs and possibilities to demand side management of electricity consumption. He has made several books on energy saving in Finnish buildings—unfortunately in Finnish language. In recent years before his retirement, he has coauthored several interesting articles.



AMIR SAFDARIAN is a Senior Scientist at VTT Technical Research Centre of Finland. He has been a Faculty Member at Sharif University of Technology, Iran, since 2015. He has extensive teaching and research experience. His research interests include electric power distribution system operation and planning, smart grid related issues, and energy system reliability and resilience. He was a recipient of several national and international awards, including the 2013 IEEE Power System Operation Transactions Prize Paper Award. He was on the list of outstanding reviewers of IEEE TRANSACTIONS ON SUSTAINABLE ENERGY for 2016. Since 2019, he has been an Associate Editor of *IET Generation, Transmission & Distribution*.



MATTI LEHTONEN received the master's and Licentiate degrees in electrical engineering from Helsinki University of Technology, in 1984 and 1989, respectively, and the Doctor of Technology degree from Tampere University of Technology, in 1992. He was with VTT Energy, Espoo, Finland, from 1987 to 2003, and has been a Professor at Helsinki University of Technology, since 1999. Currently, he is with Aalto University, where he is the Head of power systems and high voltage engineering. His main activities include power system planning and asset management, power system protection including earth fault problems, harmonic related issues, and applications of information technology in distribution systems.

...