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# Improved flexibility with large-scale variable renewable power in cities through optimal demand side management and power-to-heat conversion

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## Highlights

- New models for optimal control of shiftable loads and power-to-heat conversion.
- Full technical and economic potential with optimal controls.
- Detailed time series of shiftable loads based on empirical data.
- Case study of Helsinki (Finland) with over 90% share of district heating.
- Positive net present values in cost-optimal operation.

## Abstract

Solar and wind power are potential carbon-free energy solutions for urban areas, but they are also subject to large variability. At the same time, urban areas offer promising flexibility solutions for balancing variable renewable power. This paper presents models for optimal control of power-to-heat conversion to heating systems and shiftable loads in cities to incorporate large variable renewable power schemes. The power-to-heat systems comprise heat pumps, electric boilers, and thermal storage. The control strategies comprise optimal matching of load and production, and cost-optimal market participation with investment analysis. All analyses are based on hourly data. The models are applied to a case study in Helsinki, Finland. For a scheme providing ca. 50% of all electricity in the city through self-consumption of variable renewables, power-to-heat with thermal storage could absorb all the surplus production. A significant reduction in the net load magnitude was obtained with shiftable loads.

Investments to both power-to-heat and load shifting with electric heating and commercial refrigeration have a positive net present value if the resources are controlled cost-optimally.

### **Keywords**

Power-to-heat; demand-side management; urban areas; photovoltaics; wind; optimal control

### **Nomenclature**

#### *Symbols*

$k$  time step

$M$  large positive real number

$m$  mass

$n$  natural number

$P$  power, production

$S$  storage state-of-charge

$Q$  consumption

$T$  temperature

$y$  binary variable

$\varepsilon$  small positive real number

$\pi$  price

#### *Abbreviations*

acc. accumulation

CHP combined heat and power

COP coefficient of performance

CR commercial refrigeration

DH district heating

DHW domestic hot water

DSM demand-side management  
DSO distribution system operator  
EB electric boiler  
EH electric heating  
FIT feed-in tariff  
HOB heat-only boiler  
HP heat pump  
MILP mixed-integer linear program  
NPV net present value  
O&M operations and maintenance  
P2H power-to-heat  
PV photovoltaics  
SI Supplementary Information  
SOC state-of-charge  
TES thermal energy storage  
VAT value added tax  
VRE variable renewable electricity  
V2G vehicle-to-grid

*Subscripts*

*110* 110 kV  
*acc* accumulation  
*boiler* boiler  
*discharge* discharge

<i>dist</i>	distribution
<i>e</i>	electricity
<i>H</i>	high
<i>h</i>	heat
<i>init</i>	initial
<i>j</i>	summation index
<i>k</i>	time step
<i>max</i>	maximum
<i>network</i>	network
<i>orig</i>	original
<i>R</i>	return
<i>S</i>	supply, shiftable
<i>spot</i>	spot (day-ahead) market
<i>sto</i>	storage
<i>surplus</i>	surplus
<i>tax</i>	tax
<i>wind</i>	wind

## 1. Introduction

Urban areas will be increasingly important in climate change mitigation as they represent around two-thirds of all primary energy demand and related CO<sub>2</sub> emissions, and the world is rapidly urbanizing [1]. Moreover, urbanization provides opportunities for low-carbon development in developing countries [2]. Employing renewable energy in large scale in cities would therefore have a major impact to climate change mitigation. Many cities have already set ambitious emissions targets: e.g. Helsinki, the capital of Finland, aims at carbon neutrality by 2050 [3] and Copenhagen, Denmark already by 2025 [4], even though both cities still meet most of their heat demand with combined heat and power (CHP) plants run with fossil fuels.

Photovoltaics (PV) is very suitable for renewable energy production in urban areas, especially on building roofs [5]. Shading and limits on rooftop area may limit the potential to around 10–20% of the annual demand in city centers, but suburban areas with low-rise buildings may produce over 100% of their demand [6]. Overall, rooftop PV can make a significant and cost-effective contribution to meeting urban electricity demand, and could provide up to 32% of the worldwide urban demand by 2050 [1]. While in-zone wind energy in the built environment may be marginal [7], close-by wind farms could provide major impacts [8], in particular when integrated to a larger grid serving the city [9]. However, the variability and uncertainty of these variable renewable electricity (VRE) sources presents a major challenge to the flexibility of energy systems [10]. The electricity demand side in urban areas could offer new flexibility opportunities [1], e.g. through control of electricity consumption (demand side management, DSM) [10] and energy storage [11]. Flexibility in the demand side would also be useful to combining VRE with low-carbon baseload electricity production with nuclear power plants [12]. DSM in urban areas is already being implemented at large scale, e.g. for peak load reduction in Beijing [13].

Electric heating, cooling, and shiftable appliances, such as dishwashers, offer high DSM potential while interfering only slightly with human or business activities [10]. In addition to employing the thermal masses of distributed electric heating or cooling devices [14] or incorporating thermal storage (TES) to these processes [15], thermal loads can be leveraged for power system flexibility for better VRE integration with power-to-heat (P2H) strategies [16]. That is, other sources of thermal energy in e.g. district heating (DH) are replaced with electric boilers (EB) or heat pumps (HP) operating with surplus VRE, possibly employing thermal energy storage. The produced heat would then be clean and renewable, contrary to conventional heat production with fossil fuels. The EU energy efficiency directive calls for a

renewable share in DH production [17]. While this could be achieved with renewable heat production with e.g. biofuels or solar heating [17], providing it with P2H from surplus VRE would also increase the renewable share of electricity production [18]. P2H with low-cost surplus VRE [6] could also be highly profitable to DH companies which operate in natural monopolies [19]. Heat pumps with thermal storage have been found especially beneficial with a high potential for reducing CO<sub>2</sub> emissions and fossil fuel use at a lower cost than other energy storage schemes [20]. However, regulatory barriers such as electricity taxes may hinder the economic potential of P2H [21].

The potential of DSM and P2H in providing flexibility for VRE integration in urban areas has received some attention. The focus has mostly been on P2H strategies, including distributed electric heat pump schemes [9], and integration of heat pumps or electric boilers to urban DH networks. Our group has previously studied P2H in urban DH systems with temporal simulations [18]. Shiftable loads have also been simulated with P2H [22]. The operation of conventional plants with P2H and shiftable loads has also been studied [23]. Spatio-temporal simulations have also been done to identify bottlenecks in the electrical grid considering high-voltage transmission [6], and also medium-voltage distribution feeders [22]. Urban multi-energy networks consisting of electricity and heat have also been studied [8]. Gas and cooling networks have also been included to the spatio-temporal simulations in addition to electricity and heat [24]. The aforementioned papers have employed rule-based controls, instead of optimal control studied here. Optimal control of CHP plants and P2H has also been studied [25], without including DSM.

Li et al. have studied optimal operation of P2H with heat pumps and TES in an integrated urban electricity and DH system with VRE and CHP production [26]. Nielsen et al. have presented a stochastic optimization model to evaluate EBs and HPs in an urban DH system in Denmark with electricity price affected by wind power [27]. The combined effect of plug-in hybrid electric vehicles and thermal storage has also been studied [28]. Peak shaving and load shifting of domestic, commercial and industrial loads for wind integration has been studied in [29], however with rough literature-based approximations on the shiftable and curtailable proportions of the load. An analysis of load shifting and vehicle-to-grid (V2G) has also been conducted [30], limited to residential loads and relying on generalized assumptions on the properties of controllable devices.

In addition to the urban level considered in this paper, DSM and P2H have been studied at the national level e.g. in Finland [12], Denmark [31] and Germany [32], and in the whole European Union [33]. Electricity demand side measures and P2H have also been widely studied at the level of single buildings and microgrids. The microgrid-level studies include e.g. optimal day-ahead market bidding with DSM and power plants [34], optimal sizing of distributed energy resources [35], optimal management of shiftable loads with wind and PV [36] and aggregated management of shiftable loads and electricity storage [37]. Examples of single-building level studies include robust optimal control of loads with PV [38], optimal and rule-based control of a heat pump with storage, batteries and shiftable loads with PV [39], comparison of TES systems for residential micro-CHP plants [40], a smart home energy management system with shiftable loads and storage [41], optimal control of a heating and cooling system including a heat pump with storage [42] and control of electric loads and air conditioning in residential buildings [43]. Urban-level studies can provide insight on the potential of the flexibility technologies in “hot spots” of future energy systems, driving the focus of the more detailed and technical studies at the micro-level to the most viable technologies.

This paper presents improved models to assess the technical and economic potential of optimally controlled DSM and P2H to provide flexibility for large-scale VRE integration in urban areas. Recent reviews on energy system models for renewable energy integration [44], district heat systems [45], and urban energy systems [46] list several well-established models for operation optimization of interconnected urban electricity and heat systems. However, they are not suitable for this purpose, as they either do not include DSM, or the control is not mathematically optimal. An example is energyPRO [47], which doesn't include shiftable loads and uses fixed priorities in the control algorithm [48]. The assessment of technical potential is here based on optimal matching of VRE production and load, and the economic potential is based on maximizing the net cash flow of operation. The main P2H strategy employed considers conversion of excess VRE power to heat, e.g. connected to a district heating network as in case of Helsinki, but also thermal energy storage. The DSM sources comprise general loads shiftable for  $n$  hours, and distributed thermal storage with electric heating.

We apply the models to a case study in Helsinki, which is a mid-sized (population 0.6 million) and high-latitude (60 °N) city. Good-quality and diverse input data is available for Helsinki, enabling a detailed analysis. District heating covers over 90% of the heat load in the city [49]. The included DSM measures comprise refrigeration loads in households, grocery stores and warehouses, and electric heating of buildings with resistance heaters and heat pumps. Shiftable

wet appliances in households, namely dishwashers, washing machines and tumblers, are included as well. Quite unique empirical time series are employed for the DSM analysis. The analysis is conducted over a period of three years 2013-2015, and the year 2050. An investment analysis is also conducted. Both PV and wind power are studied. Helsinki is located on the coast with a significant local wind resource which remains still untapped [8]. The PV potential of the rooftops in Helsinki is significant as well: 800 GWh annually [50]. While unsubsidized PV has been found uneconomical in Finland in single detached houses with district heating, the economics could be alleviated with electric heating, DSM and distributed energy storage, as well as community projects which could be done in e.g. housing cooperatives in cities [51]. Moreover, service sector buildings, abundant in cities, have high self-consumption potential and can install large PV systems at low unit cost.

This paper adds new information to the previous literature by analyzing combinations of P2H and DSM strategies with optimal control, providing an assessment of their full potential. The flexibility capabilities of the DH network are analyzed in detail under dynamic boundary conditions.

## **2. Data and methods**

The models presented in this paper solve sequential optimal control of the energy system for a given time series of input data, employing a mathematical model of the energy system. Figure 1 shows a schematic of the modeling principle employed here. In the next chapters, the sub-models are described in more detail. More information about the input data is presented in Supplementary Information (SI).

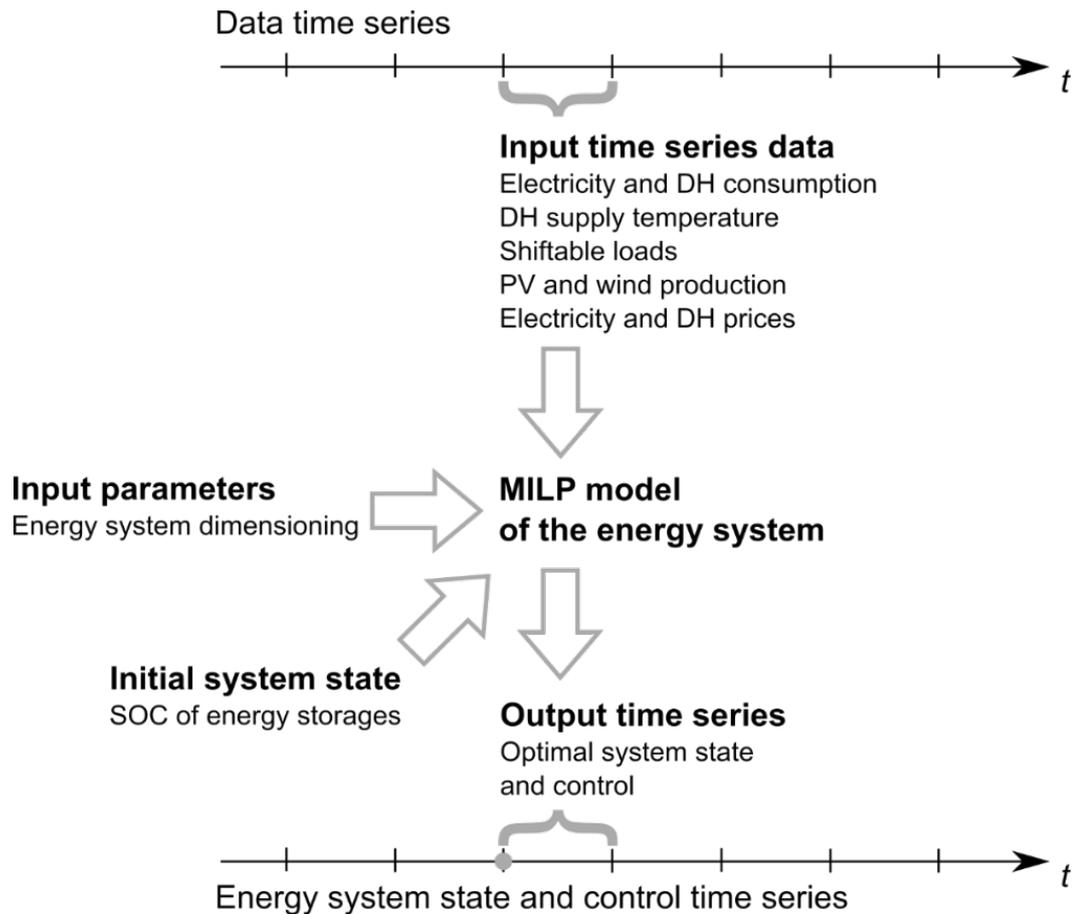


Figure 1. Schematic of the modeling principle.

### 2.1. Shiftable load data and modeling

A generic bottom-up method to construct time series of shiftable loads is employed here with data applicable to the case study of Helsinki. The shiftable loads considered here are electric heating of buildings with electric boilers and heat pumps, refrigerators and freezers in households and grocery stores, freezer warehouses, and dishwashers, washing machines and tumblers in households. These loads have a high potential for DSM and can be controlled with minimal impacts on human or business activities.

The loads are modeled as aggregate time series shiftable for maximum  $n$  hours, except for the electric heating with storage, which is modeled separately. The loads are assumed to be linear systems requiring the same total amount of energy whether shifted or not, and continuously controllable at the aggregated level. The changes in losses or coefficients of performance (COP) in thermal loads due to load shifting are neglected here. The assumption of continuous

control is a good approximation as many of the loads can be controlled in a stepless fashion at the unit level, and the size of the population is large.

Figure 2 shows the shiftable load components in Helsinki along with the total power demand. The shiftable loads range from 35 to 350 MW, or 7–50% of the hourly electricity consumption. Their share of the total annual consumption is 20%. The time series of shiftable loads are based on empirical consumption data, literature values on the ability of the loads to shift their consumption and statistical data. See Supplementary Information for details.

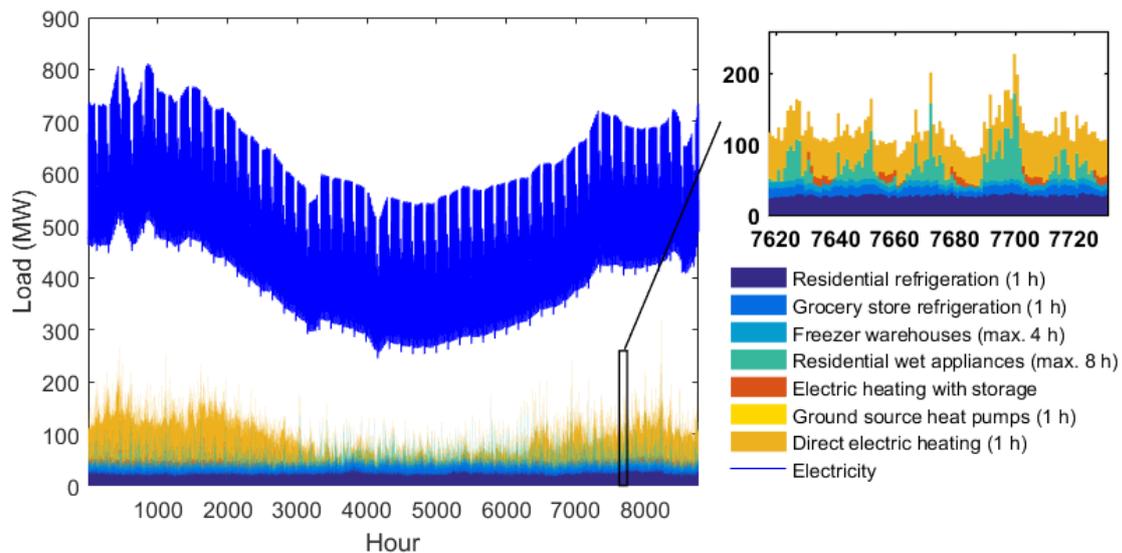


Figure 2. Electricity load in Helsinki with the shiftable components. The duration that a load can shift its consumption is indicated in the legend. Electric heating data is for the year 2013.

Ventilation, air conditioning and melting of snow and ice in gutters and rooftop drains could also be significant sources of shiftable load in Finnish conditions [52]. Based on building areas [53], ventilation requirements [54] and the dimensioning power of these systems [52], the electric power of each of these categories in Helsinki is in the order of 100 MW. However, they are not considered here as limited data is available on the implementation details, energy consumption and control. Moreover, district cooling is prominent in Helsinki [55]. The five water towers [56] and one wastewater treatment plant [57] in Helsinki can only contribute less than 1 MW to load shifting [58], and are thus not considered here. Distributed heating with fuels consumes almost as much energy as electric heating in Helsinki [49], and heating electrification could also bring significant extra shiftable load in the future.

## 2.2 Power-to-heat, heat accumulation in networks, and thermal storage

In the P2H scheme employed here, surplus VRE is converted into heat and distributed through a district heating network to the end-users. The storage capacity of the piping network can be utilized for heat accumulation, and additionally separate water tank thermal storages (TES) can be used. The P2H conversion is done with electric boilers (EB,  $COP \approx 1$ ) or heat pumps (HP,  $COP \approx 3$ , neglecting minor variations with temperature [59]). Throughout this paper, the heat pumps and electric boilers are dimensioned to the VRE nameplate electric power with the HP covering 50% of the maximum produced heat power.

No ramping or minimum load constraints are required for EBs or HPs. The power of EBs can be adjusted between zero and full load within minutes or even seconds [27]. However, EBs larger than several MWs with electrode heating elements have a minimum load of 10–20% [60]. In this work, smaller resistance heater EBs (up to 1–2 MW) are used at least to the extent that they cover the region from zero to minimum load of the large EBs. Large HPs in the MW range can be controlled from cold start to full load in typically less than five minutes [60]. However, there is a lead time before the optimal COP is reached in a cold start [21], and continuous cycling may cause significant wear to the HPs [61]. Study of these effects is left for further work. The maximum outlet temperature of heat pumps used for district heating is 90 °C [62].

The DH network supply temperature can be increased by up to 15 °C for accumulation, while remaining below 120 °C [63]. The volume of the DH network in Helsinki is  $m_{network} = 68,095 \text{ m}^3$  [64], resulting in  $S_{max} = 1.2 \text{ GWh}$  of heat storage capacity in the whole network. The full storage capacity is used in the simulations, leading to possible violation of the 120 °C upper limit during a negligible <1.5% of the simulation periods. Effect of accumulation on DH network losses, and the energy consumption of DH pumps are neglected in this paper. Furthermore, modeling mass flows in the DH network is out of the scope of this work. This may somewhat overestimate the storage capacity and the maximum charging power available for accumulation as a volume equivalent to the whole supply piping is assumed to circulate through the P2H plants during a 1-hour time step.

For thermal storage, a plug-flow model is used (Fig. 3). With well-designed diffusers at the inlets and outlets, a high level of stratification can be maintained in large thermal storages [63], making the plug-flow model empirically valid [65].

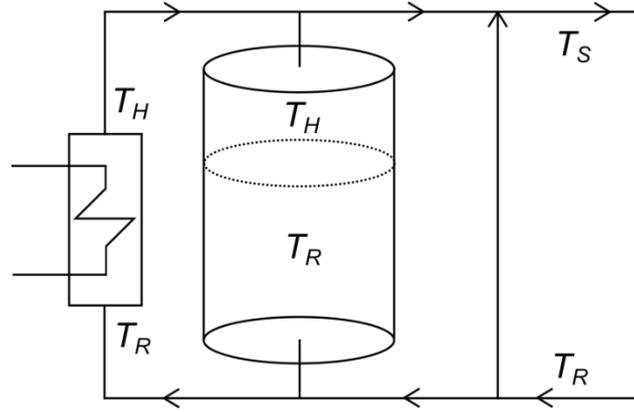


Figure 3. Plug-flow TES model.

A constant return temperature  $T_R \approx 35 \text{ }^\circ\text{C}$  is assumed in the network [63]. The TES is operated at a constant  $T_H = 90 \text{ }^\circ\text{C}$ : it can be charged with a heat pump throughout the year and it can be unpressurized, reducing cost [63]. 642 MWh corresponds to a typical  $10,000 \text{ m}^3$  TES with these temperatures. The large storages are well insulated with a typical heat loss of only  $10 \text{ W/m}^2$  in short-term use [63], resulting in negligible total losses in the order of 10 kW with the storage sizes considered here.

### 2.3 Optimal control of shiftable loads and power-to-heat

Optimal control of the shiftable loads and P2H is solved sequentially over 24-h horizons in order to study the potential of these flexibility sources with the best possible control strategy. The 24-h horizon is realistic in terms of the forecast availability and fits with the day-ahead electricity market. The optimization objectives are minimization of residual load magnitude and maximization of net cash flow. The optimization is formulated as a mixed-integer linear problem, which can be solved rapidly and allows to analyze a large range of different system configurations and VRE penetration levels.

Perfect information of the total and shiftable electricity demand, heat demand, VRE production, and market price over the horizon is assumed in order to study the full achievable potential. For actual implementation, forecasts would be employed. Moreover, the market actor considered here is assumed a price taker. The system-level controls considered here could be implemented with load aggregators that accept the control commands in terms of power and control the individual loads accordingly [66].

#### 2.3.1 Load-VRE matching optimization

The shiftable loads and P2H are employed to optimally match the city-level electricity consumption with VRE production. This gives the maximum technical potential of the flexibility sources for balancing VRE production. The absolute value of the residual load is minimized over the optimization horizon:

$$\min \sum_{k=1}^{24} |P_{VRE,k} - Q_{e,k}|. \quad (1)$$

The constraints of the mixed-integer linear program (MILP) in Eq. (1) are presented in Table 1. The conditional constraints (10) are presented in conditional form for clarity. Transforming them to a linear formulation gives rise to binary variables in the problem. See Supplementary Information for the full linear formulation. The power and storage capacities corresponding to flexibility options not included in the simulated cases are constrained to zero. The solver CPLEX [67] for MATLAB was used in this work, with one sequential run over 3 years taking 5–16 seconds with an Intel Xeon E3-1230 V2 3.3 GHz processor, depending on the VRE magnitude and flexibility options included.

Table 1. Constraints for the load-VRE matching optimization problem. The constraints are valid over the whole optimization horizon: for all  $k = 1, \dots, 24$ .

P2H in normal network operation and TES discharge fulfill current surplus heat demand (not fulfilled by network accumulation discharge)	$P_{HP,k}COP + P_{boiler,k} + P_{discharge,TES,k} \leq Q_{h,surplus,k}$	(2)
Heat pumps can run in normal network operation when $T_S \leq 90$ °C	$P_{HP,k} \leq P_{max,HP,k}, P_{max,HP,k} = \begin{cases} M, T_{S,k} \leq 90 \text{ °C} \\ 0, T_{S,k} > 90 \text{ °C} \end{cases}$	(3)
Heat pumps can accumulate network up to 90 °C	$P_{HP,acc,k}COP \leq cm_{network} \max(\min(T_{S,k} + 15\text{°C}, 90 \text{ °C}) - T_{S,k}, 0)$	(4)
Installed heat pump capacity	$P_{HP,k} + P_{HP,acc,k} + P_{HP,TES,k} \leq P_{HP,capacity}$	(5)
Installed boiler capacity	$P_{boiler,k} + P_{boiler,acc,k} + P_{boiler,TES,k} \leq P_{boiler,capacity}$	(6)
TES can be discharged when $T_S \leq 90$ °C	$P_{discharge,TES,k} \leq P_{discharge,TES,max,k}, P_{discharge,TES,max,k} = \begin{cases} P_{TES,max}, T_{S,k} \leq 90 \text{ °C} \\ 0, T_{S,k} > 90 \text{ °C} \end{cases}$	(7)
TES charging capacity	$P_{HP,TES,k}COP + P_{boiler,TES,k} \leq P_{TES,max}$	(8)
State of accumulated network storage	$S_{k+1} = S_k - (Q_{h,k} - Q_{h,surplus,k}) + P_{HP,acc,k}COP + P_{boiler,acc,k}$	(9)
Accumulated heat takes precedence in fulfilling heat demand (see SI for linear formulation)	If $S_{k+1} > 0, Q_{h,surplus,k} = 0$	(10)
Initial network storage SOC	$S_1 = S_{init}$	(11)
Storage capacity in network	$0 \leq S_k \leq S_{max}$	(12)
State of TES	$S_{TES,k+1} = S_{TES,k} + P_{HP,TES,k}COP + P_{boiler,TES,k} - P_{discharge,TES,k}$	(13)
Initial TES SOC	$S_{TES,1} = S_{TES,init}$	(14)
Storage capacity of TES	$0 \leq S_{TES,k} \leq S_{TES,max}$	(15)
Shiftable loads can be shifted for max. $n$ hours	$\sum_{j=k-n}^{k+n} P_{S,n,k,j} = P_{S,n,orig,k}, \forall n \in \{1,4,8\}$	(16)

---

Aggregate dynamics of distributed heat storage in building electric heating

$$E_{sto,k+1} = E_{sto,k} + P_{sto,k} - \frac{1}{\eta_{sto}} P_{sto,h,k} \quad (17)$$

Initial heat storage SOC

$$E_{sto,1} = E_{sto,init} \quad (18)$$

Distributed storage capacity

$$0 \leq E_{sto,k} \leq E_{sto,max} \quad (19)$$

Electricity consumption after DSM and P2H

$$Q_{e,k} = Q_{e,orig,k} + \sum_{n \in \{1,4,8\}} \sum_{j=k-n}^{k+n} (P_{S,n,j,k} - P_{S,n,k,j}) \quad (20)$$

$$+ P_{HP,k} + P_{boiler,k} + P_{HP,acc,k} + P_{boiler,acc,k}$$

$$+ P_{HP,TES,k} + P_{boiler,TES,k} + P_{sto,k}$$

Surplus heat demand is non-negative and can't exceed total heat demand

$$0 \leq Q_{h,surplus,k} \leq Q_{h,k} \quad (21)$$

P2H powers and load shifts are non-negative

$$P_{HP,k} \geq 0, \quad (22)$$

$$P_{boiler,k} \geq 0 \quad (23)$$

$$P_{S,n,k,j} \geq 0, \forall j = 1, \dots, 24, n \in \{1,4,8\} \quad (24)$$

Storage charge and discharge powers are non-negative and up to the total capacity can be charged during the 1-h time step

$$0 \leq P_{HP,acc,k} \leq S_{max}/COP \quad (25)$$

$$0 \leq P_{boiler,acc,k} \leq S_{max} \quad (26)$$

$$0 \leq P_{HP,TES,k} \leq P_{TES,max}/COP \quad (27)$$

$$0 \leq P_{boiler,TES,k} \leq P_{TES,max} \quad (28)$$

$$0 \leq P_{discharge,TES,k} \leq S_{TES,max} \quad (29)$$


---

### 2.3.2. Cost-optimal market participation

Cost-optimal operation of DSM and P2H resources with VRE plants is solved to evaluate the effect of actual electricity and heat prices on the use of DSM and P2H for VRE balancing. As the load-VRE matching optimization is done in terms of energy only, it does not consider the loss of exergy in power-to-heat. Studying cost-optimal control can reveal whether the exergy loss affects the results of marginal cost optimization through the price difference of electricity and heat. The profitability of the DSM and P2H investments is also studied.

In practice, individual companies optimize their operations aiming to maximize their profits. The technical system comprising P2H, DSM and VRE studied in this paper does not correspond

directly to any established market actor in Finland. Hence, a hypothetical market actor is considered here, which

- owns and operates the wind power installations and receives the produced electricity for a zero marginal cost;
- owns and operates PV installations and receives the produced electricity for zero marginal cost, or buys surplus PV electricity after self-consumption for the price of  $\pi_{PV,surplus}$ ;
- owns and operates heat pumps, boilers and thermal storages connected to the district heating system, and pays electricity tax  $\pi_{e,tax}$  for their consumption as required in Finland [68];
- has a monopoly on the heat accumulation in the DH network in the city and priority on heat production to it in its normal operation, receiving a price  $\pi_h$  for the heat consumption it fulfills;
- sells and buys electricity to the day-ahead spot market for the hourly stock market price  $\pi_{e,spot}$ ;
- sells wind power to the day-ahead spot market for  $\pi_{e,wind}$ ;
- controls the shiftable load population and receives a constant price of  $\pi_{DSM}$  for the electricity consumed by the shiftable loads;
- pays distribution costs for wind and P2H systems connected to the 110 kV distribution network  $\pi_{e,dist,110}$  and, in case it owns them, PV systems connected to the low-voltage network.

The market actor maximizes its net cash flow over the optimization horizon:

$$\begin{aligned}
\max \sum_{k=1}^{24} & \left[ \pi_{e,spot,k} P_{e,spot,net,k} + \pi_{wind,k} P_{wind,spot,k} - \pi_{PV,k} P_{PV,k} - \pi_{e,dist,110,k} P_{wind,k} \right. \\
& - (\pi_{e,tax} + \pi_{e,dist,110,k}) (P_{HP,k} + P_{boiler,k} + P_{HP,acc,k} + P_{boiler,acc,k} \\
& + P_{HP,TES,k} + P_{boiler,TES,k}) \\
& + \pi_{h,k} \left( \underbrace{Q_{h,k} - Q_{h,surplus,k}}_{\text{Accumulation discharge}} + P_{discharge,TES,k} + \underbrace{P_{HP,k} COP + P_{boiler,k}}_{\text{Heat produced to direct consumption}} \right) \\
& + \pi_{DSM} \left( \sum_{n \in \{1,4,8\}} P_{S,n,orig,k} + \sum_{n \in \{1,4,8\}} \sum_{j=k-n}^{k+n} (P_{S,n,j,k} - P_{S,n,k,j}) \right. \\
& \left. + P_{sto,k} \right) \left. \right]. \tag{30}
\end{aligned}$$

The constraints for the optimization problem are the same as in the load-VRE matching problem, with the following modifications. The remaining electricity consumption in the city (20) is replaced with the electricity balance of the market actor:

$$\begin{aligned}
P_{PV,k} + P_{wind,k} & = P_{e,spot,net,k} + P_{wind,spot,k} \\
& + \sum_{n \in \{1,4,8\}} P_{S,n,orig,k} \\
& + \sum_{n \in \{1,4,8\}} \sum_{j=k-n}^{k+n} (P_{S,n,j,k} - P_{S,n,k,j}) + P_{sto,k} \\
& + P_{HP,k} + P_{boiler,k} + P_{HP,acc,k} + P_{boiler,acc,k} \\
& + P_{HP,TES,k} + P_{boiler,TES,k}. \tag{31}
\end{aligned}$$

Wind trading is positive and constrained by available wind power:

$$0 \leq P_{wind,spot,k} \leq P_{wind,k}. \tag{32}$$

As the providers of the load shifting are compensated for the amount of energy available for control instead of the amount actually controlled, the baseline measurement problem [10] is avoided. If load shifting is not used, the load shifting terms are removed from the constraints (31) and the objective function (30). Hence, the market actor does not sell any electricity to the shiftable load consumers in that case.

In case surplus PV after self-consumption is modeled, the electricity consumption of the city is subtracted from  $P_{PV}$ , and  $\pi_{PV}$  is  $\pi_{PV,surplus}$ . In the other case, the actor receives all the PV

production and  $\pi_{PV}$  is the distribution cost in the low-voltage network. The modeling of the surplus PV described above may underestimate the amount of power received by the market actor, as it is determined at a city level instead of at a metering point level employed in practical contracts. However, the actual surplus is sensitive to the distribution of the PV capacity between different consumer groups, which is difficult to estimate in the Finnish case as PV is still a marginal resource [69]. More accurate modeling of the surplus PV production is hence left for further work.

Similarly as in the load-VRE matching problem, the cost-optimal market participation problem is a MILP due to the conditional constraints (10). See Supplementary Information for the full linear formulation. The solver CPLEX [67] for MATLAB was used in this work, with one sequential run over 3 years taking 5–55 seconds with an Intel Xeon E3-1230 V2 3.3 GHz processor, depending on the magnitude of VRE and included flexibility options.

The analysis is conducted both on historical data from 2013–2015, and with simulated 2050 day-ahead electricity market and district heating prices in a scenario with 48% wind power and 12% PV in North Europe (see Fig. 4) [70]. The latter case is included to analyze the effect of market prices affected by a high share of VRE production. The 2050 day-ahead electricity market price has both an increased mean (63.8 €/MWh) and standard deviation (31.7 €/MWh) compared to the 2013–2015 prices (35.6 €/MWh and 13.5 €/MWh, respectively). Moreover, the 2050 day-ahead electricity market price is higher compared to the DH price in the wintertime than in 2013–2015. The increase in the standard deviation of the price can be explained by the higher VRE share. Despite this increase in zero marginal cost production, the mean price is increased as well. This is due to cost and regulatory assumptions in the 2050 market simulations [70]. Coal is completely prohibited, and the cost of natural gas is assumed to increase to 10 €/GJ. The cost of CO<sub>2</sub> emissions is also assumed to increase significantly to 49 €/t. Moreover, a large share of the conventional baseload plants have been assumed decommissioned by 2050. The investment optimization in the simulations has replaced these with VRE and intermediate or peak loads plants with higher marginal cost, such as gas turbines. Furthermore, reservoir hydro power is an important market actor in North Europe. As the water value is determined by the generation replaced by hydropower, it is also increased as the capacity mix becomes more dominated by high marginal cost plants. If baseload plants remain significant in the capacity mix, the prices will be different.

The same technical and economic cases are considered for both periods for comparison, except that a feed-in tariff (FIT) for wind is excluded in 2050. The same distribution costs and taxes, electricity consumption time series and DH consumption model are also used for comparison. Figure 4 shows all the variable costs in the simulation, except  $\pi_{PV,surplus}$  which is left out for clarity. See Supplementary Information for details on the price data.

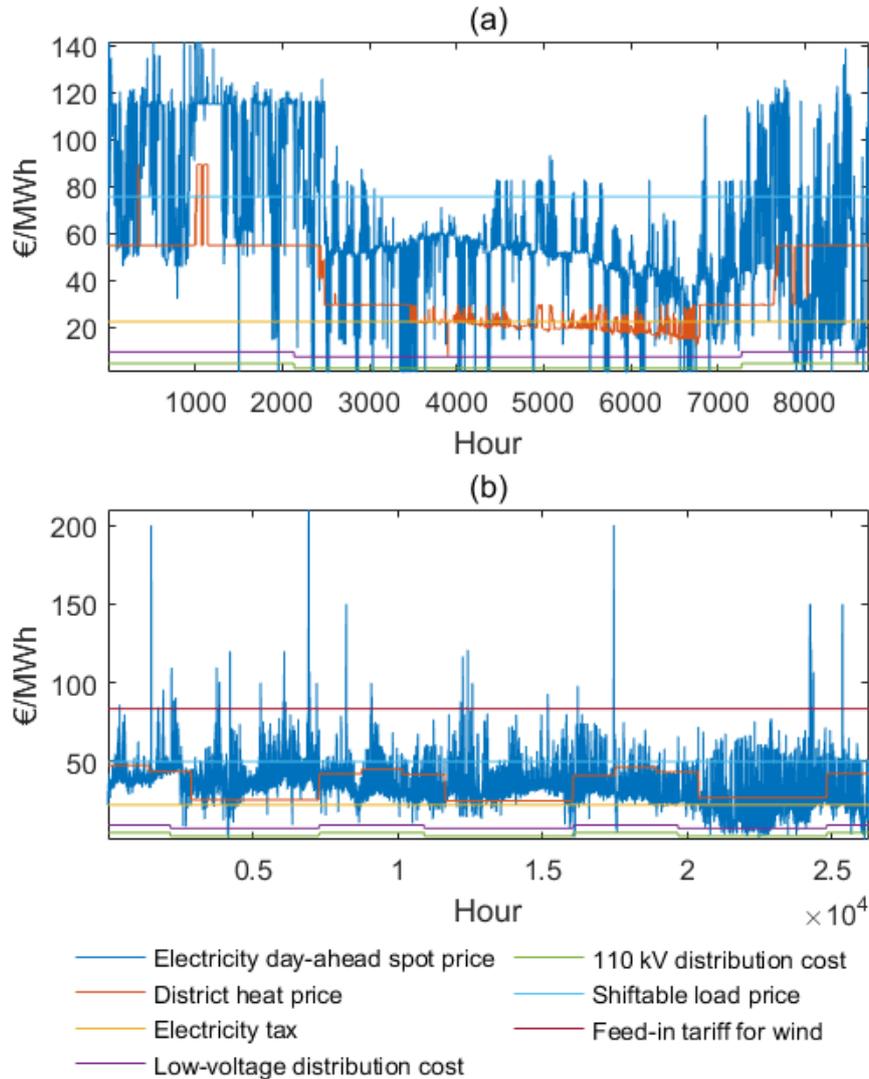


Figure 4. The variable costs in the simulation in (a) 2050, (b) 2013–2015.

Investment and annual fixed costs (Table 2) are taken into account to calculate the net present value (NPV) of the investments required for the flexibility measures. The NPV is calculated from the annual net cash flows with an 8% discount rate and a 20-year project lifetime. The simulation length is repeated to obtain 20-year data. The same investment and fixed costs are used for both 2050 and 2013–2015 for comparison, even though lower investment costs could

be expected in the future. See Supplementary Information for details on the investment and fixed costs.

Table 2. Investment and fixed costs of the flexibility options.

Technology	Investment cost	Fixed cost	Source
Heat pump	680 €kW <sub>th</sub>	5.5 €kW <sub>th</sub> ·year + 10.2 €kW <sub>e</sub> ·year + 23.9 €kVA <sub>r</sub> ·year	Investment and O&M [60], electricity distribution [71]
Electric boiler	145 €kW <sub>e</sub>	1.1 €kW <sub>e</sub> ·year + 10.2 €kW <sub>e</sub> ·year	Investment and O&M [60], electricity distribution [71]
TES	35,260 € + 28 €m <sup>3</sup> + 6.4 €kW <sub>th</sub>	0 €	[63]
Electric heating	0 €	0 €	Own analysis
Residential cold and wet appliances	200,000,000 €	0 €	Own analysis
Commercial refrigeration, freezer warehouses	100 €kW <sub>e</sub>	50 €kW <sub>e</sub> ·year	[72]

### 3. Results

The technical potential of the flexibility sources with different VRE capacities is assessed as a parametric study. The cases with load shifting utilize all the load shifting sources and the DH heat accumulation cases the full heat storage capacity of the whole network. Ten 10,000 m<sup>3</sup> (642 MWh each) TES units are used in the TES cases with a power capacity at maximum value (140 MW per unit [63]). The VRE capacities range from zero to 1400 MW<sub>p</sub> of PV and 1650 MW of wind, limited by available roof and sea area so that shading and wake effects are negligible (see Supplementary Information for details). The capacity factor of PV (0.10) is considerably lower than for wind (0.33): 1,000 MW<sub>p</sub> of PV produces annually 20% of the annual electricity consumption of the city, while 1,000 MW of wind can produce 64%. The results are presented in Fig. 5–7. In all cases studied, all optimizations were either solved to an

exact optimum, or either to an absolute tolerance of  $10^{-4}$  or relative tolerance of  $10^{-6}$ , which is less than the inaccuracy of the model. Hence, the results represent exact upper limits of the technical potential of the flexibility sources with a sequential 24-h control.

Figure 5 shows the surplus VRE production (a) and the corresponding self-use limit curves (b). The VRE surplus percentage is relative to the total annual VRE production. P2H can decrease the surplus VRE very effectively above the self-use limit, acting as a power sink. With simple P2H and without any storage, the VRE surplus is decreased up to 35% at the highest VRE capacity values. DH heat accumulation and separate TES can additionally cut around 3–6%. The effect of load shifting alone is around 2–3%, but rising to 5% with a VRE mix dominated by PV. Load shifting is more effective with PV compared to wind because of the diurnal cycle of PV: some consumption can be shifted from night to daytime to consume surplus, whereas the periods of high wind production can last for several days. Moreover, many of the shiftable loads follow the same diurnal cycle pattern as PV.

The self-use limits in Fig. 5 (b) significantly increase with the P2H schemes, as the DH system is an effective power sink. P2H without any storage can increase the self-use limit by 60–80% compared to no flexibility. With DH heat accumulation the self-use limit can be 2.5-folded and 3–4-folded with TES. P2H schemes with TES can consume all the VRE at low wind capacities up to the maximum PV capacity. P2H with TES is effective in consuming the PV surplus, as it occurs during the daytime and the storage can be discharged at night. This is in contrast to wind, which can have high production levels that last for several days. A longer forecast horizon and possibly more storage capacity could allow for consuming wind with P2H more effectively.

Load shifting can increase the self-use limit by up to 33% without P2H, but it is more effective with PV: the maximum increase occurs with PV only and no wind. With P2H and without storage, load shifting can increase the self-use limit around 14–20%. With P2H and storage, the increase from load shifting is smaller and can even be a decrease with many VRE configurations. This is because the surplus of VRE has not been optimized directly.

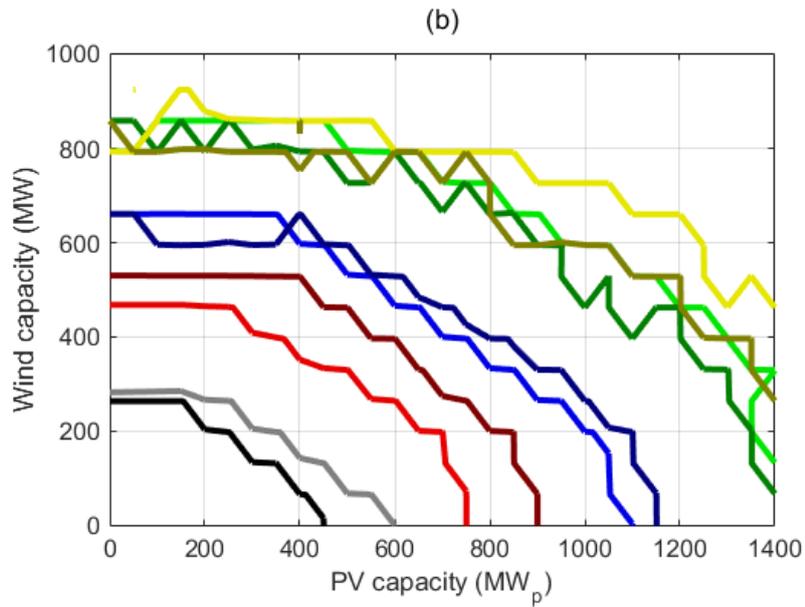
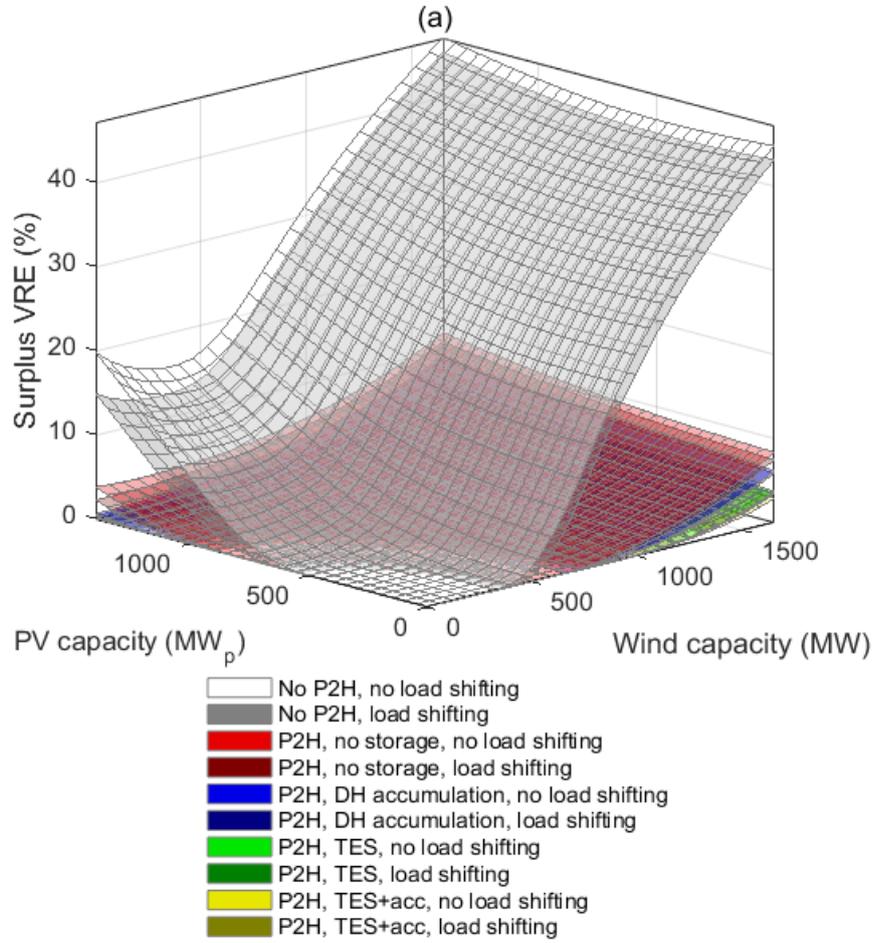


Figure 5. (a) Surplus VRE production, (b) self-use limits. The black line in (b) corresponds to the white surface in (a), other colors are the same.

The share of locally-consumed VRE of all electricity in Helsinki is shown in Fig. 6. The marginal increase of the VRE share vis-à-vis PV or wind capacity is constant up to the self-use limit. Up to 650 MW<sub>p</sub> of PV and 726 MW of wind, the marginal benefit with both PV and wind capacity is over 50% of the maximum marginal benefit below self-use limit. At this point, the VRE share is 51 or 53%, depending on use of load shifting.

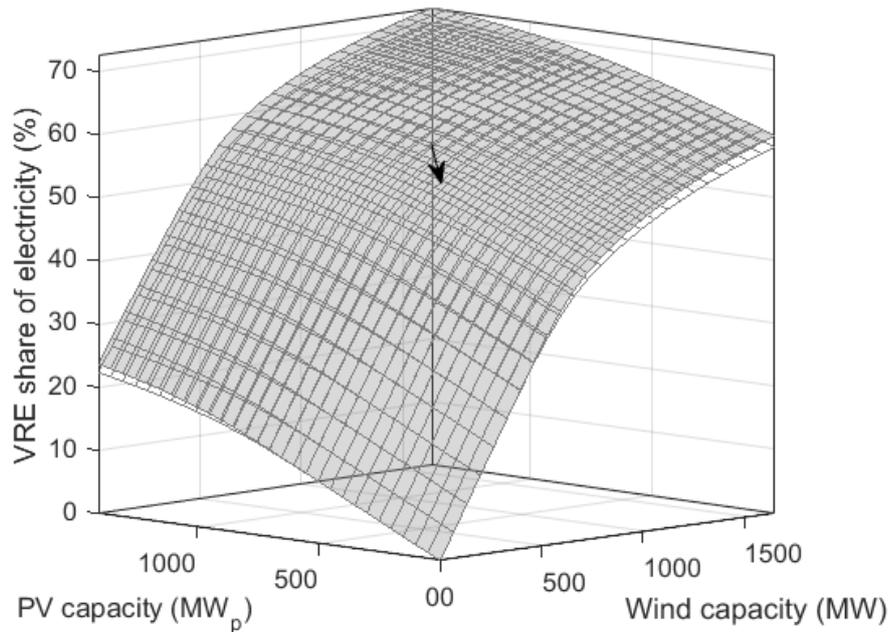


Figure 6. VRE share of electricity consumption. The arrow marks the configuration with 650 MW<sub>p</sub> of PV and 726 MW of wind taken to a detailed analysis.

VRE reaches at highest a 5–10% share of the heat demand through P2H in the PV-dominated configurations (Fig. 7), compared to around 40% with high wind power shares. This is explained by the lower capacity factor of PV and concentration of PV to summertime with low heat demand, whereas wind is more evenly distributed throughout the year with higher production in the winter. At high wind capacities, the share varies 8–10 %-points depending on use of load shifting or storage; at high PV capacities, the variation is only around 2 %-points.

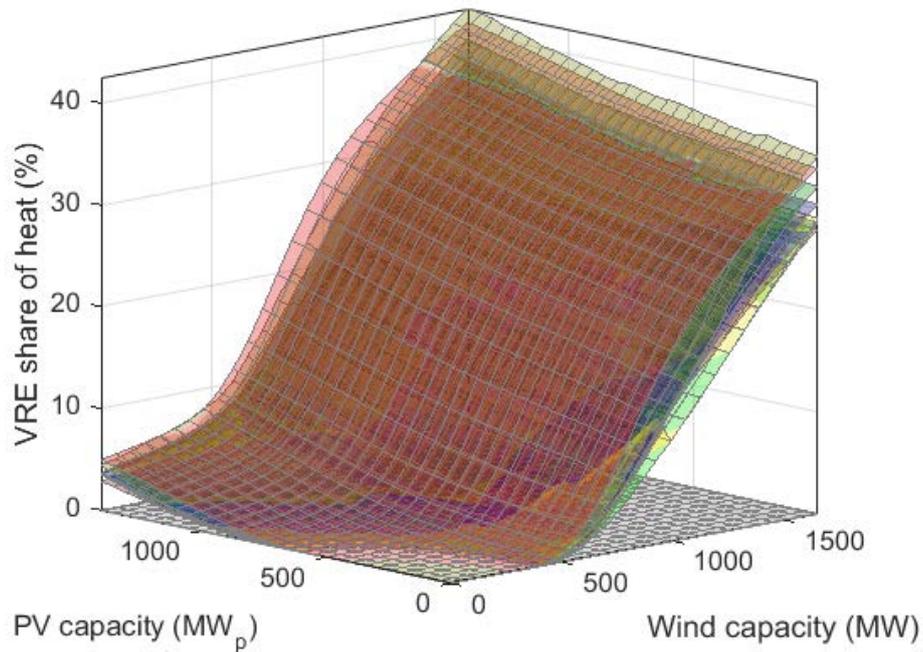


Figure 7. VRE share of district heat consumption in Helsinki.

The VRE configuration with 650 MW<sub>p</sub> of PV and 726 MW of wind described above was taken to a more detailed analysis. Depending on the used DSM or P2H measures, this set-up provides 51–53% of the yearly electricity and 5–11% of the yearly heat consumption in the city, with 0–13% of surplus VRE. Figure 8 shows the duration curves of the electricity net load with load shifting, and P2H with TES. Eight 10,000 m<sup>3</sup> TES units with 60 MW of power capacity per unit (typical values for conventional TES systems [63]) are used in the TES cases, which was found sufficient to consume all the surplus VRE production in sensitivity analysis. Without TES, the DH heat accumulation can absorb almost all surplus VRE with only peak values left over. Accumulation and four 10,000 m<sup>3</sup>, 60 MW TES units are sufficient to deal with all the surplus. The effect of load shifting is observed as decrease in the low consumption and surplus values, and as an 150–200 MW increase in the peak consumption.

To illustrate how the residual of electricity could be covered with the existing power plants in Helsinki, the duration curves of the three CHP plants in the city (see Supplementary Information for details) are also shown for the reference and VRE with P2H, TES and load shifting cases. The curves have been obtained with a rule-based simulation (see Supplementary Information for details) aiming at covering the electricity net load without producing any surplus. The rule-based CHP control is by no means optimal; full optimization of the

conventional plant control with VRE, P2H and load shifting is left for further work. Moreover, in reality, the CHP plants produce surplus electricity that is exported from the city.

In the reference case, the CHP plants are able to cover all the electricity consumption in the city. Plant 1 produces the greatest share (6906 full load hours on average annually) with limited consumption left for the other plants (781 h and 41 h, respectively). In this case, the CHP plants produce 47% of the heat consumption in the city, with full load hours 5120 h, 984 h and 22 h, respectively. The rest would have to be produced with heat-only boilers.

In the case with VRE with P2H, TES and load shifting, the CHP plants are not able to cover the lowest consumption hours because of their minimum loads and limited start-up and shutdown rates. 100 MW of more flexible production could cover those hours. The production of plant 1 is considerably reduced (2456 full load hours on average annually), while the production of the other plants (994 h and 451 h, respectively) increases compared to the reference case, as the net load of electricity is below the minimum load of plant 1 over a significant period of time. In this case, 26% of the heat net load is covered with CHP plants with full load hours 2239 h, 815 h, and 359 h. Only plant 1 would likely be profitable with this control in the reference case with significant decrease in its profitability when VRE and the flexibilities are introduced. Hence, plants better suited for peak load operation could be required to cover the electricity consumption in the city with this VRE and flexibility scheme.

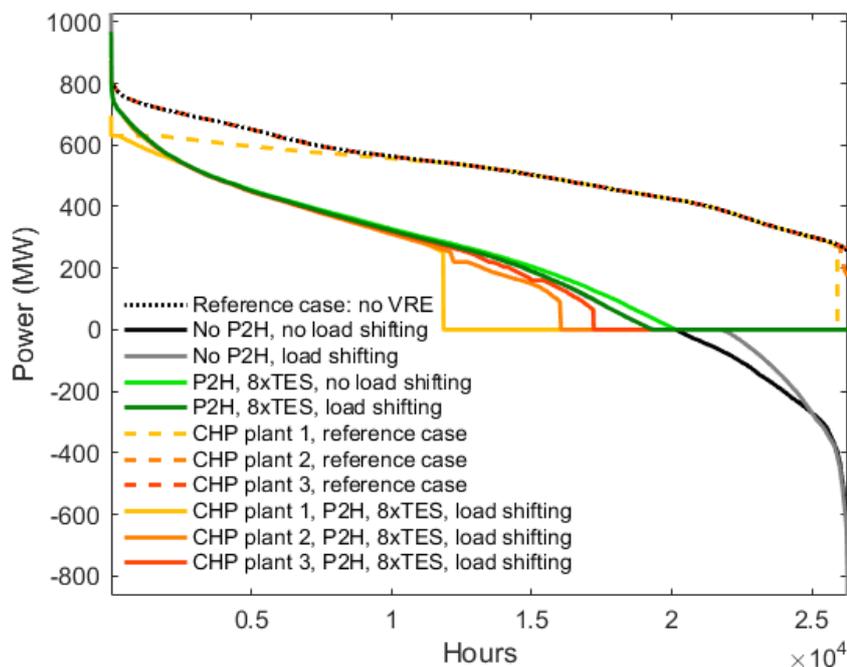


Figure 8. Electricity duration curves with optimal load-VRE matching.

Cost-optimal control is studied with the same VRE configuration studied in the matching analysis: 650 MW<sub>p</sub> of PV and 726 MW of wind. The P2H dimensioning used results in 344 MW<sub>e</sub> of heat pump and 1032 MW of boiler capacity. The thermal storage configurations found sufficient to consume all the surplus VRE in the matching analysis are also employed here along with load shifting. Moreover, load shifting with electric heating (EH) and commercial refrigeration (CR) is studied separately in addition to the whole load shifting potential. Five economic cases are considered: The base case includes electricity tax and distribution cost, FIT is paid for wind production, and all PV production is received by the market actor. Three cases are considered with either FIT, tax or distribution cost removed, and in the fifth case the market actor receives only surplus PV after self-consumption.

In all the studied cases, the optimization problem instances were either solved to exact optimum or either absolute tolerance of  $10^{-4}$  or relative tolerance of  $10^{-6}$ , clearly less than the inaccuracy due to model simplifications. Hence, the results represent exact upper limits of the economic potential of the flexibility sources in day-ahead spot market trading with sequential 24-h optimization horizons. The price-taker assumption can be validated by analyzing the shares of market trading of the market actor. Nonzero values of maximum ratios of buying out of total buying volume of the market range between 1–7% in the studied cost-optimal cases, maximum ratios of selling out of total selling volume 16–42%, and corresponding mean values 1–7% and 3–8%. Even though the maximum shares of selling are quite high, the mean values are low for both buying and selling and the maximum values for buying are low. Hence, the price-taker assumption is plausible.

Figure 9 presents the results obtained with 3-year simulations (2013–2015). All the flexibility measures increase net cash flow (a). The increase with P2H measures is significantly greater than with load shifting. The boiler brings only a little additional benefit when electricity tax is removed, in the other cases its effect is negligible. Similarly, the difference between 8 TES units and 4 TES units with DH accumulation is either small or negligible. No significant synergy benefit from combining load shifting and P2H is observed: their combined effect is approximately the sum of their separate effects. The effects of the flexibility measures are roughly the same in the different economic cases, except the increase with P2H is higher when it is exempt from electricity tax, as expected. The economic cases affect mostly the net cash flow in the case with no flexibility, in a logical fashion.

Load shifting including all the sources has a negative NPV (b) in all the economic cases, whereas load shifting with electric heating and commercial refrigeration has a positive NPV of 74 M€ in all the economic cases. The NPVs of the P2H measures without boiler are highly positive, whereas adding the boiler makes the NPV negative except without distribution cost or electricity tax. It is notable that the boiler costs correspond to resistance boilers; cheaper electrode boilers [60] could be employed to some extent to decrease the cost. The effect of load shifting and P2H combined is approximately the sum of the separate effects also here. The difference between 8 TES units and 4 TES units and DH accumulation is negligible due to the low price of the TES, hence the more difficult to control accumulation is not worthwhile in this case.

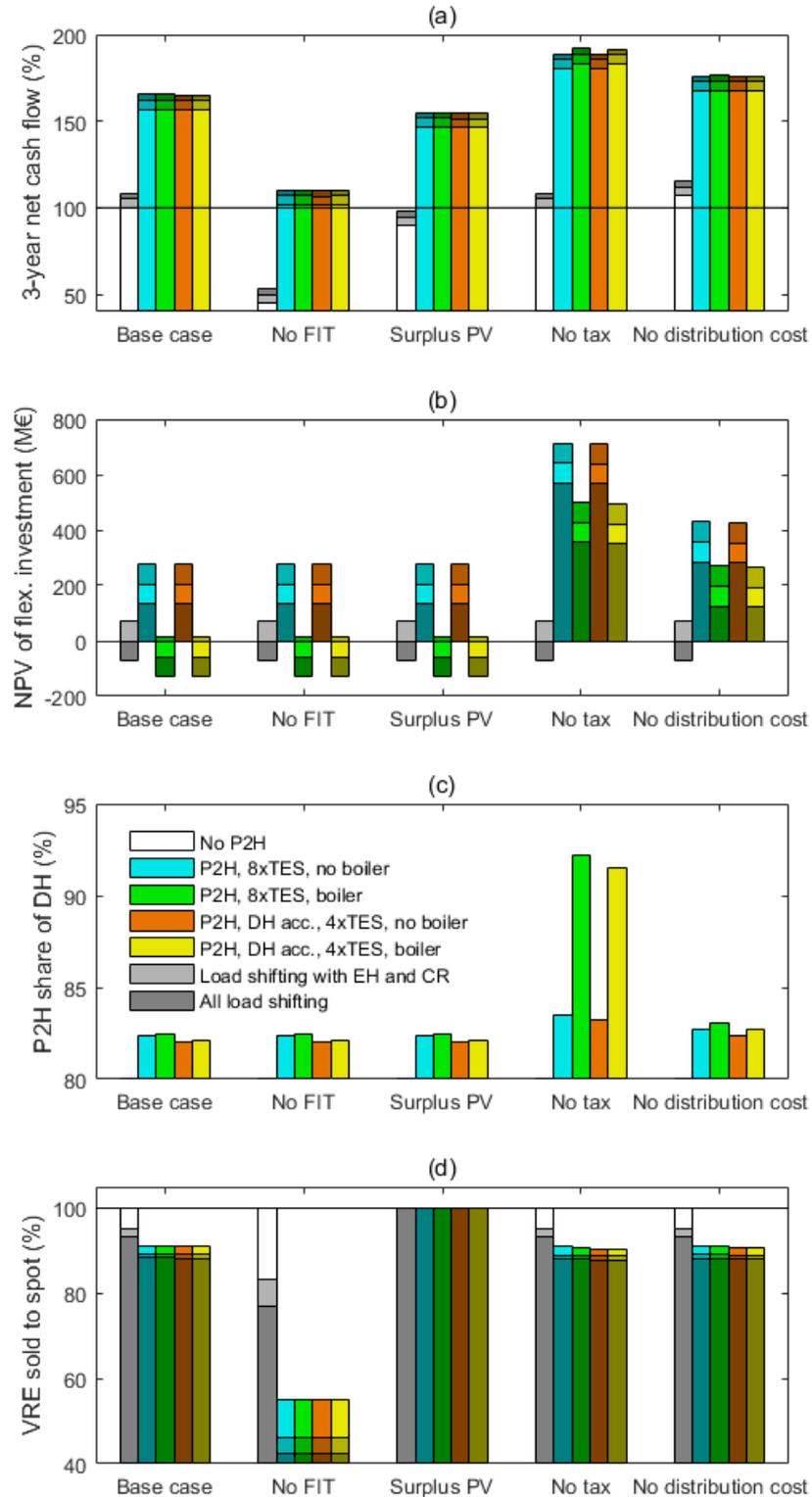


Figure 9. Simulation results for cost-optimal market participation (2013–2015): (a) 3-year net cash flow, excluding investment and fixed costs, relative to no flexibility in the base case (565 M€), (b) net present value of the flexibility investment, (c) share of annual DH produced by P2H, and (d) share of VRE received by the market actor that is sold to the day-ahead spot market.

The P2H shares of district heat (c) are over 80% in all the cases with P2H, indicating that P2H to the DH network is clearly profitable in terms of the marginal cost with the electricity and heat prices during 2013–2015. The effect of the different flexibility configurations or economic cases is limited, except that the boiler increases the share to over 90% when there is no electricity tax for P2H. The shares of VRE received by the market actor that are sold to the spot market (d) are over 87% in all the cases with FIT, indicating the benefit of selling wind power with FIT. In the surplus PV case, the actor receives so little PV that wind dominates and approximately all VRE is sold to the spot market. In the other cases with FIT, the flexibility measures lower the share by 13% at maximum. Without FIT, the flexibility measures have a significant effect, with 58% decrease at maximum.

Because of the favorable electricity and heat prices for P2H especially with heat pumps, the market actor significantly uses electricity bought from the market for P2H. For example, with P2H and 8 TES units, no load shifting and no boiler, the share of VRE of P2H is only 9–10% in the base economic case, and also when taxes or distribution cost are removed. With no FIT, the share rises to 48% as P2H with wind becomes more profitable, and in the surplus PV case the share is negligible as almost all VRE is sold to the market.

Figure 10 shows the net loads of district heating in the reference case with no P2H and two cases with P2H and positive NPV. The first, P2H with 8 TES units and no boiler, is the most profitable of the studied P2H configurations, and is shown here in the economic base case. The same configuration with boiler and without tax is included as well, as the P2H share of DH increases significantly in that case. The P2H systems produce most of the DH. Most of the remaining net load is in the peak hours. Heat pumps are not able to produce the peak load, but including the boiler decreases the peak load by approximately 200 MW.

To illustrate how the cost-optimal P2H operation would affect the rest of the DH system in Helsinki, the CHP plants and heat-only boilers (HOB) were simulated with a rule-based simulation (see Supplementary Information for details), aiming at producing the heat net load without any surplus. The rule-based control is not optimal; full optimization of the plants with VRE, P2H and DSM is left for further work. The duration curves of the CHP plants are shown in Figure 10. The HOBs are not shown for clarity, but together with the CHP plants they are able to cover the heat net load in all the three cases. In the reference case, all the CHP plants have high full load hours: plant 1 6606 h, plant 2 5273 h and plant 3 2432 h. With P2H, the production of the CHP plants is considerably reduced: in the case without boiler, the full load

hours are 951 h, 604 h, and 550 h, and in the final case 424 h, 297 h and 216 h, respectively. This suggests that the CHP plants could not be profitable with the high-capacity P2H schemes considered here.

The effect of the CHP plant and HOB operation on the profitability of the flexibility investment was also considered directly. The plants were assumed to sell the produced electricity to the spot market and the heat at the same DH price as the market actor whose operation was optimized. Plant operating costs were obtained from [73], cost of fuel oil from [74] and ramping costs from [75]. In both the studied P2H cases, the reduced share of the conventional plants turned the NPV of the flexibility investment negative. Even though the P2H schemes are profitable by themselves, their operation with the present DH generation mix in Helsinki would therefore require further optimization. The capacity of the P2H system could be reduced to allow for more CHP production, and replacing some of the CHP capacity with it would be an interesting option.

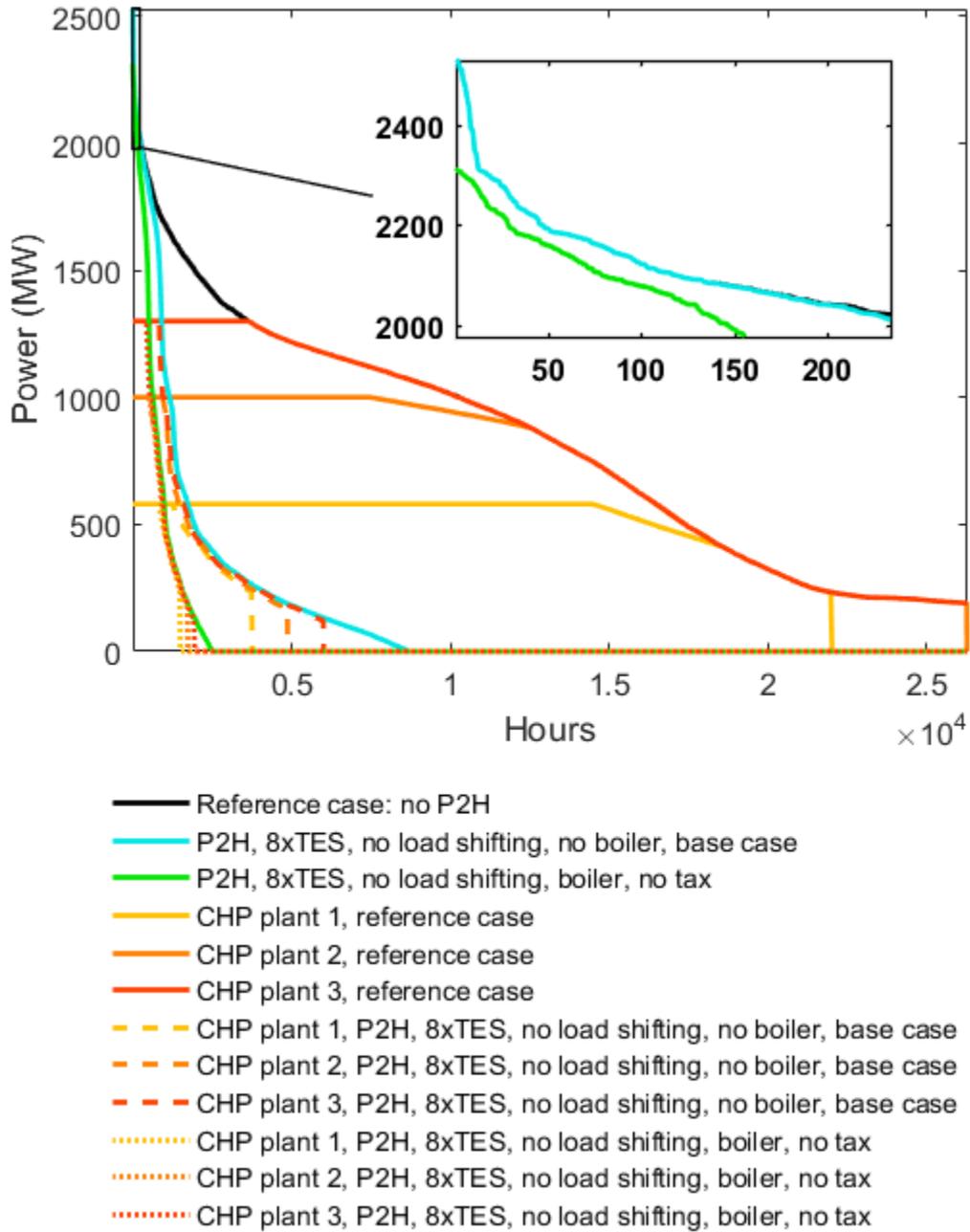


Figure 10. Heat duration curves with cost-optimal operation.

In the Finnish deregulated DH market [19], the DH price can be set by the local DH monopoly, limited by legislation to a reasonable and cost-based level as the DH companies in Finland have dominant market positions [76]. A sensitivity analysis on lowering the DH price was conducted, as the profitability of P2H is based on the high DH price compared to electricity. P2H with 8 TES units, no boiler and no load shifting was considered in the economic case without FIT, and in another with the electricity tax further removed. Figures 11 and 12 show

the net cash flow and NPV, and the P2H share of DH and share of VRE sold to spot market, with varying DH price as ratio of the original price time series.

The DH price could decrease by approx. 10% with tax and 30% without tax without making the NPV of the scheme negative. The P2H share of DH and the share of VRE sold to spot would remain approximately the same. The price drops in the DH price correspond to 17 €/tCO<sub>2</sub>-eq. and 51 €/tCO<sub>2</sub>-eq. increases in carbon price, based on the emissions of the district heat production mix in Helsinki in 2014 [49].

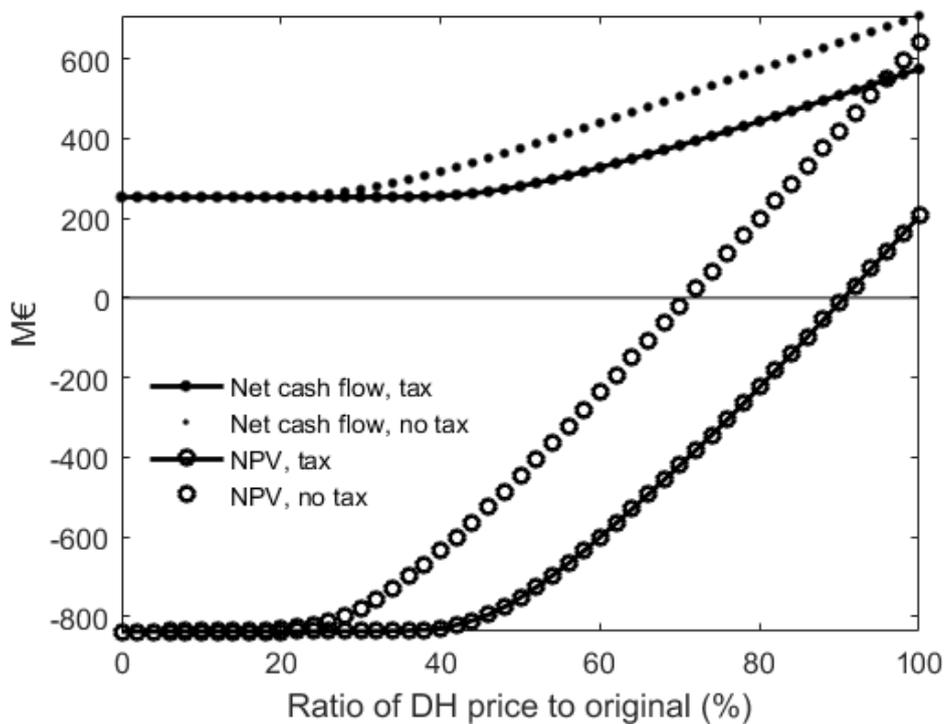


Figure 11. Net cash flow over the 3-year simulation and NPV of the P2H and TES investment.

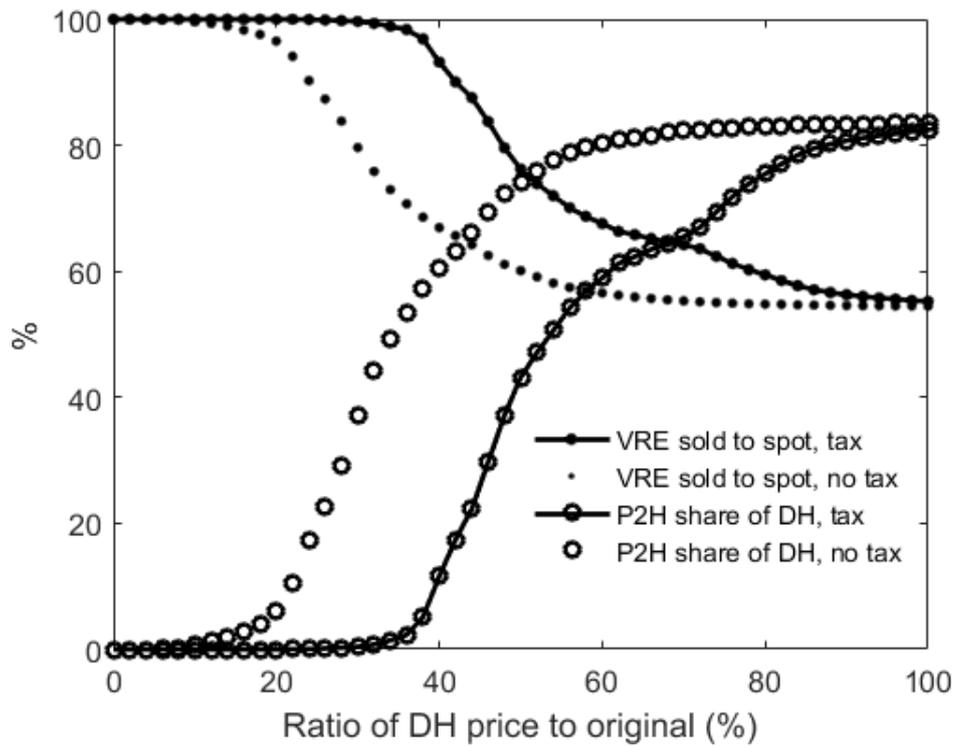


Figure 12. VRE sold to market and P2H share of DH.

Figure 13 presents the results with year 2050 data. All the flexibility sources bring increase in net cash flow (a), P2H more than load shifting. Boiler brings a little extra benefit, and the difference between the two thermal storage schemes is negligible. No significant synergy with P2H and load shifting is observed.

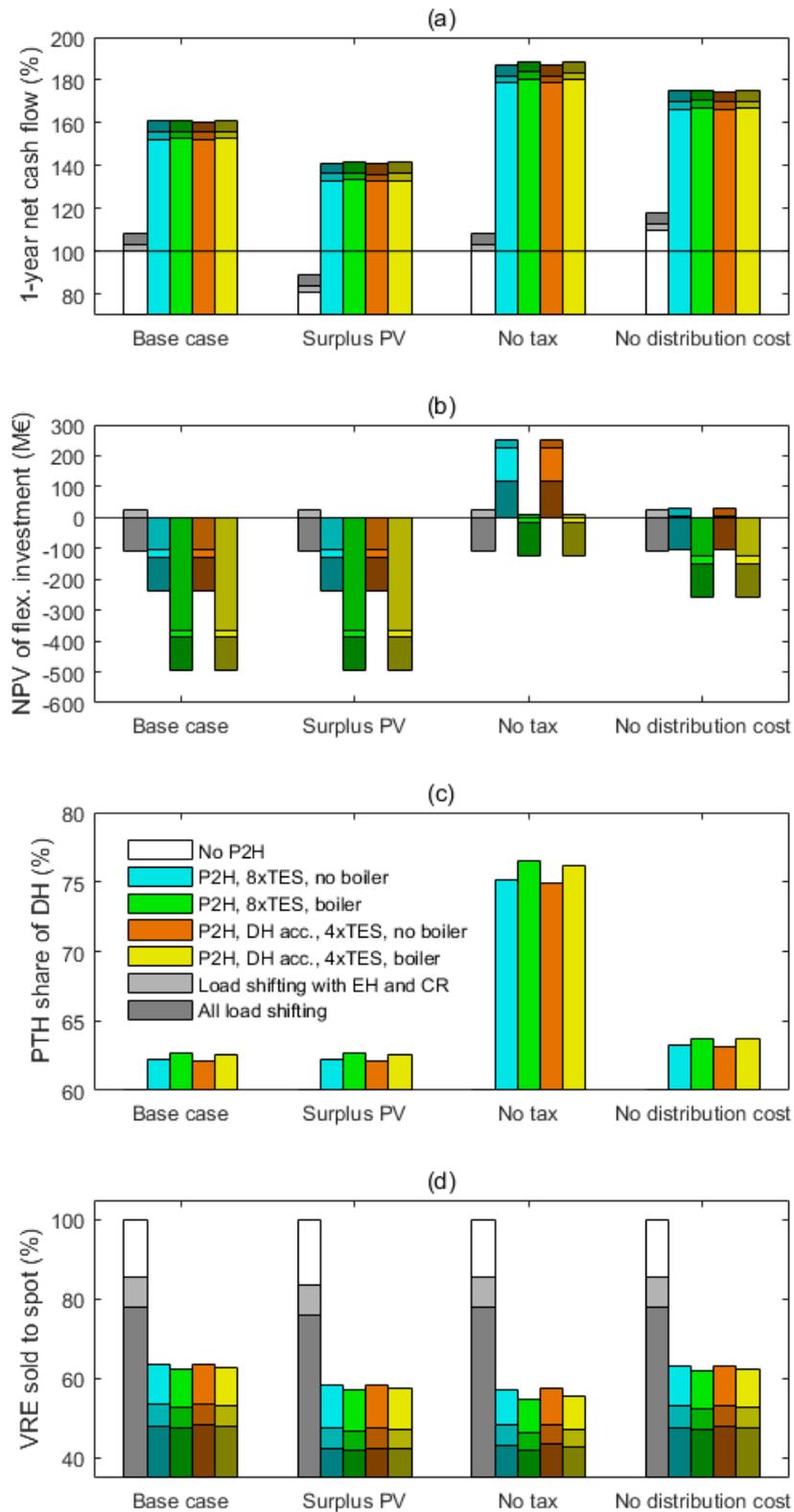


Figure 13. Simulation results for cost-optimal market participation with year 2050 data: (a) 1-year net cash flow, excluding investment and fixed costs, relative to no flexibility in base case (138 M€), (b) net present value of the flexibility investment, (c) share of annual DH

produced by P2H, and (d) share of VRE received by the market actor that is sold to the spot market.

In the cases with electricity tax and distribution cost, only load shifting with electric heating and commercial refrigeration has a positive NPV (b); however, the value is only 33% of the corresponding value with the data from 2013–2015. This is despite the higher standard deviation of the day-ahead electricity price, and may be due to the hypothetical retail price used to determine the electricity price paid for the shiftable loads. With the distribution cost removed, also P2H without boiler becomes profitable, except when combined with all the load shifting sources. Without tax, P2H without boiler is profitable with all load shifting combinations. The positive NPVs are considerably lower than with 2013–2015 data. Hence, both the load shifting and P2H schemes considered here are less profitable in 2050 than in 2013–2015, with P2H only profitable if tax or distribution cost is removed. The strong difference in P2H profitability between 2050 and 2013–2015 is due to the higher day-ahead electricity price in 2050 as the DH price does not change significantly.

The lower profitability of P2H is visible also in the P2H shares of DH (c), which are lower than in 2013–2015. Removing tax results in an over 10% increase. As no FIT is considered, the effect of flexibility measures on the share of VRE sold to spot (d) is in the same order as without FIT in 2013–2015 but slightly lower, showing the lower profitability of the flexibility measures. The less favorable electricity and heat prices for P2H compared to 2013–2015 are also visible in the higher shares of VRE used for P2H: e.g. with P2H and 8 TES units, no load shifting and no boiler, the share is 53–62% in the considered economic cases, compared to 48% in 2013–2015 with no FIT.

#### **4. Conclusions**

In this paper, optimal control models have been presented for studying the technical and economic potential of power-to-heat conversion and load shifting for wind and PV integration in urban areas. The modeled power-to-heat system includes heat pumps and boilers in a district heat system, with both DH network accumulation and separate stratified water tank thermal storages. The load shifting model includes arbitrary shiftable loads, input as time series shiftable for  $n$  hours, and distributed heat storage in electric heating. Separate models for optimal load-VRE matching and cost-optimal market participation were presented. The models are generic and applicable for an arbitrary location and condition, with sufficient input data available. Minor modifications may be needed to the cost optimization model depending on

local taxes and other costs. The models could be directly useful to e.g. urban planners as a tool to analyze the potential of these flexibility sources in their city. With some of the further developments discussed below, they could be developed to operational tools for energy system design or operation optimization of energy companies.

A case study was conducted on the city of Helsinki, Finland with detailed, hourly data. P2H systems were dimensioned to VRE nameplate capacity, with heat pumps delivering 50% of heating power. With optimal load-VRE matching, P2H could consume surplus VRE very effectively above the self-use limit with 35% decrease in surplus without any storage at the highest VRE capacities. Storage could provide 3–6% extra decrease. Load shifting could decrease the surplus by 2–5%. Load shifting could increase the self-use limit of VRE by up to 33%, and P2H by approximately 60–80%, which could be 3–4-folded with storage.

At a VRE configuration providing approximately 50% of the annual electricity demand of the city through self-consumption, P2H with 8 TES units (10,000 m<sup>3</sup> each) or 4 TES units and DH network accumulation could consume all surplus VRE production with optimal load-VRE matching. Load shifting decreased low consumption and surplus powers significantly, and increased peak powers.

With the same VRE and P2H configurations, P2H without boilers had highly positive NPV in 2013–2015 with cost-optimal control. Load shifting with electric heating and commercial refrigeration also had positive NPV, but including other residential loads made the NPV negative due to high investment costs of the required control devices. P2H was observed profitable at the electricity and heat prices in 2013–2015 and used significantly electricity bought from the market, with a major share of VRE sold to the market. However, including the CHP plants in the city with a rule-based simulation made the studied P2H configurations unprofitable because of loss of CHP production. With simulated 2050 prices, the studied P2H configurations were less profitable with negative NPV. This was due to the higher electricity market price compared to DH price than in 2013–2015.

Interesting possibilities for further model development include modeling conventional plants together with P2H and load shifting. The effect of forecast errors could be included to the model, in this case load shifting or P2H could become beneficial for imbalance management. Moreover, the models could be extended to spatial analysis and modeling of the power system and DH network. Operating load shifting or P2H in intraday, balancing or reserve markets in addition to the day-ahead market would be interesting. However, some of those markets would

require more detailed modeling or experimental studies because of the fast, intra-hour dynamics required.

For the Helsinki case study, dimensioning the P2H configurations for compatibility with the CHP plants in the city, perhaps replacing some of the CHP plants with VRE and P2H, would be an interesting topic for further work. The load shifting sources could be complemented by obtaining data on building ventilation, air conditioning and snow and ice melting, e.g. from submetered data [77] or from building managers. The analysis could also be extended from the city of Helsinki to the whole metropolitan area, which is interesting for load shifting due to the higher share of electric heating than in Helsinki where district heating dominates [53].

### **Acknowledgements**

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# Supplementary Information

## Improved flexibility with large-scale variable renewable power in cities through optimal demand side management and power-to-heat conversion

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This supplementary information contains the energy consumption, VRE production and price data description, details on the shiftable load data time series, and the detailed linear formulations of the absolute value objective function and conditional constraints of the mixed-integer linear programs (MILP) in this paper. The rule-based algorithm used for control of conventional plants in the analysis of results is also reported.

### **S1. Energy consumption and PV and wind production data**

The district heat (DH) and PV and wind production data are produced based on weather data. Weather data from 2011 is used for the 2050 case in this paper, in accordance with the price simulations for 2050 [1]. The district heat production in Helsinki in 2013–2015 and 2011 is presented in Figure S1. The heat data was produced based on outdoor temperature at the Kumpula weather station in 2013–2015 [2] and 2011 [3] with a model validated with data from 2006 [4]. DH network losses are included in the heat production. The electricity consumption (Fig. 2 in the

main text) represents a generic year and has been synthesized based on data from 2010 and 2006 [4]. A time series of the DH network supply temperature (Figure S2) was obtained by combining a representative DH supply temperature control curve [5] with the aforementioned outdoor temperature data from Kumpula weather station.

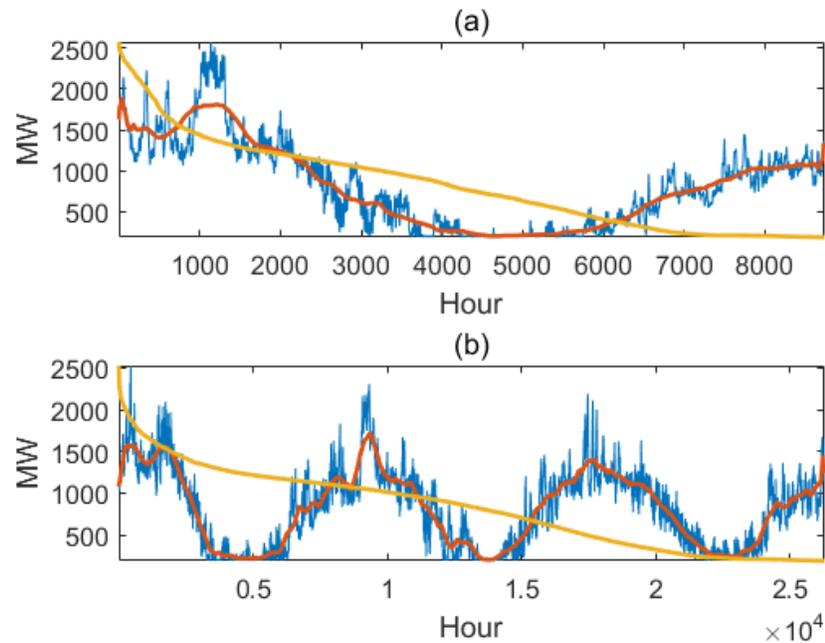


Figure S1. District heat production in Helsinki (blue), 30-day moving average (red) and duration curve (yellow). (a) 2011, (b) 2013–2015.

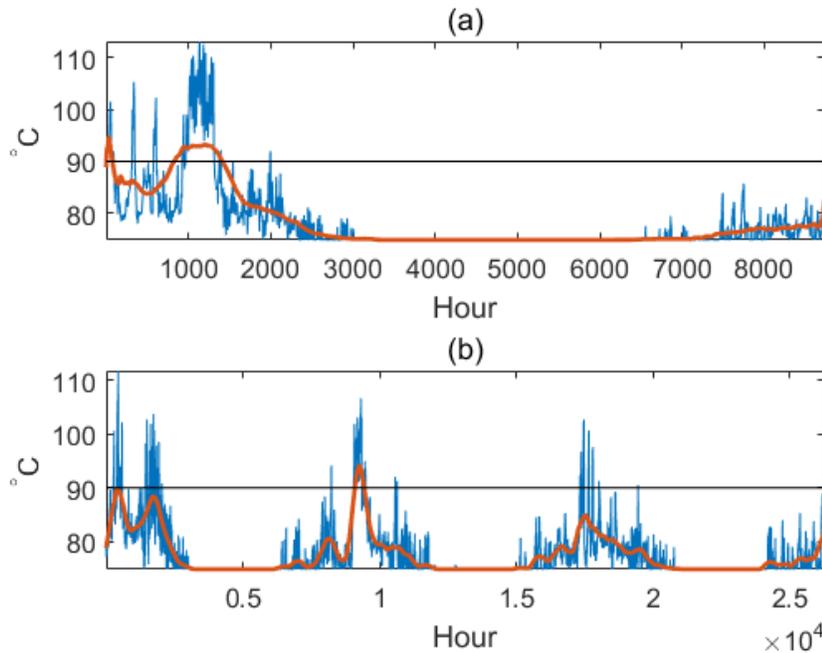


Figure S2. District heat network supply temperature in Helsinki (blue) and 30-day moving average (red). The 90 °C reference line indicates the maximum outlet temperature of DH heat pumps. (a) 2011, (b) 2013-2015.

Figure S3 presents the production of a 1-kW<sub>p</sub> PV system in Helsinki in the corresponding years. The production was simulated with ALLSOL [6] with global and diffuse solar radiation data measured at the Kumpula weather station in 2013–2015 [2] and 2011 [3]. For 25% of the radiation data in 2011, the diffuse component data was unreliable and was replaced with a linear interpolation of the global radiation: 100% of radiation diffuse at sunrise and sunset, 50% at noon. The total annual production in 2013–2015 is 909 kWh/kW<sub>p</sub> and 912 kWh/kW<sub>p</sub> in 2011. The corresponding capacity factor is 0.10 in both periods. Due to the northern location, PV production is concentrated to the summer season. The production of a 3.3 MW wind turbine off the coast of Helsinki is presented in Figure S4. Wind data measured at a weather station on the Harmaja island 6 km from the city was used [2]. The logarithmic wind profile law [7] was used to transform the data to the nacelle height 120 m of a Vestas V105-3.3 MW turbine [8], the power curve of which was used to calculate the power production. The wind capacity factor is 0.33 in 2013–2015 and 0.35 in 2011. Hourly averages of all meteorological data were used, with missing values interpolated linearly.

A detailed analysis of PV direction, shading, and wind farm wake effects is out of the scope of this paper, but they are taken into account in the limits to the VRE capacity. The maximal studied PV penetration (1400 MW<sub>p</sub>) corresponds to 50% rooftop area utilization in the whole city [9]. The maximum number of wind turbines is 500 (resulting in 1650 MW of nameplate capacity), which could be installed to the sea area south of Harmaja with a spacing of 10 rotor diameters. Wake losses due to this spacing have been quantified at 5–10% in the Danish Nysted wind farm [10].

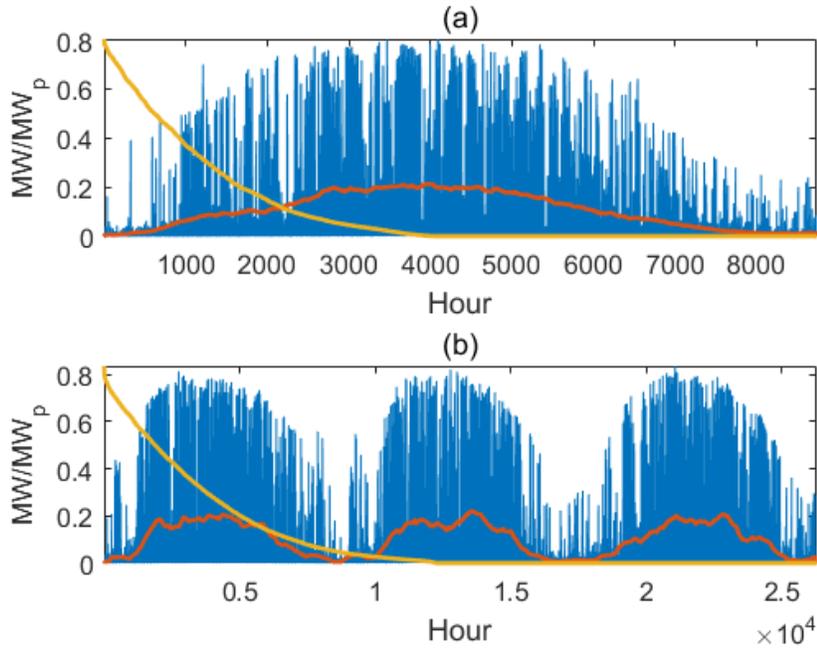


Figure S3. Hourly average PV production in Helsinki (blue), 30-day moving average (red) and duration curve (yellow). (a) 2011, (b) 2013-2015.

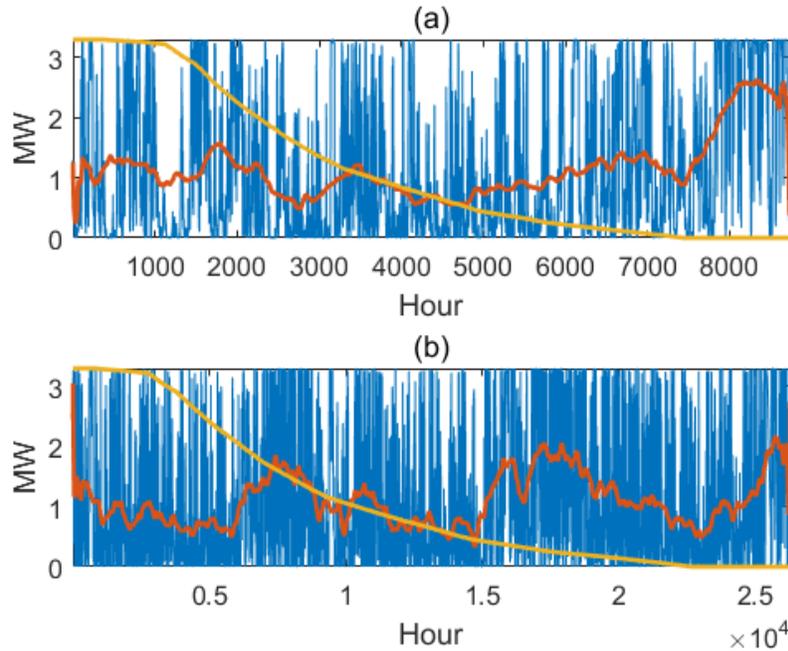


Figure S4. Hourly average wind power production of a 3.3-MW wind turbine off the coast of Helsinki (blue), 30-day moving average (red) and duration curve (yellow). (a) 2011, (b) 2013-2015.

## S2. Price data

The electricity stock market prices and buy and sell volumes for 2013–2015 in Finland in the day-ahead market Elspot were obtained from Nord Pool Spot [11], and energy prices of district heat from the municipal energy company in Helsinki, Helen Oy [12]. For the 2050 case, day-ahead electricity market and district heat prices from a scenario with 48% wind power and 12% PV of total annual electricity consumption in the Nordic and Baltic countries, and Germany and Poland [1] are used. The prices are results from simulations with the Balmorel and WILMAR models.

The Finnish feed-in tariff (FIT) for wind is 83.5 €/MWh [13]. In practice, the FIT is paid based on 3-month average day-ahead market price [13]; a constant FIT is used here for simplicity. Prices without valued added tax (VAT) are used, as the actor can deduct the VAT it has paid from the VAT it receives from its customers. Additional taxes in the district heating price are neglected as they depend on the fuels used for the production; their share is on average minor compared to VAT [14]. The price paid for the surplus PV by the market actor  $\pi_{PV,surplus}$  is the spot price subtracted by a commission of 0.24 c/kWh, as paid by the Finnish utility Fortum [15].

The P2H conversion systems have to pay electricity tax  $\pi_{e,tax}$  [16]. Distribution costs were obtained from the DSO in Helsinki [12]. The price  $\pi_{DSM}$  is obtained as the average of Finnish electricity retail prices in 2013–2015 [17] subtracted with a 5% compensation for load control [18]. For the 2050 case, a constant retail price is formed such that the average margin compared the day-ahead price equals that in 2013–2015, and the same load control compensation is applied.

Variable operations and maintenance (O&M) costs of VRE production, heat pump and boiler operation and load shifting are neglected. There is high variation in estimates of variable O&M costs of VRE and the minimum values are minor [19], even zero for PV [20]. Literature values for heat pump [21], boiler [22] and load shifting [23] variable O&M costs are minor as well.

When determining the investment and fixed costs, induction motors with power factor 0.9 are assumed for the heat pumps [24]. The electric boiler costs correspond to electric resistance boilers, which are almost twice as expensive as larger electrode boilers [22]. Hence, the boiler investment cost may be overestimated, but the resistance boiler costs are used as they are required to some extent for controllability without minimum load. Construction, real estate and network connection point costs possibly required by heat pumps or electric boilers are excluded from the analysis.

Finland is a forerunner in smart meter implementation: smart meters with remote reading and load control capabilities have been installed to at least 80% of the consumers by the end of 2013, as required by the government [25]. Finnish DSOs have tried to install smart meters to even all their consumers [26]. Typically, the meters are equipped with a load control relay that is used to control electric heating. Hence, no investment or fixed costs are assumed for electric heating. Residential cold and wet appliances require separate control boxes for each appliance, assumed to cost 208 € per box [27]. The total investment cost in Table 2 in the main text is obtained from appliance ownership [28] and the number of households in Helsinki [29]. As data exchange options are available through e.g. Internet connections in the households and connections offered by the smart meters, no fixed costs due to data exchange are assumed.

### **S3. Shiftable load time series data**

The residential cold and wet appliance consumption was obtained based on data from an appliance-level measurement campaign conducted in Sweden in 2005-2008 on 201 detached houses and 188 apartments [30]. As the time use in Sweden [31] and Finland [32] is very similar, appliance use patterns can be assumed the same. Average consumption time series of the considered appliances for detached houses and apartments were calculated separately from the sample data for the year 2007. Appliance ownership in the sample was scaled to the average ownership in Helsinki [28], and the total consumption in Helsinki was obtained by scaling with the number of detached houses and apartments in the city [29]. Due to lack of data, the distribution of device properties in Helsinki and the sample had to be assumed the same. The cold appliances are shiftable for 1 h due to their thermal mass [33] and wet appliances for max. 8 h.

Empirical time series at hourly resolution of annual electricity consumption of refrigerators and freezers in a supermarket, and three freezer warehouses were obtained from SEAM Oy [34]. To obtain the total capacity of these loads, dimensioning of refrigerators and freezers in grocery stores in three size classes [35] was combined with the numbers of the stores in the size classes in Helsinki, obtained from chain store websites [36–42]. The available data from a single supermarket was scaled to the total capacity. The time that these loads can shift their consumption ranges from 1 h to 25 h, depending on the controlled power and state of the devices [43]. As control of the full capacity is allowed here and information of device states is not available, a conservative value of 1 h is used. Because the data shows mainly diurnal and seasonal variations and the dynamics of

the load is in the order of the time resolution, no smoothing of the data was done. The data available from the three freezer warehouses was scaled to the total capacity of nine warehouses in Helsinki [44]. Freezer warehouses are shiftable for max. 4 h [45].

The annual consumption of electric resistance heaters and ground source heat pumps ( $COP \approx 3$ ) in building heating in Helsinki was obtained from statistical data on building heating [46], a nominal space heating demand of  $125 \text{ kWh/m}^2$  [47], and nominal domestic hot water (DHW) demands per floor area [48]. Space heating time series were formed with the hourly heating degrees method [49] with a  $17 \text{ }^\circ\text{C}$  basis, conventional in Finland [50]. The DHW consumption pattern for DH [4] was utilized here, as the distribution of customer groups is similar. The resistance heating systems without water tanks, and heat pump systems are shiftable for 1 h [51], which is a conservative figure but attainable with all the technologies falling to this category.

Following the approach in [51], all hydronic resistance heating systems built in 1980-2009 were assumed to have water tank storage. The electricity tariffs at the time incentivized storage heating, while the contemporary tariffs are less variable and energy efficiency regulations more demanding [51]. The building heating statistics only consider the main heat source of each building, hence the current increasing trend in air-source heat pump use is not included. Conventional dimensioning, 50% of peak day consumption [50], and a typical efficiency  $\eta_{sto} = 0.95$  [50] were assumed for the storage heating systems. The storage charging power is limited to 18 kW per building, assuming typical 3 x 35 A fuses [50]. When DSM is not employed in the optimization, the storage heating systems are assumed to follow a night-day control.

#### **S4. Objective function with absolute value in the load-VRE matching optimization problem**

A technique presented in [52] for linear formulation of minimization of an objective function with an absolute value function is employed here. The absolute value terms in the objective function  $|P_{VRE,k} - Q_{e,k}|$  are replaced with  $Q_{residual,k}$ , which are constrained as

$$P_{VRE,k} - Q_{e,k} \leq Q_{residual,k}, \quad (\text{S1})$$

$$-(P_{VRE,k} - Q_{e,k}) \leq Q_{residual,k}. \quad (\text{S2})$$

## S5. Conditional constraints

The conditional constraints in the optimization problem arise from the accumulated heat taking precedence in fulfilling the heat demand:

$$\text{If } S_{k+1} > 0, Q_{h,surplus,k} = 0. \quad (\text{S3})$$

The well-known technique of “big  $M$ ” and driving binary variables  $y_k$  [53] is used here to formulate the constraints linearly.  $M$  is a constant satisfying  $M \gg S_{max}$  and  $M \gg Q_{h,max}$ .  $M=10^6$  was used in this work.

$$Q_{h,surplus,k} \leq My_k, \quad (\text{S4})$$

$$y_k \in \{0,1\}, \forall k, \quad (\text{S5})$$

$$y_k = \begin{cases} 1, & S_{k+1} = 0 \\ 0, & S_{k+1} > 0. \end{cases} \quad (\text{S6})$$

The conditionality in Eq. (7) is formulated as follows, employing a small positive constant  $\varepsilon$  to avoid strict inequalities:

$$\begin{cases} My_k + S_{k+1} \geq \varepsilon \\ S_{k+1} - M(1 - y_k) \leq \varepsilon. \end{cases} \quad (\text{S7})$$

The value of  $\varepsilon$  was set in this work to the double-precision floating-point relative accuracy from 1.0,  $2^{-52}$ .

## S6. Rule-based plant control algorithms

The plant control algorithms are based on [54]. Either electricity or heat net load is followed. There are three CHP plants in Helsinki: Vuosaari (natural gas, 630 MW electricity, 580 MW heat), Hanasaari (coal, 220 MW electricity, 420 MW heat), and Salmisaari (coal, 160 MW electricity, 300 MW heat). In addition, there are 13 heat-only boilers (HOB), able to produce 2370 MW of heat in total. The CHP plants are also allowed to run in condensing mode in the simulation, producing only electricity with the maximum powers 696 MW, 284 MW and 204 MW, respectively. Minimum loads and start-up and shutdown times [55] limit whether the CHP plants can be run or not. When running, all the plants can be controlled between minimum load and full capacity during the 1-hour time step [55]. The CHP plants are assigned a constant order of priority: 1. Vuosaari, 2. Hanasaari, 3. Salmisaari. After that, the HOBs are run in fuel-determined priority: first the gas HOBs are run, then the oil-burning ones, and the coal HOBs last.

The algorithm is as follows on each time step:

1. Try to run the plants at full power in the order of priority and CHP plants in CHP mode, without exceeding the electricity/heat net load.
2. Try to run the plants not yet running to match the electricity/heat net load, in the order of priority and CHP plants in CHP mode. If the required production for plant  $i$  is less than its minimum load, the preceding plants try to lower their production to allow for plant  $i$  running at minimum load, in reverse order of priority. If this is not successful, plant  $i$  is shut down.
3. If the electricity net load is being followed and the heat net load is exceeded:
  - 1) The running CHP plants are changed to condensing mode one by one in reverse order of priority until the heat net load is not exceeded, adjusting their production to the electricity net load. If the required production for plant  $i$  is less than its minimum load, the next running plants in the reverse order of priority try to adjust their CHP mode production to allow for minimum load of plant  $i$ . If this is not successful, plant  $i$  is shut down.
  - 2) Start of the plants not running is attempted in condensing mode to match the electricity net load. If the required production for plant  $i$  is less than its minimum load, the plant is shut down.

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